

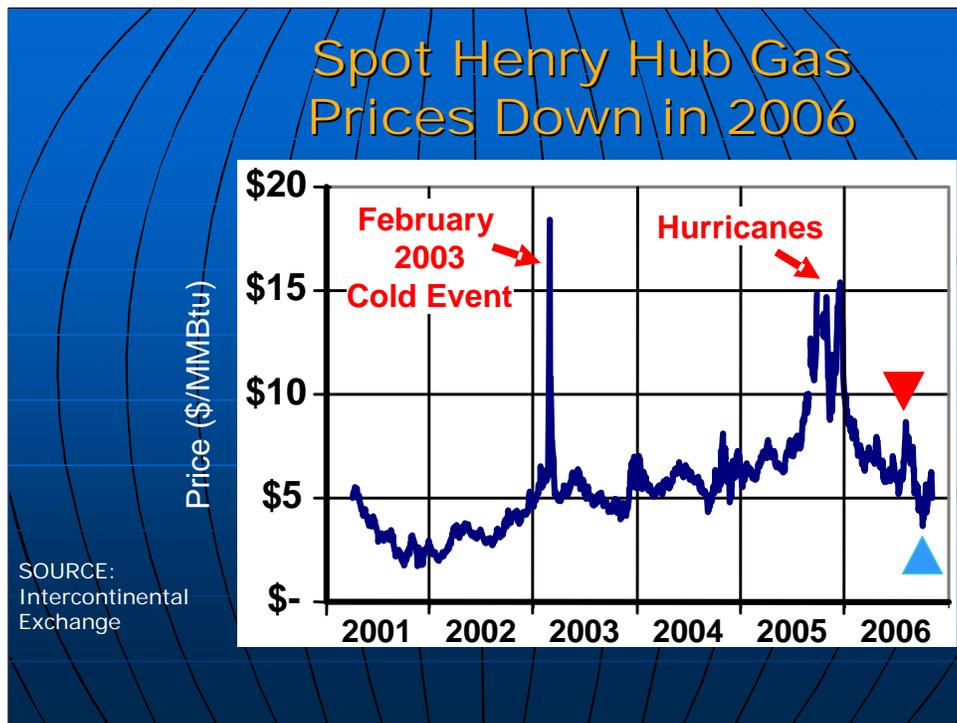


Winter 2006-07 Energy Market Assessment

Item No.: A-3
October 19, 2006

Good morning Mr. Chairman and Commissioners. Today I'm pleased to present the Office of Enforcement's Winter 2006-2007 Energy Market Assessment. After I'm finished, I'll turn over the presentation to Jeff Wright of the Office of Energy Projects to discuss infrastructure issues.

The Winter Assessment is designed to share our opinions about those markets that the staff of the Division of Energy Market Oversight will be watching most carefully throughout the winter. Even so, the issues I present today are certainly not the only areas we are watching. The prospects for this winter look as good as they have for some time. Current spot prices are relatively low, certainly at their lowest levels since last year's hurricanes. These lower spot prices reflect strong storage inventories across a whole set of fuels, particularly natural gas. In addition, as of now, most predictions for winter weather are mild. These conditions exist despite increased natural gas use last summer due to heat and fuel switching away from oil. While staff does not predict prices, the current conditions for natural gas indicate that the system has significant flexibility to deal with most challenges that might arise through the winter.

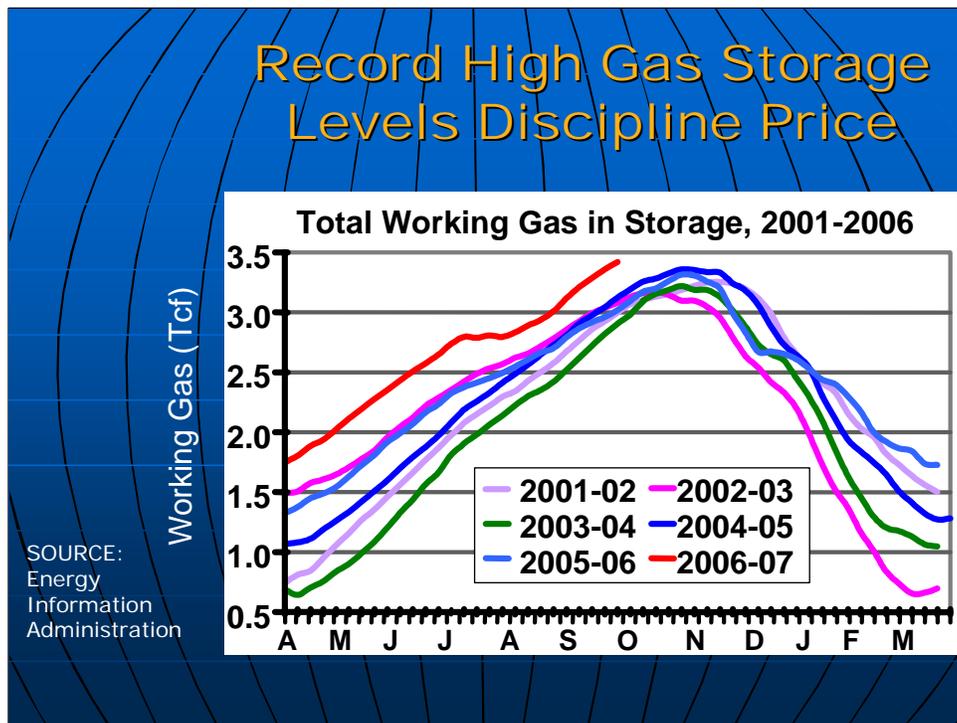


Current natural gas prices are low compared to the past few years. The graph shows a longer-term view of next-day spot natural gas prices as traded at Henry Hub, Louisiana, on the Intercontinental Exchange. We've labeled the two price peaks: the narrow one to the left-of-center in February 2003 was due to a late cold front when storage was low and the more extended peaks to the right occurred during the period after last year's hurricanes Katrina and Rita. Since then, spot prices have generally fallen.

A short peak of over \$8.50/MMBtu, labeled with the red arrowhead, occurred in early August during one of last summer's widespread heat waves that was characterized by significant increases in natural gas use in electric generation. The most recent low price was for natural gas delivered the first weekend this month, when prices at Henry Hub fell to \$3.66/MMBtu. That brief drop brought prices to their lowest level in 4 years.

As of the middle of this week, prices have risen back to above \$6.00/MMBtu. This week's rise is due to several factors including stronger-than-normal demand due to early cool weather in the Midwest, continued incentives for storage injections, and fuel switching I will discuss later. In addition, given tight storage conditions, day-to-day prices have become volatile, with drops across weekends associated with lower demand and increases during the week. Most likely, over the next few weeks, prices will remain volatile, but still relatively low.

Record High Gas Storage Levels Discipline Price

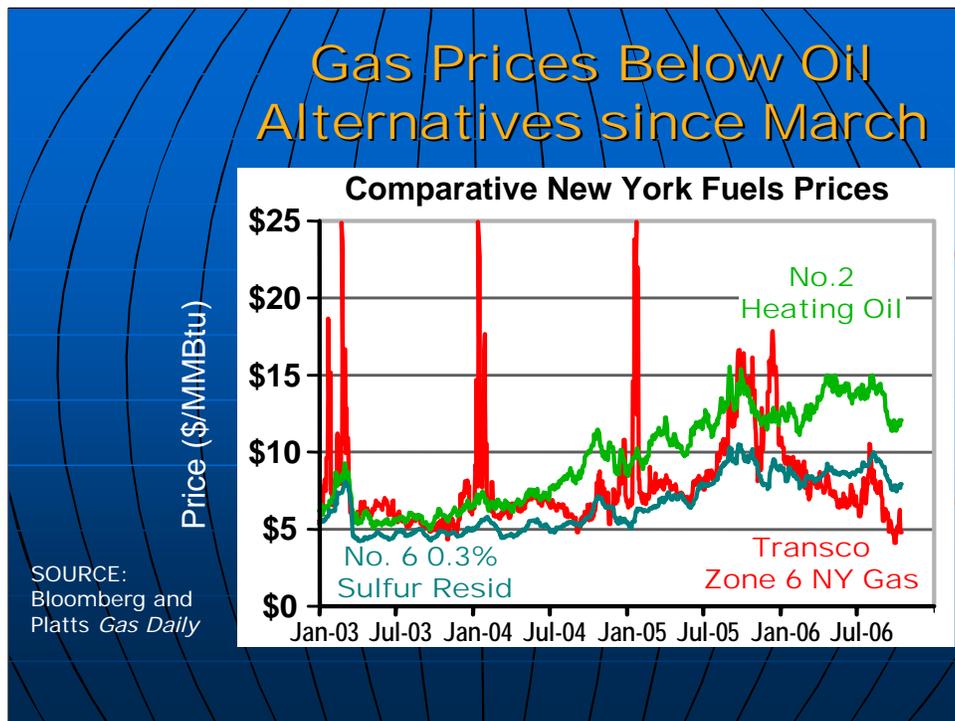


The most significant single factor in the recent low prices of natural gas is extremely high storage levels. Last week's report of working gas inventories in storage of 3,389 Bcf is a recent record, well above storage fills over the past decade. The red line on this graph compares this year with the previous five storage injection and withdrawal cycles and shows how much higher the current U.S. storage level is. With three or four weeks of injections remaining this year, we will likely see inventories surpass their all-time high of 3,472 Bcf recorded at the end of November, 1990.

This high level of storage began with the very low withdrawals last winter due to record mild weather. This early 2006 surplus was sustained despite a summer when natural gas was used in unprecedented amounts to generate electricity during several geographically dispersed heat waves. In fact, the Energy Information Administration's report of 786.5 Bcf of gas burned to generate electricity in the United States in July 2006 was the highest monthly delivery for that use over the past five years. As a result of these heat waves, the National Oceanic and Atmospheric Administration indicated that July was the second warmest since 1895, while August was the 11th warmest.

The resulting use of natural gas to generate electricity is reflected on the graph in the "dip" in injections in July and August – including two weeks of rare summer withdrawals to meet electric generation demands.

Gas Prices Below Oil Alternatives since March



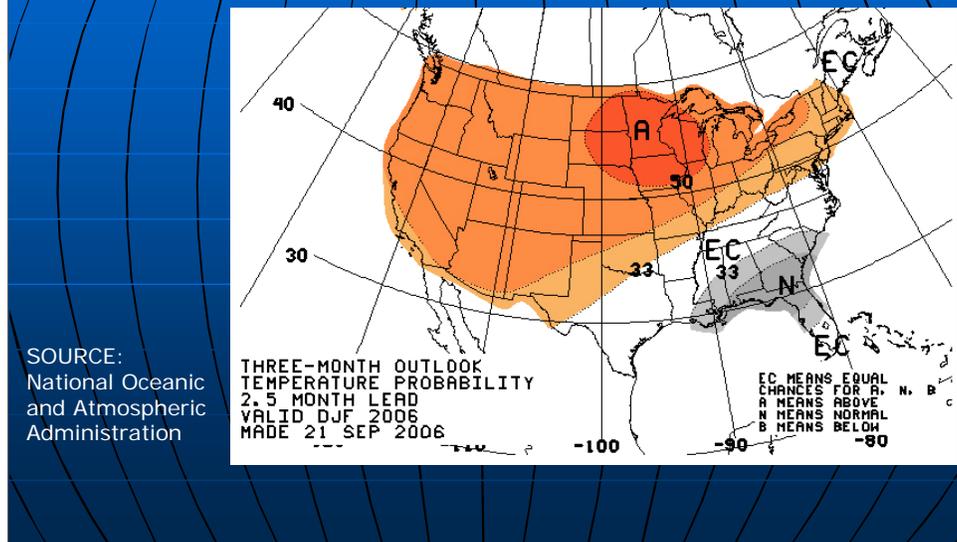
One factor in the increased use of natural gas in electric generation has been its relative attractiveness versus competing fuels. Gas has not generally become competitive with coal, but certainly has with oil. This graph of competing fuel prices in New York since 2003 shows the historical relationship of gas and various oil prices. In general, natural gas prices, in red on this graph, remain between heating oil, in green, and low-sulfur residual fuel oil, in teal. The exceptions, in the past few years, have occurred during short periods of extreme cold in the northeast, in January of 2003, 2004 and 2005. The peak in February 2003 was due to high national prices.

This historical relationship broke down in early March, and New York natural gas prices have remained below low-sulfur resid since, with a brief exception in the summer peak price I discussed earlier. This is the longest sustained period of lower gas than resid prices we've seen in many years.

Consistent with that relationship, we've seen switching from oil, particularly noticeable in New York and in Florida.

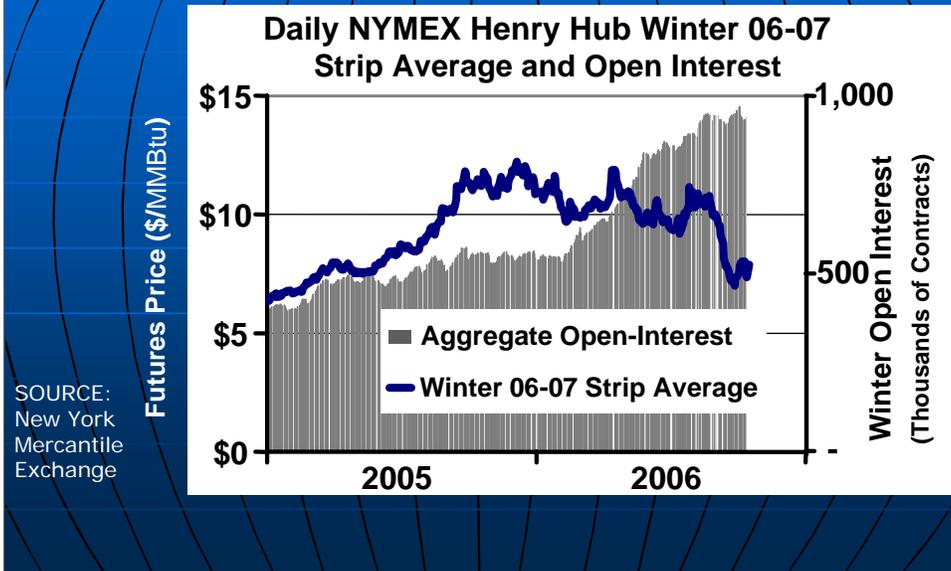
Currently, swap markets do not indicate that market participants believe this relationship will last into the winter, and indicate higher gas prices relative to oil. Weather is likely to be the most important determinant in this price relationship.

NOAA's Winter Weather Forecast is Mild



Any sustained increase in spot gas prices at this point would likely be due to weather. The most current NOAA forecast for the winter is almost a month old, but I show it to observe that forecasts still tend to indicate mild expectations for the winter. This forecast, for December 2006 through February 2007 shows widespread above-normal temperatures from across the West and east into New England and New York. Outside that area, forecasts are closer to normal. Nowhere on the continental United States is the weather indicated to be below normal. More recent forecasts seem to indicate closer-to-seasonal weather, but not cold. No one currently expects the winter to be as warm as last year.

Winter Futures Prices Have Moderated



If we attempt to assess market expectations for the winter of 2006-2007 using futures prices, we see the recent moderation in prices extended into the winter as well. The blue line on this graph is the average futures price of November 2006 through March 2007 contracts. Through early 2005 and into the hurricanes, prices increased from a little over \$6.00/MMBtu to over \$10.00/MMBtu. Only more recently have prices fallen significantly, briefly dropping to under \$7.00/MMBtu a few weeks ago and rising even more recently around \$8.00/MMBtu. This drop appears to reflect a reassessment for the prospects for winter prices.

This is the drop in futures prices that finished-off hedge fund Amaranth Advisors.

We've also graphed the open interest in the futures market for same period, using grey columns. I would note that, despite Amaranth's loss and subsequent sale of its natural gas positions, activity in the futures market related to this time period has remained fairly stable at record levels, not decrease. To some degree, that level of interest may be seasonal. Still, despite a spectacular failure by an active participant in financial natural gas markets, winter positions remain significant.

I should note that the wholesale price decreases I've discussed here today will not be fully reflected in retail prices this winter. Distribution companies will use gas in storage, injected at higher average prices than we see today, and will receive gas purchased under longer-term contracts. These activities protect reliability and moderate retail price volatility. In a falling market, however, they do moderate price decreases. Distributors should not be discouraged from using these important purchasing tools simply because of higher retail prices over the short-term.

Altogether, conditions faced by U.S. natural gas markets at the onset of the winter appear to be stronger than in recent years, reflecting continued strong storage levels and forecast mild weather. Weather might force prices up through the winter, but weather is still expected to be relatively mild.

Oversight staff will continue to watch these areas throughout the winter, on every trading day, and report back to you as needed.

Natural Gas Infrastructure Review: Pipelines, Storage, LNG

- Approved
- Pending
- Potential
- In-service in 2006

Thank you, Steve. Good morning Mr. Chairman and Commissioners.

This morning I would like to take a brief look at the natural gas infrastructure – pipelines, storage and LNG terminals – that the Commission has approved in recent years and also what projects are before the Commission and what projects may be expected in the not too distant future.

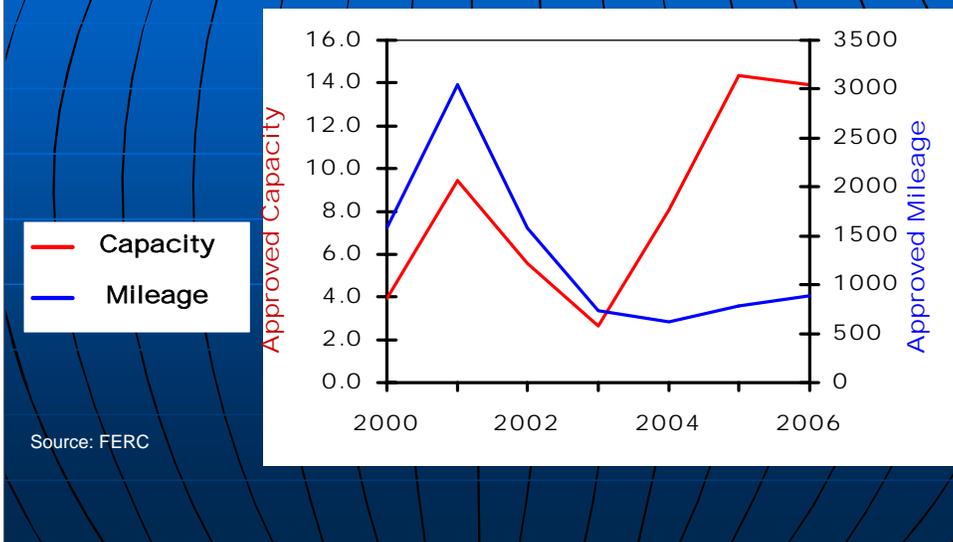
Pipeline Approvals 2000-2006

	Capacity (Bcf/day)	Miles of Pipe	Compression (HP)	Cost (Billions)
2000	3.9	1,575.6	246,096	1.6
2001	9.5	3,044.1	820,270	5.0
2002	5.6	1,575.8	536,064	3.1
2003	2.7	734.5	266,525	1.9
2004	8.1	619.3	83,538	1.2
2005	14.3	785.1	123,036	1.6
2006	13.9	890.3	205,525	2.6
TOTAL	58.0	9,224.7	2,281,074	17.0

Source:
FERC

This slide give a summary of the pipeline facilities that the Commission has approved from the beginning of 2000 until the present. These approvals total 58 Bcf per day of pipeline capacity, over 9,200 miles of pipeline, and about 2.3 million horsepower of compression at an estimated cost of approximately \$17 billion.

Purpose of Pipeline Varies Over Time



Here, I've taken the information on capacity and mileage from the last slide to show how, over the last few years, there has been a dramatic change in the amount of capacity approved vis-à-vis the amount of mileage approved. This can be attributed to the different purposes of the facilities. Approvals in the first few years of this decade can be characterized as typical; that is, new long-line pipelines or additions to existing pipelines. Recently, we have seen a rise in high-capacity, short mileage pipelines associated with proposed LNG terminals.

Pipeline Infrastructure - Pending Applications

- 18.1 Bcf/day of capacity
- 1,955 miles of pipeline
- 50% of capacity - LNG related
- Gas source for projects slowly changing

Currently, there are numerous projects before the commission totaling about 18 Bcf per day of capacity and nearly 2,000 miles of pipeline. The trend here is that while there are still pipeline projects dedicated to LNG projects – approximately 50% of capacity – there are more projects popping up to transport North American production – the Rockies Express West from the Rockies to Missouri, Gulf South's expansion to bring Barnett shale gas out of Texas, and the Empire Connector and Millennium pipelines to bring gas to the Northeast.

Pipeline Infrastructure - Prefiling

- 12.2 Bcf/day of capacity
- 2,396 miles of pipeline
- Little LNG-related capacity
- Major projects to transport Rockies gas and non-conventional sources of gas

In our pre-filing category – those cases that are beginning their environmental review prior to making a formal filing with the commission – the tide is truly changing. Out of 12.2 Bcf per day of capacity and nearly 2,400 miles of pipeline, only 1 Bcf per day of capacity and 223 miles of pipeline is associated with LNG. One major project in pre-filing is an extension of the Rockies Express West, the Rockies Express East that will extend from Missouri through Ohio. There are also projects seeking to transport more of the Barnett shale gas out of Texas to interconnections with interstate pipelines in the Southeast.

Pipeline Infrastructure - Potential

- 15.2 Bcf/day of capacity
- 6,979 miles of pipeline
- No LNG-related capacity
- Contains Alaska capacity
- Projects focused in the Southeast

Taking a quick look at potential projects that may be filed within the next couple of years, we see the potential for over 15 Bcf per day of capacity and nearly 7,000 miles of pipeline. None of these potential projects are directly related to LNG terminals. I do note that these totals contain an amount for the transportation of Alaskan North Slope gas to the Lower 48 which is currently in a state of flux to the lack of an approved contract between the state of Alaska and a potential transporter or transporters. Otherwise, it appears that we can expect much pipeline activity in the Southeast in the future.

Gas Storage Approvals: 2000-2006

- 275 Bcf of storage capacity
- 14.6 Bcf/day of deliverability
- Majority of proposals in Southeast
 - Proximity to salt formations
 - Proximity to LNG development

Changing the focus to storage, I would note that since 2000, the Commission has approved 275 Bcf of storage capacity and daily delivery from storage of 14.6 Bcf. Storage proposals, especially in recent years, have centered around the Southeast/Gulf Coast area where high-delivery salt formations can be utilized to store regasified LNG in addition to traditional gas production from this region.

Storage Infrastructure: Pending and Potential

- Pending
 - 79.2 Bcf of storage capacity, 1.8 Bcf/day of deliverability
- Potential
 - 124.5 Bcf of storage capacity, 4.4 Bcf/day of deliverability
- Majority of proposals in Southeast and Northeast
- Lack of development in the West

The Commission has two storage projects pending – one in Michigan and one in Alabama – that total 79.2 Bcf of capacity and 1.8 Bcf per day of deliverability. Down the road, we see the potential for projects totaling about 125 Bcf of capacity and over 4 Bcf per day of deliverability. The majority of these possible projects appear to be located in the Southeast and the Northeast. What is notable is the lack of prospective storage development in the western U.S.

LNG Approvals: 2002-2006

- 11 new terminal sites
 - Redelivery capacity of 20.6 Bcf/day
 - 10 sites on Gulf Coast, one in the Northeast
- 3 expansions
 - Redelivery capacity of 4.7 Bcf/day

Looking now at LNG development, we see that since the advent of the Hackberry Policy in December 2002, the Commission has approved 11 new terminal sites. All except for one, are located on the Gulf Coast. The total sendout of the approved terminals is 20.6 Bcf per day. In addition, the Commission has approved an expansion at Dominion's existing Cove Point, Maryland terminal as well as expansions at the approved, but-yet-to-be-built Freeport and Sabine Pass terminals which total 4.7 Bcf per day in new sendout capacity. The total approved sendout capacity exceeds 25 Bcf per day.

LNG Infrastructure: Pending and Potential

- Pending
 - 10 new terminal sites
 - Redelivery capacity of 9.5 Bcf/day
 - Sites on Gulf Coast, Northeast, California and Oregon
 - 2 expansions
 - Redelivery capacity of 2.1 Bcf/day
- Potential
 - 9 new sites
 - Redelivery capacity of 6.5 Bcf/day

The Commission is currently processing applications for ten new LNG terminals with a combined redelivery capacity of 9.5 Bcf per day. Additionally, there are expansions proposed at Southern LNG's existing Elba Island terminal and at the approved Cameron LNG terminals totaling another 2.1 Bcf per day of deliverability. All told, there is a combined 11.6 Bcf per day under analysis at the Commission.

[Note: the Coast Guard and Maritimes Administration are reviewing 8 offshore sites with a combined capacity of 8.1 Bcf per day.]

On the horizon, we see the potential for 9 more onshore and offshore sites in preliminary planning stages with a combined sendout of about 6.5 Bcf per day.

What Has Been Placed Into Service in 2006?

- Pipelines
 - 8 Projects: 3.3 Bcf/day, 717 miles
- Storage
 - 3 Projects: 32.4 Bcf of storage, 0.5 Bcf/day of deliverability
- LNG
 - 2 Terminal Expansion Projects: 2.7 Bcf of storage, 1.1 Bcf/day of deliverability
 - 1 Pipeline Expansion: 1.5 Bcf/day, 23 miles

In conclusion, I would note that so far in 2006, we have seen pipeline projects go into service with a combined capacity of 3.3 Bcf per day. There have been three storage projects commence service this year with a combined capacity of over 32 Bcf and about 0.5 Bcf per day of deliverability. Expansions at two LNG terminals – Elba Island and at Trunkline LNG's Lake Charles facility – went into service offering a combined additional sendout of 1.1 Bcf per day. There was also a new pipeline put into service, dedicated to transporting up to 1.5 Bcf per day from the Lake Chares facility.

This concludes the presentation. Steve and I will be happy to answer any questions you may have.