UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Sea Robin Pipeline Company, LLC § Docket No. RP07-_____-000

PREPARED DIRECT TESTIMONY OF MICHAEL T. LANGSTON

Q. Please state your name and business address.

A. My name is Michael T. Langston. My business address is 5444 Westheimer Road, Houston, Texas 77056.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Sea Robin Pipeline Company, LLC ("Sea Robin").

Q. What are your responsibilities with Sea Robin?

A. I am Senior Vice President, Government and Regulatory Affairs with primary responsibility for rate and regulatory matters for Sea Robin.

Q. Please describe briefly your educational and professional background.

A. I received a Bachelor of Science Degree in Electrical Engineering with honors from the University of Texas in Austin in 1975. I received a Master of Business Administration from Southern Methodist University in Dallas, Texas in 1978. I was employed by Mobil Pipeline Company from 1975 to 1979 in various positions in their engineering department. From 1979 to 1986, I was employed by Texas Oil & Gas Corp. and its affiliate, Delhi Gas Pipe Line Corporation, holding various positions in corporate planning, special projects, and project development. I joined Southern Union Company ("Southern Union") in September 1986 and have been employed by Southern Union and its affiliates since that time, holding various positions involving gas supply, marketing, gas control, contract administration, and federal regulatory areas. I am also a Registered Professional Engineer in the states of Texas, Louisiana, and Oklahoma.

Q. Have you previously testified or presented testimony before the Federal Energy Regulatory Commission?

A. Yes. I provided testimony in Docket No. RP07-34-000 on behalf of Southwest Gas Storage Company, in Docket No. RP06-614-000 on behalf of Transwestern Pipeline Company, LLC, in Docket No. RP04-249-000 on behalf of Florida Gas Transmission Company, LLC and in Docket No. RP88-44-000 on behalf of Southern Union Gas Company.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: (1) provide the background of this proceeding; (2) discuss the overall rate filing, return on equity, capital structure, and testimony and support offered by other Company witnesses; (3) explain the Test Period adjustments to billing determinants and throughput, and associated revenues underlying Sea Robin's proposed rates, and discuss the supporting data; and (4) describe the current business risks.

Q. Please briefly describe the prepared testimony of Sea Robin's other witnesses in this proceeding.

A. First, Mr. Lawrence J. Biediger, Senior Director of Rates, describes the overall Cost of Service calculations including Rate Base and Return, Accumulated Deferred Income Taxes, Regulatory Assets and Liabilities, Depreciation, Operation and Maintenance Expenses, Federal and State Income Taxes, At-Risk Revenues, Other Revenues, Miscellaneous Revenues and Gas Balance.

Second, Mr. Rickey J. Brocato, Rate Manager, describes the Gas Plant, Accumulated Provision for Depreciation, Working Capital and Taxes Other Than Income.

Third, Mr. William W. Grygar, Vice President of Rates & Regulatory, will describe cost classification, cost allocations, discount adjustment, and overall rate design. In addition, he will describe the Base Period revenues and billing determinants, and the Test Period revenues and billing determinants.

Fourth, Mr. Robert B. Hevert, President of Concentric Energy Advisors, provides support for Sea Robin's cost of equity capital.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

Exhibit No.	Reference	Description
SR-2	**Non-Internet Public**	Map of Sea Robin's system
SR-3		Proposed Tariff Sheets
SR-4	Statement F-2 Statement F-1 Statement F-4	Capitalization
SR-5	Statement F-3	Debt Capital
SR-6		FERC Allowed Certificate Returns

SR-7		Historical Firm and Interruptible Volumes
SR-8	Schedule G-3(a)	Adjustments to Reservation Quantities
	Schedule G-3(b)	Adjustments to Usage Quantities
SR-9		Gulf of Mexico Oil and Gas Production Forecast: 2004-2013
SR-10		Gulf of Mexico EIA shallow water Gas production forecast: 2004-2030
SR-11		Newfield Exploration News Release
SR-12		Gulf Gateway Deepwater Port
SR-13		Northeast Gateway Deepwater Port

Q. Please outline the corporate structure under which Sea Robin is owned and operates.

A. Sea Robin is a limited liability company which is owned 50% by Trunkline Offshore Pipeline, LLC and 50% by Trunkline Deepwater Pipeline, LLC. These entities are in turn owned 100% by Panhandle Holdings LLC, which is owned 100% by Panhandle Eastern Pipe Line Company, LP ("Panhandle"). Panhandle is in turn ultimately owned 100% by Southern Union, a Delaware corporation.

System Overview and Background of This Proceeding

Q. What is the reason for this rate case filing?

A. This rate case is being filed to allow Sea Robin the opportunity to recover its annual cost of service.

Q. When and for what purpose was Sea Robin formed?

A. Sea Robin was formed as an unincorporated, joint venture by subsidiaries of United Gas Pipe Line Company ("United") and Southern Natural Gas Company ("Sonat") in 1970 as a means of accessing the natural gas reserves in shallow federal waters (water depths of less than 600 feet) of offshore southwestern Louisiana. A map of Sea Robin's pipeline system, including compressor stations and major interconnects, is shown in Exhibit No. SR-2.

Q. Has Sea Robin's role changed since its formation?

A. Yes. Sea Robin has evolved from having a merchant function, that is primarily selling gas to its parent companies United and Sonat, to providing transportation services for producer/shippers who are developing reserves in this area of the Gulf of Mexico.

Q. Please describe Sea Robin's business activities.

A. Sea Robin is engaged in the business of gathering and transporting natural gas and liquid hydrocarbons, including condensate, supplies from various points in the Gulf of Mexico, offshore Louisiana, for processing and delivery to the interstate/intrastate transmission grid in the vicinity of its onshore terminus near Erath, Louisiana in Vermilion Parish. The interconnecting pipelines which take gas from Sea Robin include (a) six interstate pipelines: Columbia Gulf Transmission Company ("Columbia Gulf"), Gulf South Pipeline Company, LP ("Gulf South"), Sabine Pipeline, LLC ("Sabine"), Sonat, Texas Gas Transmission, LLC ("Texas Gas"), and Trunkline Gas Company, LLC ("Trunkline"), an affiliate of Sea Robin; (b) one intrastate pipeline: Bridgeline Holdings, L.P. ("Bridgeline"); and (c) one storage field: Jefferson Island Storage & Hub, LLC ("Jefferson Island Storage").

Q. Please describe the Sea Robin system infrastructure.

A. Sea Robin operates a network of 477 miles of dual phase pipelines which gather a raw stream of natural gas and liquid hydrocarbons, including condensate, which has not been separated or processed. During the base period Sea Robin collected gas and liquids from 66 gathering and 13 transmission receipt points in numerous production fields offshore. Collected gas and liquids are moved to shore for liquids separation, dehydration, processing and delivery to the pipelines identified above. The production surrounding Sea Robin lies in the Outer Continental Shelf ("OCS") of the Gulf of Mexico, including blocks in the West Cameron, East Cameron, Vermilion, South Marsh Island, Eugene Island, and Ship Shoal Areas. Sea Robin also owns an undivided interest in an offsystem lateral connected to Transcontinental Gas Pipeline Corporation.

Q. Please describe the offshore portion of the Sea Robin system.

A. Sea Robin is configured in the form of an upside-down "Y". The size of pipeline comprising Sea Robin ranges from 4-inch diameter pipeline to 36-inch diameter pipeline. The western branch of the "Y" ("West Leg") runs north from East Cameron Block 335 to East Cameron Block 195, where it bends toward Vermilion Block 149. The eastern branch ("East Leg") extends northwest from Eugene Island Block 205 to Vermilion Block 149. The East Leg splits at Eugene Island Block 205, with one branch running southeast to Ship Shoal Block 222 and a second branch ("J Leg") continuing southwest to South Marsh Island Block 128. The East Leg and West Leg converge at Sea Robin's offshore compressor station located in Vermilion Block 149. The 36-inch diameter mainline runs north from Vermilion Block 149 onshore to the terminus of the system near Erath, Louisiana in Vermilion Parish. The Vermilion Block 149 platform houses a central compressor station.

Sea Robin's facilities upstream of Vermilion Block 149 compressor station are classified as gathering. The facilities downstream of the Vermilion Block 149 compressor station are classified as transmission. This functionalization of the Sea Robin system was established by the Commission in Docket No. CP95-168-000.

Q. Please describe the onshore portion of Sea Robin's system.

A. Sea Robin delivers its raw gas stream onshore to two processing plants: a plant operated by Devon Energy Corporation ("Devon Plant"), which physically separates natural gas from free liquids, including condensate and free water, and a plant operated by Hess Corporation ("Hess Plant"), which dehydrates the gas to remove water vapor and then removes liquefiable hydrocarbons, termed Plant Btu Reduction ("PBR") entrained in the natural gas stream. Gas from the Hess Plant can be delivered to an interconnection with Sabine and Henry Hub or travel approximately two miles downstream to the compressor station at Erath. There, gas is compressed to enable its entry into the storage field and other interconnected pipelines: Gulf South, Sonat, Texas Gas, Trunkline, Columbia Gulf, Bridgeline and Jefferson Island Storage.

Q. Please explain the selection of the Base Period and Test Period in this filing.

A. The Base Period in this filing is the twelve months ended February 28, 2007. The Base Period data has been adjusted to reflect known and measurable changes in revenues and costs for the nine-month period ending November 30, 2007 ("Adjustment Period").

The Base Period, as adjusted in this manner, is referred to in Sea Robin's filing and testimony as the "Test Period".

Q. What is the overall Cost of Service utilized by Sea Robin in this filing?

A. Sea Robin has filed a cost of service totaling $ 21,999,861, as shown on Exhibit No. SR-15 and discussed in Mr. Biediger's testimony.

Q. What rate design methodology is utilized by Sea Robin?

A. Sea Robin continues to utilize the Straight Fixed Variable rate design methodology which it utilized in its last rate case filing. In addition, Sea Robin is utilizing the same gathering and transmission rate areas for rate design purposes which it utilized in its last rate case filing, as shown in the testimony of Mr. Grygar.

Q. When was the last Sea Robin rate proceeding?

A. Sea Robin's last rate proceeding was in Docket No. RP95-167-000. Sea Robin filed a Cost and Revenue Study on September 16, 1996, which was subsequently consolidated with Sea Robin's filing to refunctionalize certain of its assets to non-jurisdictional gathering. Sea Robin updated and filed a Cost and Revenue Study on April 16, 2001 in Docket No. CP95-168-000 in compliance with Commission Orders dated December 15, 2000 and January 17, 2001.

Q. How were these consolidated proceedings resolved?

A. Sea Robin and its customers resolved the proceedings by entering into a Stipulation and Agreement which was filed January 16, 2002, and approved by a unanimous Commission order dated March 13, 2002, 98 FERC ¶ 61,263 (2002).

Q. How does the cost of service which was settled in 2002 compare to this filing?

A. The cost of service underlying the settlement rates in the CP95-168-000 proceeding was $20,961,729 as compared to the cost of service filed in this case of $ 21,999,861.

Q. What are the major reasons for the rate increase?

A. The main reason for the increase in gathering and transmission transportation rates is a decrease in contract demand levels and throughput since the CP95-168-000 Settlement in 2002.

Q. What impact does this decrease in contract demand levels and throughput have on overall system rates?

A. In addition to the decrease in firm contract demand levels and interruptible throughput, the overall competitive position of the pipeline has resulted in greater discounts to retain contracted transportation on the system. The associated discount adjustments, when coupled with the decreased billing determinants levels, have resulted in higher reservation and usage rates for both gathering and transmission. The rates for both are shown in Schedule J-2, as further discussed in Mr. Grygar's testimony.

Q. Do you have an exhibit that shows the tariff sheets which state the proposed rates?

A. Yes. My Exhibit No. SR-3 includes copies of the tariff sheets which set forth the proposed rates for Sea Robin's transportation services.

Fuel Retention

Q. Has Sea Robin made adjustments to the fuel rates on the system?

A. No. Sea Robin reviewed the fuel usage, as well as loss and unaccounted for, experienced on the system, system flow characteristics, and expected flows based on contract volumes and capacity, and has determined that the current fuel rate of 0.65% is still the appropriate fuel retention rate for the operation of Sea Robin's system.

Capitalization and Return

Q. What capitalization is included in this filing?

A. Sea Robin has utilized the actual debt/equity levels of its parent, Panhandle Eastern Pipe Line Company, LP, as shown in Statement F-2, contained in my Exhibit No. SR-4.

Q. What is Panhandle's capital structure that has been utilized in this proceeding?

A. The most current data available is Panhandle's capital structure at April 30, 2007. Exhibit No. SR-4 compiles the debt capital and equity capital data from Panhandle's FERC books and records. As shown on Exhibit No. SR-4 the capital structure is as follows:

	Amount ($000)	Percentage
Debt	$ 717,428	39.85%
Equity	1,082,752	60.15
Total	$1,800,180	100.00%

Q. What cost of debt capital is Sea Robin proposing in this proceeding?

A. Panhandle's cost of debt capital is 6.51 percent. A schedule showing the current debt capital, cost of each issuance, and the amortization of costs associated with debt retirements is reflected in Exhibit No. SR-5. This cost of debt capital reflects a March 2007 refinancing.

Q. What return on equity is Sea Robin requesting in this filing?

A. Sea Robin proposes a return on equity of 13.50 percent. This level is consistent with the recommendations of Mr. Hevert in his Exhibit No. SR- 44. Given the elevated risk factors facing Sea Robin, this return is clearly justified. This level is also consistent with the recent FERC authorized rates for pipeline expansion projects as well as the range of equity rates authorized by the Commission over a long history in pipeline rate filings. Attached as Exhibit No. SR-6 is a listing of certificate filings for pipeline expansions and the associated returns approved for those projects.

Q. Is the requested return on equity consistent with capital requirements, investor expectations, and risks?

A. Yes. The Commission has struggled with this issue. In the *Kern River* Case (117 FERC ¶ 61,077 (2006)), the Commission rejected the use of companies in the DCF calculations that were structured as master limited partnerships ("MLPs"). The basis was that a portion of the distributions to unit holders could be considered a return of capital as opposed to the payment of a dividend. However, the Commission recognized that a significant number of companies are utilizing an MLP structure, and in the *Mojave* Case (118 FERC ¶ 61,252 (2007)), invited parties to propose additional criteria for the use of MLPs in the DCF calculations as part of a proxy group.

As Mr. Hevert outlines, capital markets have valued MLP structures more favorably, and provided greater market valuations for such structures. As such, it is clear that investors have a preference for holding equity in a company structured as an MLP. With the recent decision of United States Court of Appeals for the DC Circuit in *ExxonMobil Oil Corporation vs. FERC* issued May 29, 2007, the issue of the appropriateness of the Commission allowing an income tax recovery for regulated operations held as MLPs, pursuant to the Commission policy statement (111 FERC 61,139 (2005)) has eliminated a potential cost recovery uncertainty of placing regulated operations within MLP structures. As such, there seems to be significant support for allowing MLPs into a determination of an appropriate return calculation.

Q. What is the overall return for Sea Robin?

A. The overall average cost of capital is 10.71 percent. The derivation is included in Exhibit No. SR-4. The weighted average cost of capital reflects Sea Robin's parent's current capital structure at April 30, 2007.

Q. Does Sea Robin consider this overall return to be reasonable?

A. Yes. Sea Robin operates in a very competitive environment, and is subject to substantial risks that do not enable it to earn its allowed return. Such factors are discussed at length later in my testimony. In addition, Sea Robin's rate base reflects recent capital investment as a result of repairs due to damages sustained during the 2005 hurricane season, specifically with Hurricane Katrina and Hurricane Rita. The rate base filed in Sea Robin's 2002 Settlement was $39.1 million. The rate base reflected in this filing, as shown on Exhibit No. SR-16 in Mr. Biediger's testimony, is $51.8 million.

Q. Has Sea Robin made any changes in its basic rate design underlying its current rates?

A. No. Sea Robin has maintained its current Straight Fixed Variable ("SFV") rate design, and updated the rates for the cost of service levels, with appropriate allocations between transportation rate areas to reflect changes in system utilization. Sea Robin has maintained its current rate structure.

Q. Is Sea Robin currently recovering its cost of service?

A. No. As shown on Exhibit No. SR-37 of Mr. Grygar's testimony, Sea Robin's current revenues represent an undercollection of approximate $13.5 million compared to Sea Robin's $21,999,861 million cost of service. Sea Robin in particular is experiencing deterioration in the markets in which it operates due in large part to reduced gas supplies, which has manifested itself in intense competition among service providers, deep discounting of transportation rates, and an unwillingness by customers to commit to long-term contracts or firm transportation service.

Q. How have these factors been reflected in the volumes moving on the Sea Robin system?

A. As shown in Exhibit No. SR-43 in Mr. Grygar's testimony, Sea Robin has not been successful contracting for volumes to transport on a firm basis. In addition, the overall volumes on the system have been declining. Exhibit No. SR-7 contains a graph and table showing the decline in overall throughput on Sea Robin since 2000, as well as a forecast of the volumes projected for 2007. While the volume for 2007 is higher than that in 2006, which was impacted by the loss of production from Hurricanes Katrina and Rita, it still shows a declining trend since 2000.

Q. How have these volume reductions been reflected in the rate calculations?

A. Attached as Exhibit No. SR-8 are the adjustments to reservation quantities and usage quantities that were utilized to calculate rates in this case. In order to arrive at Test

Period transportation volumes, a number of adjustments to actual quantities were made. Sea Robin included projected volumes for several new transportation agreements, and has adjusted expected volumes for recent interconnects. Those transportation agreements which terminated during the base period or were projected to terminate during the Test Period were eliminated. Similarly, volumes for transportation services which commenced during the Base Period were increased to reflect an annual projected throughput level.

Q. Are there other volume adjustments that should be made?

A. Yes. The Base Period volumes would normally be adjusted to reflect expected declining production levels from historically connected gas reserves. As previously discussed, historical production connected to the Sea Robin system has been in steep decline for several years. As noted, the overall 2007 volumes are expected to be somewhat higher than those for 2006 which were impacted by the hurricanes in late 2005. However, the overall decline can still be based on the data outlined in Exhibit No. SR-7.

Q. Were adjustments made to account for this expected decline?

A. No. While the data shows continued declines in reserves connected to Sea Robin in past periods, the overall large decline in volumes since the last rate case is leading to significant increases in rates. As such, Sea Robin has elected in this initial filing not to make further adjustments for expected declines. The effect of not making these volume adjustments now is to provide an initial filed rate in this proceeding that is extremely conservative.

Current Business Risks

Q. Please outline the general business risks faced by Sea Robin in its operations.

A. I will discuss the various factors that make Sea Robin a very risky operation. These factors include 1) lack of direct end-use markets, 2) offshore nature of the Sea Robin system, 3) high dependence on shallow Gulf of Mexico drilling, 4) declining production in the shallow water Gulf, 5) high number of competitors and available capacity which limits revenue opportunities, 6) primarily interruptible business providing recovery on a volumetric charge basis, 7) limited ability to attract interconnections with growing deepwater gas supplies, 8) higher projected operating costs due to hurricane related risk factors, and 9) limited opportunities from offshore LNG volume deliveries.

Q. Please describe generally the business environment in which Sea Robin operates.

A. Sea Robin transports gas for shippers which consist of producers and marketers desiring to move their gas from the production areas of offshore Louisiana to the interstate and intrastate pipeline grid near Erath, Louisiana. Sea Robin has no markets of its own and does not deliver gas to any distribution customers or end-users. The shippers' gas is processed and treated at Erath and then delivered to interstate and intrastate pipelines at Sea Robin's multiple delivery points located immediately downstream of the processing plants. From Sea Robin, shippers have the ability to have their gas delivered to the Henry Hub, which is located approximately one mile from Erath, through the Sabine delivery point. The other delivery points are with

Columbia Gulf, Gulf South, Sonat, Texas Gas, Trunkline, Bridgeline and Jefferson Island Storage.

Q. What is the impact on Sea Robin having no end-use markets connected to the system?

A. The result is that any producer transporting gas must pay the Sea Robin transport rate, and then an additional rate to transport on the downstream systems to access those markets. This results in multiple contract and operating requirements, which in many cases can be avoided if delivering from production platforms offshore directly into interstate owned systems that have large directly connected markets. This clearly places Sea Robin at a disadvantage when market access considerations are factors in the contract decisions for services.

Q. Are there other ways Sea Robin can be considered different from other natural gas transmission systems?

A. Yes. First, the bulk of Sea Robin's operations are focused offshore. Sea Robin competes offshore with a diverse group of companies, including large transmission systems, gathering companies, other comparable offshore transmission systems, and producer-owned jurisdictional and non-jurisdictional facilities.

Q. What type of risks does this operating structure generate for Sea Robin's business?

A. There are many factors that will limit Sea Robin's ability to recover its cost of service and earn its allowed return. As noted, Sea Robin does not have direct customers on its pipeline system. Sea Robin deliveries are into other interstate and intrastate pipelines.

This is a large competitive disadvantage, as other offshore competitors that are integrated into existing interstate systems generally offer pooling services for deliveries into their offshore systems, which makes aggregation and marketing of produced volumes to end-use markets much more efficient. Sea Robin can only transport gas to deliveries near Erath, at which point the volumes can be delivered into other system supply pools.

Q. What would it take for Sea Robin to access direct end-use markets?

A. Sea Robin would have to expand from its terminus near Erath further onshore to access end-use markets. This would require substantial new investment. In addition, all end-use markets within a reasonable distance to Erath are already served by other pipeline systems. In my opinion, there would be little interest in these markets for contracting with Sea Robin for transportation capacity at rates that would justify the needed expansion of the system.

Q. Are there any other differences?

A. Yes. As I mentioned above, unlike the large, integrated transmission systems, Sea Robin has no distribution or end-use customers. Sea Robin's customers are the producers and marketers operating in the Gulf of Mexico. Sea Robin competes for the business of these producers and marketers in the volatile, deregulated marketplace at the wellhead. Thus, the general business activities of Sea Robin are focused on the producers' drilling activities in the Gulf of Mexico as opposed to the natural gas requirements of local distribution companies or industrial end-users in market areas such as the midwest or the northeast.

Q. What is the outlook for such producer drilling activities in the shallow Gulf of Mexico?

A. In the offshore area, the investment in drilling is clearly moving into the deepwater portions of the Gulf of Mexico, where the discovered reserves are significantly larger, and the returns for the producers are better. Attached as Exhibit No. SR-9 is a report titled "Gulf of Mexico Oil and Gas Production Forecast: 2004-2013", published by the Minerals Management Service of the U. S. Department of the Interior ("MMS") in October 2004. This report shows the decline experienced in the gas production in the shallow Gulf area, as well as the continued decline in such production through 2013. This report was also published prior to the 2005 Hurricane Katrina and Hurricane Rita events, which had a further negative affect on offshore gas production in 2006. As can be seen from this report, production in the shallow Gulf is declining significantly, and such decline is expected to continue. Drilling is moving into the deepwater areas that are not connected to Sea Robin.

Q. Is this shallow Gulf gas production decline confirmed by other sources?

A. Yes. Attached as Exhibit SR-10 is a graph that forecast shallow water gas production from the Gulf of Mexico published by the Energy Information Administration in their Annual Energy Outlook 2007. This forecast shows a significant decline through 2013, and a more gradual decline through 2030. There is no period in which production volumes are expected to increase.

Q. What are the expectations for the deepwater Gulf of Mexico?

A. In a recent news release dated May 1, 2007, the MMS noted that the gas production from deepwater areas now account for 40 percent of gas produced in the Gulf of Mexico in 2006. With the strong interest in deepwater leases, this deepwater production will continue to expand as a percent of total Gulf production.

Q. What has been the effect of continued decline in shallow Gulf production, and the 2005 hurricanes, on producer investments?

A. In my opinion, such investment has been curtailed. In addition, it is clear that the results of increased costs in the shallow Gulf area, such as insurance, repairs, and service costs have led many producers to focus on other production areas. As an example, attached as Exhibit No. SR-11 is a recent news release from Newfield Exploration Company ("Newfield"). This release discusses Newfield's sale of its shallow water Gulf of Mexico reserves. In addition, in a June 18, 2007 Gas Daily article, Steve Campbell, Newfield's vice president of investor relations stated "... the Gulf of Mexico is not a growth region in the shallow water." Newfield did indicate that the deepwater Gulf area will continue to be a strong focus for the company.

Q. How does all this directly affect Sea Robin?

A. These trends result in less available newly drilled reserves available to the Sea Robin system, as well as all systems operating in these shallow water areas of the Gulf of Mexico. As such, the throughput volumes on Sea Robin have declined, and are expected to continue to decline. As shown in Exhibit SR-7 there is substantial decline in Sea Robin throughput from 2000-2006, as well as forecasted volumes for 2007. As can be seen, the decline in volumes was even greater in 2006 following the 2005 hurricanes. Sea Robin has forecast that 2007 may have higher volumes than 2006, but will still be in an overall declining manner when compared to prior years. Such declining volumes make it even more difficult for Sea Robin to earn its allowed rate of return.

Q. How does Sea Robin's level of business risk compare to the activities of other integrated transmission systems?

A. Sea Robin's business is directly impacted by the success or failure of the drilling activities occurring in and around its system over which it has no control. The difference between Sea Robin's offshore operations and other, market-focused transmission pipelines is that the revenue stream of Sea Robin is directly attributable to the available molecules of reserves produced on its system from one geographic area of the Gulf of Mexico. While other transmission facilities have production area facilities, their revenues are predominately generated from distribution companies and end-users in the market area. The large, integrated transmission systems do not depend, as Sea Robin does, on the transportation of gas supplies from a single production area for their direct source of revenue.

Q. Are there other impacts of the declines in available production in the shallow Gulf area?

A. Yes. As overall shallow Gulf production volumes decline, additional capacity is freed up on all competing systems. As a result, there is increased competitive pressure to connect what limited new reserves and production are developed in the area. This serves to keep transportation rates very low, and such competitive pressures are reflected in the fact that the majority of Sea Robin volumes are transported under discounted transactions. In addition, with the availability of excess capacity, most contracts are for interruptible service, because there is little chance of interruption based on lack of capacity.

Q. How has competition in the Gulf of Mexico affected Sea Robin's operations?

A. The presence of competition means that it is even more difficult to replace declining reserves, and such competition accentuates the risk of Sea Robin being unable to maintain its throughput at a level to allow it to recover its costs and earn a reasonable return.

Q. How does Sea Robin remain competitive in such an environment?

A. Sea Robin negotiates with producers that have potential prospects for connection to its system. In some cases, Sea Robin (like other pipelines with which it competes) has agreed to invest capital by installing all or a portion of the facilities necessary to connect the producer's platform. Consequently, connections to Sea Robin tend to be capital intensive, thereby generating additional risk for underrecovery. In addition to its capital investment, Sea Robin must also frequently offer discounts to shippers that have prospects which could be connected to another offshore pipeline system.

Q. Can all of the discounts granted to shippers on Sea Robin's system be attributed to competition?

A. Yes.

Q. Were any of the discounts included in this proceeding given to Sea Robin's affiliate(s)?

A. No.

Q. How does the competition for new reserves and production affect Sea Robin's business risks?

A. Such focus on the transportation of gas supplies as its primary business activity puts Sea Robin more at risk for the underrecovery of its fixed costs than the typical natural gas transmission company that serves end-use and distribution markets.

Q. What makes recovery of its fixed costs more difficult?

A. Recovery of fixed costs is more difficult for Sea Robin than other fully-integrated pipelines because Sea Robin is almost wholly dependent on volumetric throughput for such recovery. As shown on page 2, column (h) of Exhibit No. SR-41 in Mr. Grygar's testimony, only 5.9% of Sea Robin's revenues can be attributed to firm transportation contracts. Collection of revenues on an interruptible, volumetric basis is more volatile and has more risk associated with it than firm transportation revenues which are recovered from a reservation charge component.

Q. Why does recovery of revenues on a volumetric basis have more risk?

A. The objectives of Sea Robin's business require Sea Robin to continuously seek to replace production lost from declining reserves. If Sea Robin is unable to sustain connection of a high level of replacement reserves, then throughput will decline in correlation with the natural depletion of reserves on the system. This is clearly shown in the volume decline on Sea Robin reflected on Exhibit No. SR-7.

Q. How does the low percentage of revenues attributable to firm transportation affect Sea Robin?

A. Without significant long-term, firm transportation agreements, Sea Robin is essentially at total risk for the underrecovery of its fixed costs. Such fixed costs were intended by the Commission to be recovered through the Rate Schedule FTS reservation component under the standard straight fixed-variable rate design. Given Sea Robin's lack of firm contracts, however, it will not recover its fixed costs through the reservation component, and it must rely on its interruptible throughput for recovery of virtually all of its fixed costs.

Q. Are there any shippers that have requested contracts for more firm services?

A. No. Sea Robin's interruptible service is very reliable, and the system is not fully subscribed or capacity constrained. The interruptible service provided on Sea Robin's system is tantamount to firm service, and shippers do not regularly request firm service. Sea Robin has been unsuccessful in securing any new firm commitments without offering a substantial discount.

Q. How does the minimal amount of firm service on Sea Robin's system affect its business risks?

A. As stated above, the predominance of interruptible service puts Sea Robin at significant risk for undercollection of costs. Basically, the greater the dependence a pipeline has on its volumetric services to generate revenue, the greater the risk of underrecovery. Reliance on interruptible transportation makes Sea Robin's potential earnings extremely volatile and unpredictable. Consequently, Sea Robin is at risk not only for its return, but also for recovery of its gas plant investment and fixed O&M expenses.

Q. Why does Sea Robin expect to not be able to attract gas throughput from the production being developed in the deepwater area of the Gulf?

A. Sea Robin's system is in the western portion of the shallow water Gulf of Mexico area. Generally, the deepwater production has greater initial production volumes, which justify investments in pipeline infrastructure that can provide transportation to onshore points that access liquid marketing points that would not be available into Sea Robin. For these reasons, the economic drivers will not generate interest in interconnecting with Sea Robin.

Q. Does Sea Robin expect higher overall operating costs in the future?

A. Yes. Following Hurricanes Katrina and Rita in 2005, the cost of supply service contractors, inspection services, transportation services, and other services in the offshore area, as well as insurance costs, have risen dramatically. In my opinion, this trend will continue for the foreseeable future.

Q. Can Sea Robin expect increased volumes from LNG sources?

A. In 2004, Sea Robin interconnected with the offshore buoy system installed by Excelerate Energy, LLC ("Excelerate") called the Gulf Gateway Energy Bridge Deepwater Port. The construction of this offshore LNG port began in August 2004, and was completed in February 2005. As part of this project, Excelerate interconnected with Sea Robin and contracted, on an interruptible basis, to transport revaporized LNG to pipeline interconnects in the Erath, Louisiana area. Excelerate also interconnected with the Blue Water Pipeline system to have another outlet for their revaporized LNG. As such, Sea Robin cannot expect that all, or part, of any Excelerate LNG cargoes will be transported via its system. Attached as Exhibit No. SR-12 is a description of Excelerate's Gulf Gateway Energy Bridge Deepwater Port from its website.

Q. Are there other reasons these LNG volumes may not be available to Sea Robin in the future?

A. Yes. Excelerate has received authorization to construct a similar offshore buoy LNG delivery system in an area approximately 13 miles off the coast of Massachusetts. Attached as Exhibit No. SR-13 is a description of Excelerate's Northeast Gateway Energy Bridge Deepwater Port from its website. In addition, Algonquin Gas Transmission, LLC has received authorization in Docket No. CP05-383-000 to construct a lateral from its system to the Excelerate offshore LNG port location to receive such revaporized LNG. This offshore system is expected to be completed by the end of 2007. Given the large margin difference between gas delivered in the Gulf Coast area and gas delivered in the market area in Massachusetts, the current economics will dictate that LNG cargoes will be delivered in Massachusetts up to the total capacity of that terminal. As such, while the installation in the offshore Gulf proved the viability of this offshore LNG terminal buoy system, such volumes in the longer term can be expected to be delivered in the northeast.

Q. Does this complete your prepared direct testimony?

A. Yes, it does.

The State of Texas}
} SS.
County of Harris }

BEFORE ME, the undersigned authority, on this day personally appeared Michael T. Langston, who being by me first duly sworn, on oath deposes and says:

That he is the Michael T. Langston, offering the foregoing prepared direct testimony and that all statements of fact contained therein are true and correct to the best of his knowledge, information and belief.

Michael T. Langston

Subscribed and sworn to before me this 27th day of June, 2007.

Suzanne Samano
Notary Public

My Commission Expires:

April 6, 2010 .

NON-INTERNET PUBLIC INFORMATION

Exhibit No. SR-2, Detailed System Map, has been designated as Non-Internet Public ("NIP"), and as such has been removed and filed under separate tab as "Non-Internet Public".

Public access to this document is available through the Public Reference Room at the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426, email address, public.referenceroom@ferc.gov.

Sea Robin Pipeline Company, LLC

CURRENTLY EFFECTIVE RATES

Each rate set forth in this Tariff is the currently effective rate pertaining to the particular rate schedule to which it is referenced, but each such rate is separate and independent and the change in any such rate shall not thereby effect a change in any other rate or rate schedule.

	Base Rate Per Dth	Adjustments Sec. 21	Maximum Rate Per Dth	Minimum Rate Per Dth	Fuel Reimbursement
	(1)	(2)	(3)	(4)	(5)
RATE SCHEDULE FTS					
Transmission					
Reservation Rate	$ 8.8234	-	$ 8.8234	-	-
Usage Rate	0.0326	$ 0.0016	0.0342	$ 0.0342	Pro Rata Share
Overrun Rate (1)	0.2901	-	0.2901	-	-
Gathering Charge					
Reservation Rate	$ 2.8389		$ 2.8389	-	
Overrun Rate (1)	0.0933		0.0933	-	

(1) Maximum firm volumetric rate applicable for capacity release

Issued by: Michael T. Langston
Sr. Vice President
Issued on: June 29, 2007

Effective: August 1, 2007

CURRENTLY EFFECTIVE RATES

Each rate set forth in this Tariff is the currently effective rate pertaining to the particular rate schedule to which it is referenced, but each such rate is separate and independent and the change in any such rate shall not thereby effect a change in any other rate or rate schedule.

Shipper shall pay either A or B, as applicable, under this Rate Schedule FTS-2:

	Base Rate Per Dth (1)	Adjustments Sec. 21 (2)	Maximum Rate Per Dth (3)	Minimum Rate Per Dth (4)	Fuel Reimbursement (5)
RATE SCHEDULE FTS-2					
Transmission					
A. Volumetric Rate	$ 0.3227	$ 0.0016	$ 0.3243	$ 0.0342	Pro Rata Share
B. Reservation Rate	$ 8.8234	-	$ 8.8234	-	-
Usage Rate	0.0326	$ 0.0016	0.0342	$ 0.0342	Pro Rata Share
Overrun Rate (1)	0.2901	-	0.2901	-	-
Gathering Charge					
A. Volumetric Rate	$ 0.0933	-	$ 0.0933	-	-
B. Reservation Rate	$ 2.8389	-	$ 2.8389	-	-
Overrun Rate (1)	0.0933	-	0.0933	-	-

(1) Maximum firm volumetric rate applicable for capacity release.

CURRENTLY EFFECTIVE RATES

Each rate set forth in this Tariff is the currently effective rate pertaining to the particular rate schedule to which it is referenced, but each such rate is separate and independent and the change in any such rate shall not thereby effect a change in any other rate or rate schedule.

	Base Rate Per Dth	Adjustments Sec. 21	Maximum Rate Per Dth	Minimum Rate Per Dth	Fuel Reimbursement
	(1)	(2)	(3)	(4)	(5)
RATE SCHEDULE IIS					
Transmission					
Usage Rate	$ 0.3227	$ 0.0016	$ 0.3243	$ 0.0342	Pro Rata Share
Gathering					
Usage Rate	$ 0.0933	-	$ 0.0933	-	-

CURRENTLY EFFECTIVE RATES

Each rate set forth in this Tariff is the currently effective rate pertaining to the particular rate schedule to which it is referenced, but each such rate is separate and independent and the change in any such rate shall not thereby effect a change in any other rate or rate schedule.

	Maximum Rate Per Dth	Minimum Rate Per Dth
RATE SCHEDULE GPS		
Daily Parking Rate	$ 0.3227	$ 0.0000

SEA ROBIN PIPELINE COMPANY, LLC

Resulting Return on Common Equity
From Overall Rate of Return Claimed
For the Period Ending April 30, 2007, As Adjusted

Line No.	Description (a)	Capitalization 1/ (b)	Ratio (c)	Cost (d)	Weighted Rate (e)	Return Component (f)	Rate of Return on Equity (g)
1	Overall Rate of Return Claimed					10.71%	
2	Debt	$ 717,428	39.85%	6.51%	2.59%	-	
3	Common Equity	1,082,752	60.15%	13.50%	8.12%		13.50%
4	Total	$ 1,800,180	100.00%				

1/ Capitalization shown is Sea Robin's parent company, Panhandle Eastern Pipe Line Company, LP's capitalization.

SEA ROBIN PIPELINE COMPANY, LLC

Rate of Return Claimed

The total return included in Sea Robin Pipeline Company, LLC's ("Sea Robin") cost of service shown in Statements A and B herein are based on a rate of return of 13.50% applied to the net investment rate base for the period ending February 28, 2007, as adjusted. Sea Robin is an indirect wholly-owned subsidiary of Panhandle Eastern Pipe Line Company, LP ("Panhandle"). As such, Sea Robin has utilized the capitalization of Panhandle. As shown on Statement F-2, Sea Robin's capitalization is comprised of 39.85 percent debt and 60.15 percent equity as of April 30, 2007, Panhandle's most recently available.

The position of Sea Robin is that the allowed fair rate of return must reflect investor return requirements under current competitive market conditions. Sea Robin's transportation services are directly impacted by the success or failure of the drilling activities in and around its system. This primary business activity places Sea Robin at significant risk for the recovery of its fixed costs. A rate of return level of 13.50% is required to enable Sea Robin to maintain and attract the capital necessary for economical operations without impairment of the committed invested capital.

SEA ROBIN PIPELINE COMPANY, LLC

Preferred Stock Capital

Not applicable. Sea Robin Pipeline Company, LLC has no preferred stock outstanding as of February 28, 2007.

SEA ROBIN PIPELINE COMPANY, LLC

Debt Capital

Sea Robin has utilized the long-term debt outstanding of its parent, Panhandle Eastern Pipe Line Company, LP, as of April 30, 2007, the latest data available.

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STATEMENT F-3
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PANHANDLE EASTERN PIPE LINE COMPANY, LP

Weighted Average Cost of Debt Capital

Line No.	Description (a)	Term Note Due 7/15/2009 (b)	Senior Note Due 7/15/2029 (c)	Senior Note Due 4/1/2010 (d)	Senior Note Due 8/15/2008 (e)	Senior Note Due 8/15/2013 (f)	Total (n)	Amortization of Gain/Loss on Reacquired Debt (k)	Net (l)	F/N ID
1	Nominal Date of Issue	3-29-1999	3-29-1999	3-27-2000	8-18-2003	8-18-2003				
2	Date of Maturity	7-15-2009	7-15-2029	4-1-2010	8-15-2008	8-15-2013				
3	Interest Rate	6.50%	7.00%	8.25%	4.80%	6.05%				
4	Principal Amount of Issue (Gross Proceeds)	$ 60,623,000	$ 66,305,000	$ 40,500,000	$ 300,000,000	$ 250,000,000	$ 717,428,000		$ 717,428,000	
5	Underwriter's Discount or Commission	$ 143,873	$ 1,048,407	$ 74,737	$ 362,612	$ 993,060	$ 2,622,689		$ 2,622,689	
6	Underwriter's Costs as % of Gross Proceeds	0.24%	1.58%	0.18%	0.12%	0.40%				
7	Issuance Expense	$ 217,367	$ 1,176,767	$ 13,192	$ 723,681	$ 1,420,249	$ 3,551,256		$ 3,551,256	
8	Issuance Expense as % of Gross Proceeds	0.36%	1.77%	0.03%	0.24%	0.57%				
9	Debt Loss Upon Retirement							$ 15,227,668	$ 15,227,668	
10	Net Proceeds (L4 - L5 - L7)	$ 60,261,760	$ 64,079,825	$ 40,412,072	$ 298,913,707	$ 247,586,690	$ 711,254,055	$ 15,227,668	$ 726,481,723	
11	Net Proceeds Per Unit ($100) (L9 / L4)	99.40	96.64	99.78	99.64	99.03				
12	Term of Issue (Years)	10	30	10	5	10				
13	Remaining Term for Debt Discounts/Expenses	2.38	22.38	3.00	1.46	6.46				
14	Cost of Money (Yield to Maturity)	6.75%	7.15%	8.27%	5.05%	6.20%				
15	Debt Outstanding at 12-31-2006	$ 60,623,000	$ 66,305,000	$ 40,500,000	$ 300,000,000	$ 250,000,000	$ 717,428,000	$ -	$ 717,428,000	
16	Debt Due Within One Year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
17	Debt Less Current Maturities (L15 - L16)	$ 60,623,000	$ 66,305,000	$ 40,500,000	$ 300,000,000	$ 250,000,000	$ 717,428,000	$ -	$ 717,428,000	
18	Annual Cost of Debt	$ 4,092,596	$ 4,740,799	$ 3,350,043	$ 15,144,887	$ 15,498,674	$ 42,826,998	$ 3,878,404	$ 46,705,403	
19	Weighted Average Cost of Debt on Issuance Principal	6.75%	7.15%	8.27%	5.05%	6.20%	5.97%		6.51%	

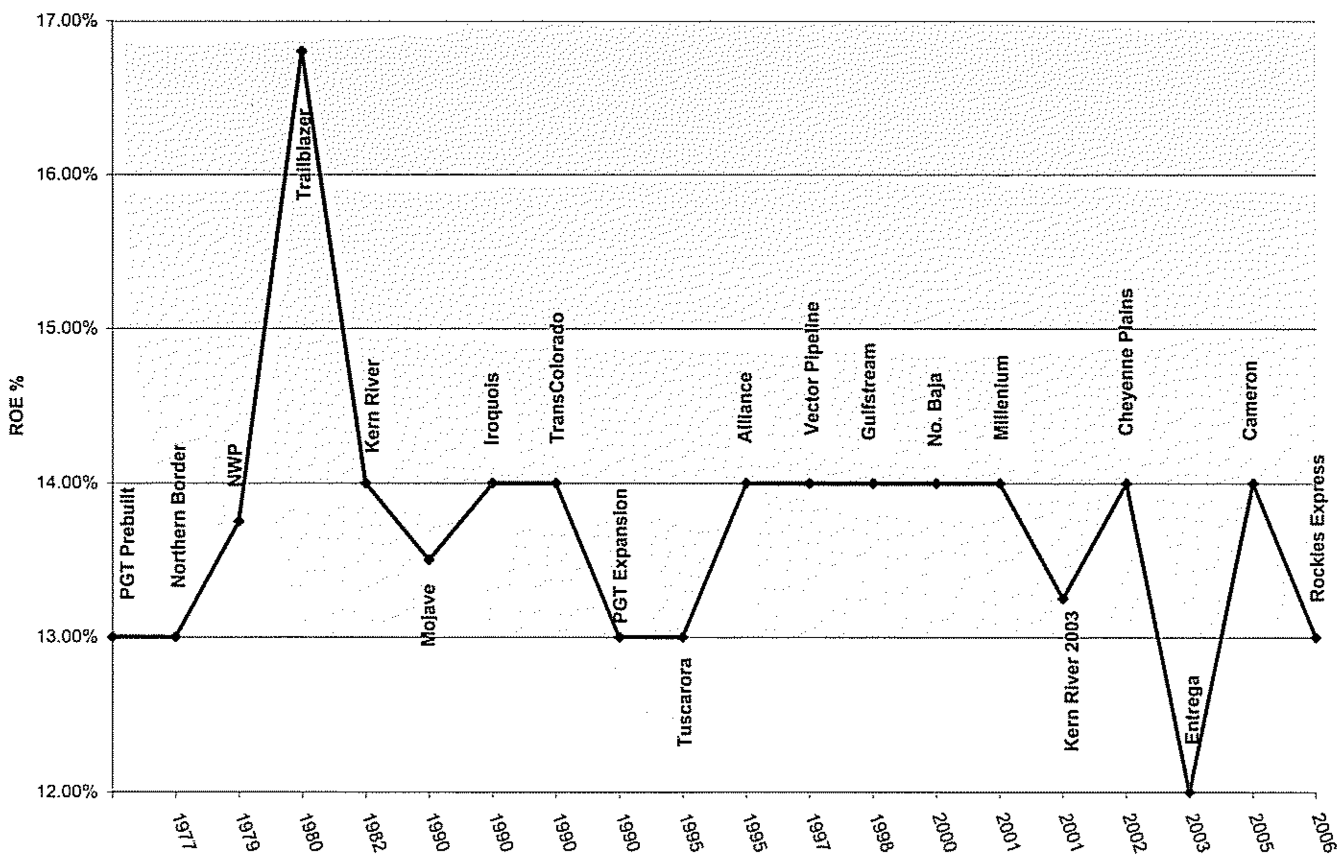
PANHANDLE EASTERN PIPE LINE COMPANY, LP

Amortization of Loss on Reacquired Debt

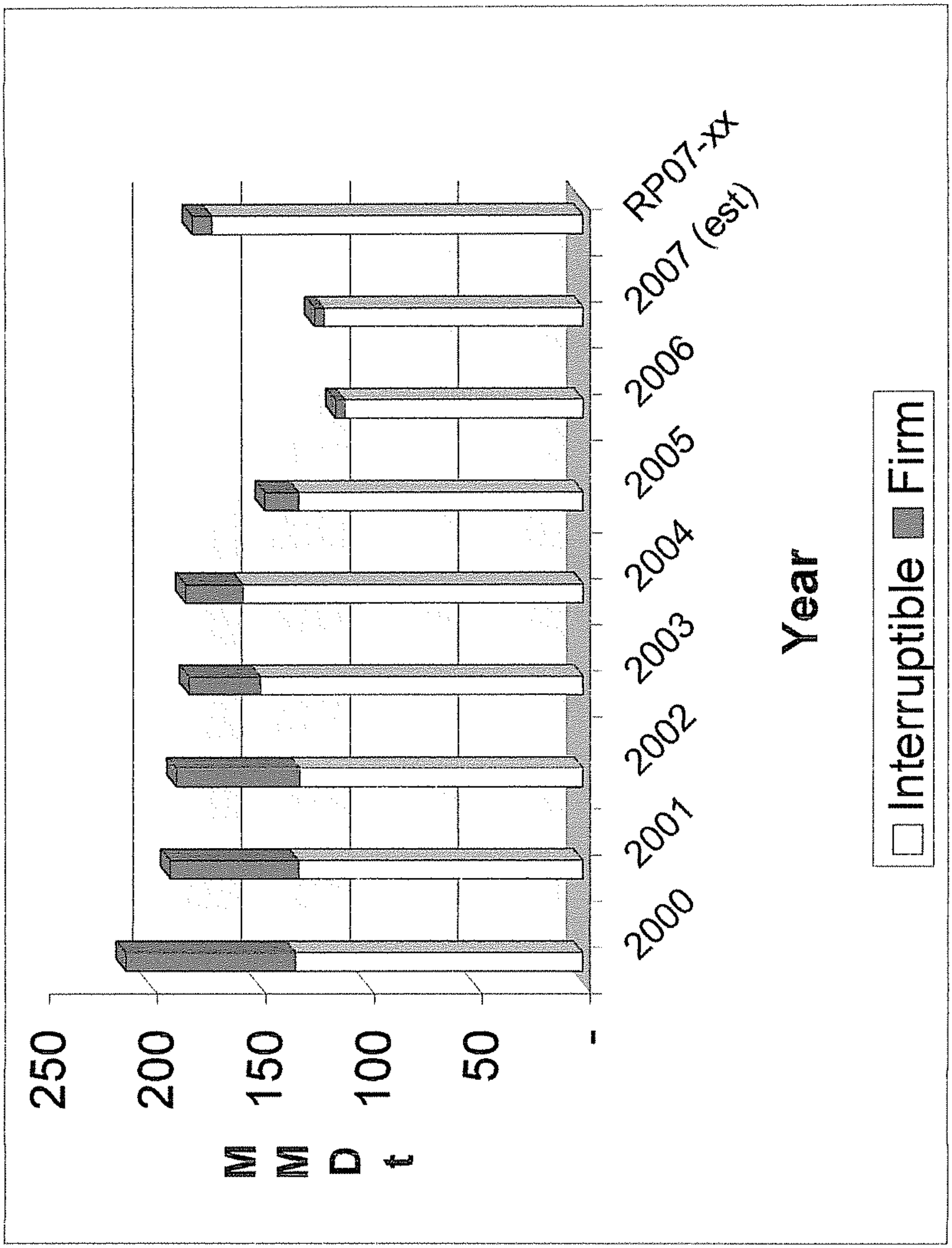
Line No.	Description (a)	10.375% Debentures Due 2011 (b)	8.25% Debentures Due 2010 (c)	6.50% Debentures Due 2009 (d)	7.95% Debentures Due 2023 (e)	7.20% Debentures Due 2024 (f)	7% Debentures Due 2029 (g)	Total (h)
1	Nominal Date of Issue	3/1/1999	6/12/2003	6/12/2003	12/15/2001	12/15/2001	08/19/2003	
2	Date of Maturity	11/1/2011	4/01/2010	7/15/2009	3/15/2023	8/15/2024	7/15/2029	
3	Interest Rate	10.375%	8.25%	6.50%	7.95%	7.20%	7.00%	
4	Principal Amount of Issue (Gross Proceeds)	$ 100,000,000	$ 59,500,000	$ 139,377,000	$ 100,000,000	$ 100,000,000	$ 233,695,000	
5	Underwriter's Discount or Commission							
6	Underwriter's Costs as % of Gross Proceeds							
7	Issuance Expense							
8	Issuance Expense as % of Gross Proceeds							
9	Debt Loss upon Retirement	$ 2,018,069	$ 2,938,205	$ 4,020,709	$ 3,807,470	$ 1,518,634	$ 924,581	$ 15,227,668
10	Net Proceeds (L4 - L5 - L7)	$ 97,981,931	$ 56,561,795	$ 135,356,291	$ 96,192,530	$ 98,481,366	$ 232,770,419	
11	Term of Issue (Years) - Remaining	4.33	2.75	2.04	15.71	17.13	22.04	
12	Cost of Money (Yield to Maturity)	-	-	-	-	-	-	
13	Debt Outstanding at 12-31-2006	$ -	$ -	$ -	$ -	$ -	$ -	
14	Amortization of Loss on Reacquired Debt	$ 466,067	$ 1,068,438	$ 1,970,936	$ 242,360	$ 88,653	$ 41,950	$ 3,878,404

Order Date	Return on Equity	Order Date	Docket No.
1977	13.00%	7/8/1977	RP75-57
1979	13.00%	6/8/1979	CP78-124
1980	13.75%	6/13/1980	CP79-56
1982	16.80%	3/12/1982	CP79-80
1990	14.00%	1/24/1990	CP89-2047
1990	13.50%	1/24/1990	CP89-2048
1990	14.00%	7/30/1990	CP86-523
1990	14.00%	12/20/1990	CP90-1777
1995	13.00%	1/12/1995	CP93-618
1995	13.00%	4/4/1995	CP93-685
1997	14.00%	8/1/1997	CP97-168
1998	14.00%	10/19/1998	CP98-131
2000	14.00%	4/28/2000	CP00-6
2001	14.00%	5/18/2001	CP01-22
2001	14.00%	12/19/2001	CP98-150
2002	13.25%	2/27/2002	CP02-422
2003	14.00%	10/22/2003	CP03-301
2005	12.00%	8/9/2005	CP04-413
2006	14.00%	5/22/2006	CP02-378
2006	13.00%	12/31/2006	CP06-354

ROE Certificate Filings for the Past 30 Years



SEA ROBIN PIPELINE COMPANY, LLC
COMPARISON OF ACTUAL THROUGHPUT
2000-2006



SEA ROBIN PIPELINE COMPANY, LLC

Comparison of Actual Throughput
For the Period 2001 - 2006

Line No.	Year	Volumes - MMDt		
		Firm	Interruptible	Total
	(a)	(b)	(c)	(d)
1	2000	78	133	211
2	2001	59	132	191
3	2002	57	131	188
4	2003	33	149	182
5	2004	27	157	184
6	2005	16	132	147
7	2006	4	110	115
8	2007 (est)	4	120	124
9	RP07-xx	9	171	181

Source: FERC Form 2

SEA ROBIN PIPELINE COMPANY, LLC

Adjustments to
Gathering - Reservation Volumes - MMBtu
Twelve Months Ended February 28, 2007, As Adjusted

Line No.	Rate Schedule/ Contract	Shipper	Reservation Quantities (MMBtu) (a)	Adjustment No. 1 1/ (b)	Adjustment No. 2 2/ (c)	Reservation Quantities As Adjusted (MMBtu) (d)
		Rate Schedule FTS				
1	FTS-1078	BP America Production Company	87,500	(87,500)	-	-
2	FTS-1584	Louis Dreyfus Energy Services, L.P.	147,000	-	-	147,000
3	FTS-1075	Superior Natural Gas Corporation	4,080	(4,080)	-	-
4		Total Rate Schedule FTS	238,580	(91,580)	-	147,000
		Rate Schedule FTS-2				
5	FTS-2-1643	Hess Corporation	-	-	171,600	171,600
6		Total Rate Schedule FTS-2	-	-	171,600	171,600
7		Total Gathering - Reservation Volumes, As Adjusted	238,580	(91,580)	171,600	318,600

1/ Reflects termination of Shipper agreement as per contract.
2/ Reflects annualized quantitiy for Contracts projected to commence after the Base Period.

SEA ROBIN PIPELINE COMPANY, LLC

Adjustments to
Transmission - Reservation Volumes - MMBtu
Twelve Months Ended February 28, 2007, As Adjusted

Line No.	Rate Schedule/ Contract	Shipper	Reservation Quantities (MMBtu) (a)	Adjustment No. 1 1/ (b)	Adjustment No. 2 2/ (c)	Reservation Quantities As Adjusted (MMBtu) (d)
		Rate Schedule FTS				
1	FTS-1078	BP America Production Company	87,500	(87,500)	-	-
2	FTS-1584	Louis Dreyfus Energy Services, L.P	147,000	-	-	147,000
3	FTS-1075	Superior Natural Gas Corporation	4,080	(4,080)	-	-
4		Total Rate Schedule FTS	238,580	(91,580)	-	147,000
		Rate Schedule FTS-2				
5	FTS-2-1643	Hess Corporation	-	-	171,600	171,600
6		Total Rate Schedule FTS-2	-	-	171,600	171,600
7		Total Gathering - Reservation Volumes, As Adjusted	238,580	(91,580)	171,600	318,600

1/ Reflects termination of Shipper agreement as per contract.
2/ Reflects annualized quantitiy for Contracts projected to commence after the Base Period.

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SEA ROBIN PIPELINE COMPANY, LLC

Adjustments to
Transmission - Usage Volumes - MMBtu
Twelve Months Ended February 28, 2007, As Adjusted

Line No.	Rate Schedule/ Contract	Shipper	Usage Quantities (MMBtu)	Adjustment No. 1 1/	Adjustment No. 2 2/	Adjustment No. 3 3/	Usage Quantities As Adjusted (MMBtu)
			(a)	(b)	(c)	(d)	(e)
		Rate Schedule FTS					
1	FTS-1078	BP America Production Company	-	-	-	-	-
2	FTS-1584	Louis Dreyfus Energy Services, L.P.	3,989,922	-	-	-	3,989,922
3	FTS-1075	Superior Natural Gas Corporation	120,781	(120,781)	-	-	-
4		Total Rate Schedule FTS	4,110,703	(120,781)	-	-	3,989,922
		Rate Schedule FTS-2					
5	FTS-2-1643	Hess Corporation	-	-	-	5,219,500	5,219,500
6		Total Rate Schedule FTS-2	-	-	-	5,219,500	5,219,500
		Rate Schedule ITS					
		Current Attachments					
7	ITS-1000	Adams Resources Marketing, Ltd	285,302	-	-	-	285,302
8	ITS-1281	Apache Corporation	8,633,323	-	-	-	8,633,323
9	ITS-1284	Apache Corporation	120,664	-	-	-	120,664
10	ITS-1330	Apache Corporation	(1)	1	-	-	-
11	ITS-1536	Apex Oil & Gas, Inc.	346,118	-	-	-	346,118
12	ITS-1544	Arena Energy, LLC	2,824,407	-	2,824,407	-	5,648,814
13	ITS-1080	BP America Production Company	64,835	-	-	-	64,835
14	ITS-1046	Burlington Resources Trading Inc.	20,739	(20,739)	-	-	-
15	ITS-1044	Burlington Resources Trading Inc.	107,327	(107,327)	-	-	-
16	ITS-1013	Chevron U.S.A. Inc.	2,741,788	-	-	-	2,741,788
17	ITS-1115	Chevron U.S.A. Inc.	17,887,195	-	-	5,475,000	23,362,195
18	ITS-1332	Chevron U.S.A. Inc.	121,677	-	-	-	121,677
19	ITS-1033	ConocoPhillips Company	4,326,122	-	-	-	4,326,122
20	ITS-1618	ConocoPhillips Company	-	-	-	-	-

Exhibit No. SR-8
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Schedule G-3(b)
Page 2

SEA ROBIN PIPELINE COMPANY, LLC

Adjustments to
Transmission - Usage Volumes - MMBtu
Twelve Months Ended February 28, 2007, As Adjusted

Line No.	Rate Schedule/ Contract	Shipper	Usage Quantities (MMBtu)	Adjustment No. 1 1/	Adjustment No. 2 2/	Adjustment No. 3 3/	Usage Quantities As Adjusted (MMBtu)
			(a)	(b)	(c)	(d)	(e)
21	ITS-1032	Devon Energy Production Company, LP	925,143	-	-	-	925,143
22	ITS-1087	Devon Energy Production Company, LP	9,183,520	-		2,920,000	12,103,520
23	ITS-1334	Devon Energy Production Company, LP	3,855	-	-	-	3,855
24	ITS-1015	Dominion Exploration & Production, Inc.	271,688	-	-	-	271,688
25	ITS-1178	Dominion Exploration & Production, Inc.	31,391	-	-	-	31,391
26	ITS-1297	El Paso E&P Company, L.P.	3,006,010	-	-	-	3,006,010
27	ITS-1302	El Paso E&P Company, L.P.	542,640	-	-	-	542,640
28	ITS-1024	Energy Resource Technology GOM, Inc.	79,750	-	-	-	79,750
29	ITS-1200	Energy Resource Technology GOM, Inc.	459,614	-	-	-	459,614
30	ITS-1355	Energy Resource Technology GOM, Inc.	23,588	-	-	-	23,588
31	ITS-1561	Enjet, Inc.	3,386,646	-	-	-	3,386,646
32	ITS-1382	Excelerate Gas Marketing, L.L.C.	304,072	-	-	2,500,000	2,804,072
33	ITS-1397	Excelerate Gas Marketing, L.L.C.	18,658	-	-	-	18,658
34	ITS-1340	Exxon Mobil Corporation	145	-	-	-	145
35	ITS-1096	ExxonMobil Gas & Power Marketing Company	686,556	-	-	-	686,556
36	ITS-1111	ExxonMobil Gas & Power Marketing Company	5,146,666	-	-	-	5,146,666
37	ITS-1235	Gil Energy, Inc.	36,592	-	-	-	36,592
38	ITS-1364	Hess Corporation	1,241	-	-	-	1,241
39	ITS-1504	Houston Exploration Company (The)	974,515	-	-	-	974,515
40	ITS-1314	Houston Exploration Company (The)	55,160	-	-	-	55,160
41	ITS-1278	Hunt Chieftan Development, LP	224,086	-	-	-	224,086
42	ITS-1279	Hunt Chieftan Development, LP	25,629	-	-	-	25,629
43	ITS-1510	Hunt Oil Company	3,612,462	-	-	-	3,612,462
44	ITS-1511	Hunt Oil Company	333,445	-	-	-	333,445
45	ITS-1010	Hunt Petroleum (AEC), Inc.	153,826	-	-	-	153,826
46	ITS-1236	Hunt Petroleum (AEC), Inc.	989,285	-	-	-	989,285
47	ITS-1344	Hunt Petroleum (AEC), Inc.	3,696	-	-	-	3,696
48	ITS-1551	Integrys Energy Services, Inc.	948,521	-	-	-	948,521
49	ITS-1275	Kerr-McGee (Nevada) LLC	-	-	-	-	-
50	ITS-1216	Kerr-McGee Oil & Gas Corporation	276,973	-	-	-	276,973
51	ITS-1276	Kerr-McGee Oil & Gas Onshore LP	-	-	-	-	-
52	ITS-1260	Louis Dreyfus Energy Services, L.P.	5,812,334	-	-	-	5,812,334
53	ITS-1296	Louis Dreyfus Energy Services, L.P.	686,029	-	-	-	686,029
54	ITS-1290	Magnum Hunter Production Inc.	589,602	-	-	-	589,602

SEA ROBIN PIPELINE COMPANY, LLC

Adjustments to
Transmission - Usage Volumes - MMBtu
Twelve Months Ended February 28, 2007, As Adjusted

Line No.	Rate Schedule/ Contract	Shipper	Usage Quantities (MMBtu)	Adjustment No. 1 1/	Adjustment No. 2 2/	Adjustment No. 3 3/	Usage Quantities As Adjusted (MMBtu)
			(a)	(b)	(c)	(d)	(e)
55	ITS-1385	Magnum Hunter Production Inc.	77,805	-	-	-	77,805
56	ITS-1308	Maritech Resources, Inc.	8,266	-	-	-	8,266
57	ITS-1029	McMoran Oil & Gas LLC	756,115	-	-	-	756,115
58	ITS-1131	McMoran Oil & Gas LLC	3,750,637	-	-	-	3,750,637
59	ITS-1182	Meridian Resource & Exploration Company, The	25,388	-	-	-	25,388
60	ITS-1346	Merit Energy Company	10	-	-	-	10
61	ITS-1248	Merit Energy Company	85,851	-	-	-	85,851
62	ITS-1239	Merit Energy Company	-	-	-	730,000	730,000
63	ITS-1191	Mieco Inc.	2,075,895	-	-	-	2,075,895
64	ITS-1600	Minerals Management Service	3,526,241	-	7,052,482	-	10,578,723
65	ITS-1611	Minerals Management Service	279,980	-	-	-	279,980
66	ITS-1031	Newfield Exploration Company	575,840	-	-	-	575,840
67	ITS-1347	Newfield Exploration Company	12,349	-	-	-	12,349
68	ITS-1592	Nippon Oil Exploration U.S.A. Limited	173,494	-	-	-	173,494
69	ITS-1073	Noble Energy Marketing, Inc.	5,932,807	-	-	-	5,932,807
70	ITS-1040	Noble Energy, Inc.	117,146	-	-	-	117,146
71	ITS-1349	Noble Energy, Inc.	17,085	(17,085)	-	-	-
72	ITS-1377	Northstar Gulfsands, LLC	4,675	-	-	-	4,675
73	ITS-1381	Northstar Gulfsands, LLC	7,754	-	-	-	7,754
74	ITS-1610	Offshore Shelf LLC	13,197	-	-	-	13,197
75	ITS-1039	Pogo Producing Company	25,071	-	-	-	25,071
76	ITS-1354	Pogo Producing Company	1,675	-	-	-	1,675
77	ITS-1038	Pogo Producing Company	436,455	-	-	-	436,455
78	ITS-1515	Seneca Resources Corporation	1,169,952	-	-	-	1,169,952
79	ITS-1295	Sequent Energy Management, L.P.	2,284,517	-	-	-	2,284,517
80	ITS-1527	Sequent Energy Management, L.P.	-	-	-	-	-
81	ITS-1400	Shoreline Gas, Inc.	749,658	-	-	-	749,658
82	ITS-1549	Shoreline Gas, Inc.	2,624,197	-	-	-	2,624,197
83	ITS-1205	Sojitz Energy Venture, Inc.	147,196	-	-	-	147,196
84	ITS-1374	Southwest Energy, L.P.	1,176,715	-	-	-	1,176,715
85	ITS-1363	Stone Energy Corporation	13,285	-	-	-	13,285

SEA ROBIN PIPELINE COMPANY, LLC

Adjustments to
Transmission - Usage Volumes - MMBtu
Twelve Months Ended February 28, 2007, As Adjusted

Line No.	Rate Schedule/ Contract	Shipper	Usage Quantities (MMBtu)	Adjustment No. 1 1/	Adjustment No. 2 2/	Adjustment No. 3 3/	Usage Quantities As Adjusted (MMBtu)
			(a)	(b)	(c)	(d)	(e)
86	ITS-1082	Superior Natural Gas Corporation	13,024,945	-	-	-	13,024,945
87	ITS-1165	Superior Processing Service Corporation	69,710	-	-	-	69,710
88	ITS-1196	Taylor Energy Company	-	-	-	-	-
89	ITS-1570	Trammo Petroleum, Inc.	187,176	(187,176)	-	-	-
90	ITS-1583	United Energy Trading, LLC	406,067	-	203,034	-	609,101
91	ITS-1269	W & T Offshore Inc	231,520	-	-	-	231,520
92		Total Current Attachments	116,261,508	(332,326)	10,079,923	11,625,000	137,634,105
		New Attachments					
93	EI 333B	Devon Energy Production Company, LP	-	-	-	6,375,455	6,375,455
94	EI 330	Devon Energy Production Company, LP	-	-	-	2,234,165	2,234,165
95	EC 195	Fairways - multiple shippers	-	-	-	1,593,955	1,593,955
96	SMI 128	Garden Banks - multiple shippers	-	-	-	14,340,120	14,340,120
97	J Leg	Multiple shippers	-	-	-	5,261,840	5,261,840
98	WC 580	Newfield Exploration Company	-	-	-	1,149,020	1,149,020
99	EC 206	Tana Exploration Company, LLC	-	-	-	1,149,020	1,149,020
100	SMI 27	Taylor Energy Company	-	-	-	1,593,955	1,593,955
101		Total New Attachments	-	-	-	33,697,530	33,697,530
102		Total Rate Schedule ITS	116,261,508	(332,326)	10,079,923	45,322,530	171,331,635
103		Total Transmission - Usage Volumes, As Adjusted	120,372,211	(453,107)	10,079,923	50,542,030	180,541,057

1/ Adjustment to reflect termination of Shipper agreements as per contract.
2/ Adjustment to annualize contracts commencing in the Base Period.
3/ Adjustment to annualize contracts commencing in the Test Period.

SEA ROBIN PIPELINE COMPANY, LLC

Adjustments to
Gathering - Usage Volumes - MMBtu
Twelve Months Ended February 28, 2007, As Adjusted

Line No.	Rate Schedule/ Contract	Shipper	Usage Quantities (MMBtu) (a)	Adjustment No. 1 1/ (b)	Adjustment No. 2 2/ (c)	Adjustment No. 3 3/ (d)	Usage Quantities As Adjusted (MMBtu) (e)
		Rate Schedule ITS					
		Current Attachments					
1	ITS-1281	Apache Corporation	8,682,352	-	-	-	8,682,352
2	ITS-1284	Apache Corporation	139,584	-	-	-	139,584
3	ITS-1080	BP America Production Company	66,376	-	-	-	66,376
4	ITS-1046	Burlington Resources Trading Inc.	23,601	(23,601)	-	-	-
5	ITS-1044	Burlington Resources Trading Inc.	108,974	(108,974)	-	-	-
6	ITS-1013	Chevron U.S.A. Inc.	7,597	-	-	-	7,597
7	ITS-1115	Chevron U.S.A. Inc.	63,956	-	-	5,475,000	5,538,956
8	ITS-1033	ConocoPhillips Company	4,226,021	-	-	-	4,226,021
9	ITS-1618	ConocoPhillips Company	2,352	-	-	-	2,352
10	ITS-1032	Devon Energy Production Company, LP	1,015,478	-	-	-	1,015,478
11	ITS-1087	Devon Energy Production Company, LP	9,232,357	-	-	2,920,000	12,152,357
12	ITS-1334	Devon Energy Production Company, LP	-	-	-	-	-
13	ITS-1015	Dominion Exploration & Production, Inc.	260,690	-	-	-	260,690
14	ITS-1178	Dominion Exploration & Production, Inc.	31,331	-	-	-	31,331
15	ITS-1024	Energy Resource Technology GOM, Inc.	80,444	-	-	-	80,444
16	ITS-1200	Energy Resource Technology GOM, Inc.	394,048	-	-	-	394,048
17	ITS-1561	Enjet, Inc.	3,415,485	-	-	-	3,415,485
18	ITS-1096	ExxonMobil Gas & Power Marketing Company	705,098	-	-	-	705,098
19	ITS-1111	ExxonMobil Gas & Power Marketing Company	5,107,001	-	-	-	5,107,001
20	ITS-1235	Gil Energy, Inc.	28,549	-	-	-	28,549
21	ITS-1364	Hess Corporation	-	-	-	-	-
22	ITS-1504	Houston Exploration Company (The)	972,432	-	-	-	972,432
23	ITS-1314	Houston Exploration Company (The)	51,038	-	-	-	51,038
24	ITS-1278	Hunt Chieftan Development, LP	210,618	-	-	-	210,618
25	ITS-1279	Hunt Chieftan Development, LP	27,248	-	-	-	27,248
26	ITS-1510	Hunt Oil Company	3,573,528	-	-	-	3,573,528
27	ITS-1511	Hunt Oil Company	368,903	-	-	-	368,903
28	ITS-1010	Hunt Petroleum (AEC), Inc.	173,198	-	-	-	173,198
29	ITS-1236	Hunt Petroleum (AEC), Inc.	1,006,016	-	-	-	1,006,016
30	ITS-1344	Hunt Petroleum (AEC), Inc.	3,510	-	-	-	3,510
31	ITS-1551	Integrys Energy Services, Inc.	974,748	-	-	-	974,748
32	ITS-1216	Kerr-McGee Oil & Gas Corporation	281,965	-	-	-	281,965
33	ITS-1260	Louis Dreyfus Energy Services, L.P.	5,818,037	-	-	-	5,818,037
34	ITS-1296	Louis Dreyfus Energy Services, L.P.	667,582	-	-	-	667,582
35	ITS-1290	Magnum Hunter Production Inc.	606,403	-	-	-	606,403
36	ITS-1385	Magnum Hunter Production Inc.	87,732	-	-	-	87,732
37	ITS-1239	Merit Energy Company	-	-	-	730,000	730,000
38	ITS-1191	Mieco Inc.	2,077,837	-	-	-	2,077,837
39	ITS-1600	Minerals Management Service	3,550,313	-	7,100,626	-	10,650,939

SEA ROBIN PIPELINE COMPANY, LLC

Adjustments to
Gathering - Usage Volumes - MMBtu
Twelve Months Ended February 28, 2007, As Adjusted

Line No.	Rate Schedule/ Contract	Shipper	Usage Quantities (MMBtu) (a)	Adjustment No. 1 1/ (b)	Adjustment No. 2 2/ (c)	Adjustment No. 3 3/ (d)	Usage Quantities As Adjusted (MMBtu) (e)
40	ITS-1611	Minerals Management Service	278,997	-	-	-	278,997
41	ITS-1031	Newfield Exploration Company	577,728	-	-	-	577,728
42	ITS-1592	Nippon Oil Exploration U.S.A. Limited	68,251	-	-	-	68,251
43	ITS-1073	Noble Energy Marketing, Inc.	5,526,733	-	-	-	5,526,733
44	ITS-1040	Noble Energy, Inc.	84,642	-	-	-	84,642
45	ITS-1349	Noble Energy, Inc.	14,846	(14,846)	-	-	-
46	ITS-1377	Northstar Gulfsands, LLC	9,042	-	-	-	9,042
47	ITS-1381	Northstar Gulfsands, LLC	20,670	-	-	-	20,670
48	ITS-1610	Offshore Shelf LLC	13,592	-	-	-	13,592
49	ITS-1039	Pogo Producing Company	31,037	-	-	-	31,037
50	ITS-1354	Pogo Producing Company	114	-	-	-	114
51	ITS-1038	Pogo Producing Company	431,137	-	-	-	431,137
52	ITS-1515	Seneca Resources Corporation	1,165,858	-	-	-	1,165,858
53	ITS-1295	Sequent Energy Management, L.P.	2,345,635	-	-	-	2,345,635
54	ITS-1527	Sequent Energy Management, L.P.	482	-	-	-	482
55	ITS-1374	Southwest Energy, L.P.	1,180,806	-	-	-	1,180,806
56	ITS-1363	Stone Energy Corporation	19,382	-	-	-	19,382
57	ITS-1082	Superior Natural Gas Corporation	13,021,952	-	-	-	13,021,952
58	ITS-1165	Superior Processing Service Corporation	68,890	-	-	-	68,890
59	ITS-1196	Taylor Energy Company	4,882	-	-	-	4,882
60	ITS-1570	Trammo Petroleum, Inc.	173,392	(173,392)	-	-	-
61	ITS-1583	United Energy Trading, LLC	368,660	-	184,330	-	552,990
62	ITS-1269	W & T Offshore Inc	307,783	-	-	-	307,783
63		Total Current Attachments	79,756,913	(320,813)	7,284,956	9,125,000	95,846,056
		New Attachments					
64	EI 333B	Devon Energy Production Company, LP	-	-	-	6,375,455	6,375,455
65	EI 330	Devon Energy Production Company, LP	-	-	-	2,234,165	2,234,165
66	EC 195	Fairways - multiple shippers	-	-	-	1,593,955	1,593,955
67	SMI 128	Garden Banks - multiple shippers	-	-	-	14,340,120	14,340,120
68	J Leg	Multiple shippers	-	-	-	5,261,840	5,261,840
69	WC 580	Newfield Exploration Company	-	-	-	1,149,020	1,149,020
70	EC 206	Tana Exploration Company, LLC	-	-	-	1,149,020	1,149,020
71	SMI 27	Taylor Energy Company	-	-	-	1,593,955	1,593,955
72		Total New Attachments	-	-	-	33,697,530	33,697,530
73		Total Rate Schedule ITS	79,756,913	(320,813)	7,284,956	42,822,530	129,543,586
74		Total Gathering - Usage Volumes, As Adjusted	79,756,913	(320,813)	7,284,956	42,822,530	129,543,586

1/ Adjustment to reflect termination of Shipper agreements as per contract.
2/ Adjustment to annualize contracts commencing in the Base Period.
3/ Adjustment to annualize contracts commencing in the Test Period.

Exhibit No. SR-9
Page 1
Docket No. RP07-___-000

Gulf of Mexico Oil and Gas Production Forecast: 2004-2013

MMS U. S. Department of the Interior
Minerals Management Service
Gulf of Mexico OCS Region

ERRATA

This report went to press before Hurricane Ivan passed through the Gulf of Mexico, causing significant damage to several facilities and pipelines. The 2004 production estimates, therefore, should be reduced by at least 27 million barrels of oil and 110 billion cubic ft of gas (cumulative shut-in production as of November 1, 2004). For example, Table 2 shows the forecast total oil production in 2004 is 1,562,000 barrels of oil per day, which equates to an estimated 570 million barrels of oil produced in 2004. As of November 1, 2004, however, this estimate should be reduced to 543 million barrels of oil.

Cover: The Na Kika semisubmersible gathers production from six subsea projects in the deepwater Gulf of Mexico. Na Kika was installed by Shell and operated by BP (photo courtesy of BP)

Gulf of Mexico

Oil and Gas Production Forecast:

2004 – 2013

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Richie D. Baud
Angela G. Boice
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Thierry DeCort
Richard Desselles
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U.S. Department of the Interior
Minerals Management Service
Gulf of Mexico OCS Region

New Orleans
October 2004

Contents

Table of Abbreviations

BCFPD	billion cubic ft per day
GOM	Gulf of Mexico
MMBOE	million barrels of oil equivalent
MMBOPD	million barrels of oil per day
MMS	Minerals Management Service
OCS	Outer Continental Shelf
TVD	true vertical depth

Introduction

This report provides a daily oil and gas production rate forecast for the Gulf of Mexico (GOM) Outer Continental Shelf (OCS) for the years 2004 through 2013. The forecast shows average daily oil and gas production estimates for each calendar year.

In this report, daily oil production rates include both oil and condensate production, and daily gas production rates include both associated and non-associated gas production. A "deepwater" project is defined as one with a production facility located in a water depth equal to or greater than 1,000 ft (305 m). Note that the water depth of a subsea project, or that of an undeveloped project, refers to the deepest water depth of a well within that project.

The methodology of this report differs from that of previous editions (e.g., Melancon et al., 2003), which were based primarily on surveys of deepwater operators. The older reports are comparable to the second section of this report. Sections III and IV have been added to extend the forecast further into the future, to capture the potential of recently announced discoveries that have not yet been sanctioned, and to include the potential from undiscovered projects that may come online within the forecast period.

This report refers to various deepwater development "projects." In most cases, the project names and their lateral extents are defined by operators. Hydrocarbon accumulations that are developed via a common surface facility or a common subsea system are typically considered to be a single project. Note that previous editions of this report (e.g., Melancon et al., 2003) referred to deepwater development "fields" instead of "projects." Field names are assigned by the Minerals Management Service (MMS) to a lease or a group of leases so that natural gas and oil resources, reserves, and production can be allocated on the basis of the unique geologic feature that contains the hydrocarbon accumulation.

This report is divided into four sections. The first section presents historical production trends. The second section outlines our 5-year forecast, which is based primarily on a survey of deepwater operators. The third section extends this forecast out to 10 years on the basis of additional, industry-announced discoveries not reported to MMS in the operator survey. The fourth section adds potential production from "yet to find" deepwater projects, on the basis of analyses of historical discovery and production trends in the GOM.

Section I - Historical Production

The divisions used throughout this report are illustrated in Figure 1. Projects in less than 1,000 ft (305 m) water depths are considered to be shallow-water projects and those in greater than 1,000 ft (305 m) are considered to be deepwater projects. For gas production, the shallow water is further subdivided according to the true vertical depth (TVD) of the producing zones and the water depth. The "shallow-water deep" zone refers to gas production from well completions that are at or below 15,000 ft (4,572 m) TVD subsea and in water depths less than 656 ft (200 meters). All other shallow-water completions are referred to as part of the "shallow-water shallow" zone.

Figures 2a-c and 3a-c show historic daily production rates for the shallow- and deepwater GOM from 1990 through 2003. The portion of shallow-water gas production that came from well completions deeper than 15,000 ft (4,572 m) TVD and water depths less than 656 ft (200 m) is also shown. This shallow-water deep-gas trend is the subject of recent royalty incentives and increased activity.

The 2003 production volumes have been estimated using the data available at the time of this writing (mid 2004). The certainty of our forecast beyond 2003 is based, in part, on the accuracy of this 2003 estimate.

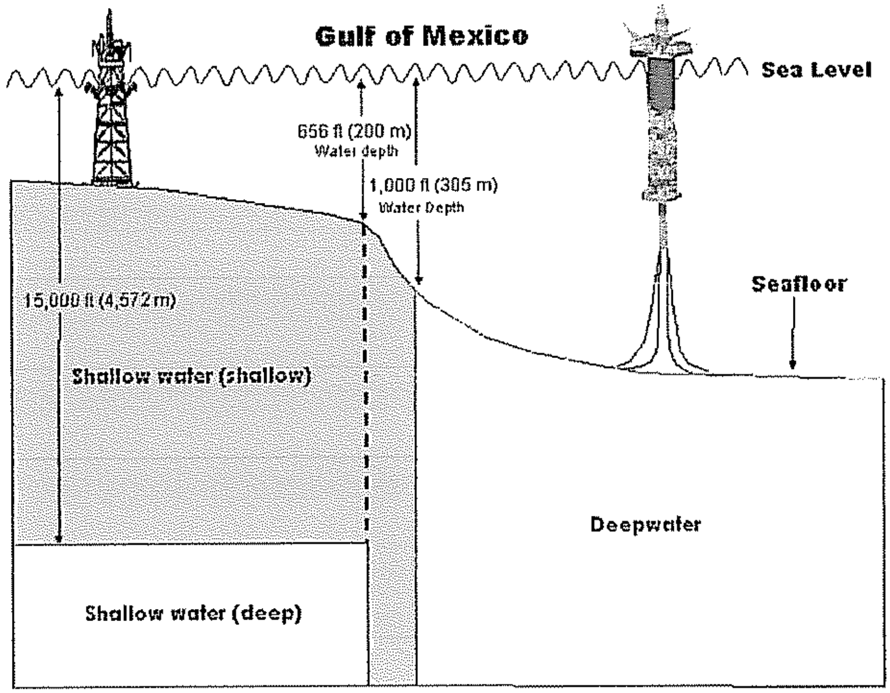
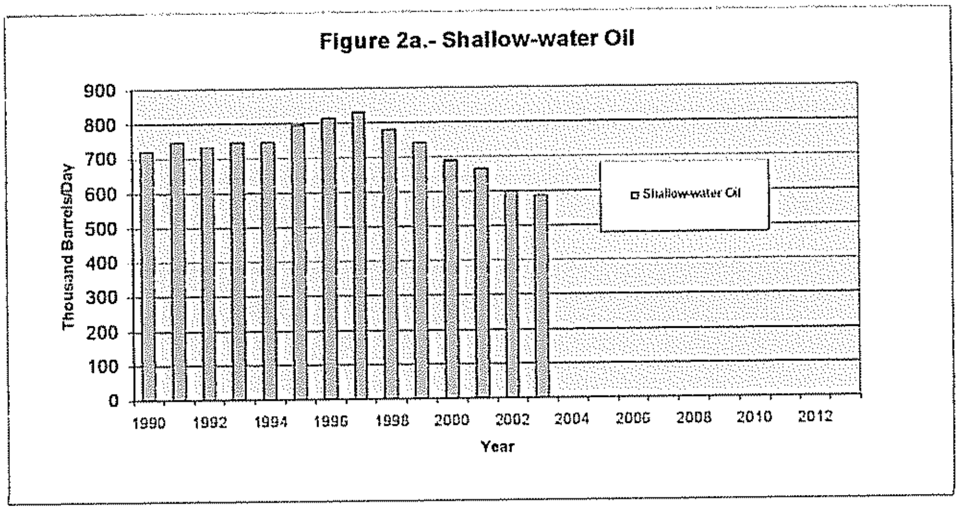
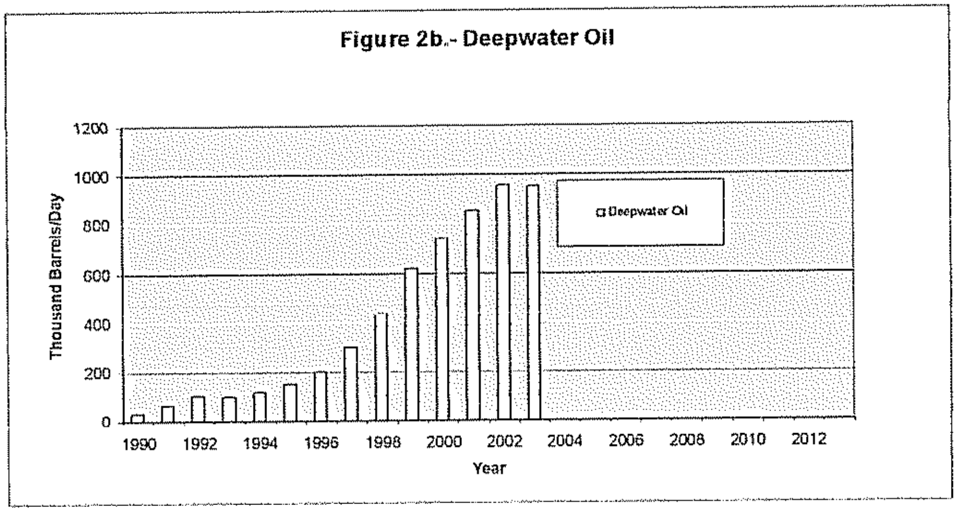


Figure 1. Water-depth and completion-depth divisions.

Section II – Short-term Forecast

Most of the Gulf's oil production and a significant portion of the Gulf's gas production come from the deepwater area. Deepwater GOM operators were surveyed in order to facilitate our short-term production forecast. Operators were asked to provide actual 2003 production volumes and the projected rates for all deepwater projects online or planned to come online before yearend 2008. The names and startup years of the publicly releasable projects are shown in Table 1.





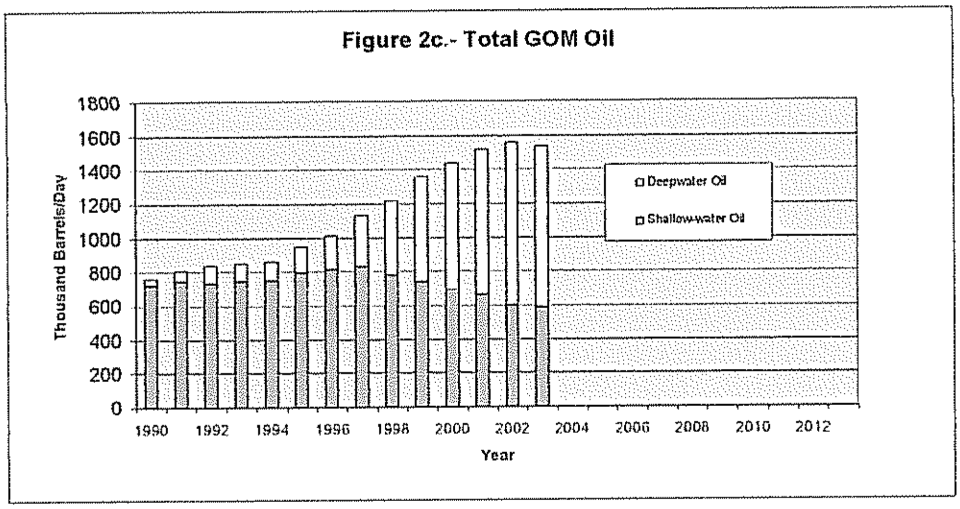


Figure 2. – Historic oil production rates.

Figure 3a.- Shallow-water Gas

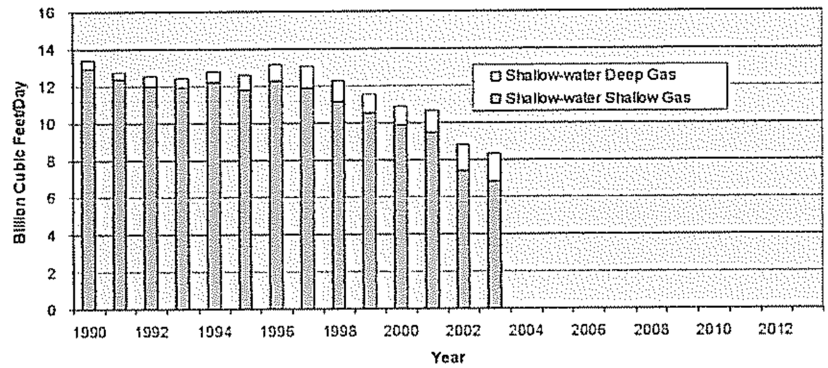


Figure 3b.- Deepwater Gas

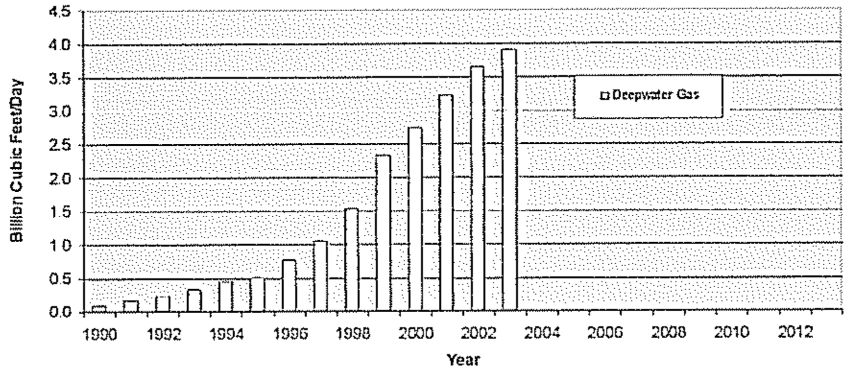


Figure 3c.- Total GOM Gas

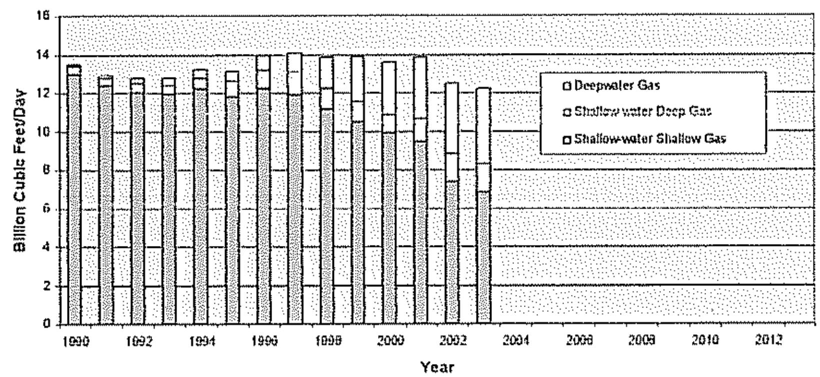


Figure 3. – Historic gas production rates.

Table 1 - Development Systems of Productive Deepwater GOM Projects

Year of First Production	Project Name[2]	Operator	Block	Water Depth (ft)	System Type	DWRR[3]
1979	Cognac	Shell	MC 194	1,023	Fixed Platform	
1984	Lena	ExxonMobil	MC 280	1,000	Compliant Tower	
1988[1]	GC 29	Placid	GC 29	1,554	Semisubmersible/ Subsea	
1988[1]	GC 31	Placid	GC 31	2,243	Subsea	
1989	Bullwinkle	Shell	GC 65	1,353	Fixed Platform	
1989	Jolliet	ConocoPhillips	GC 184	1,760	TLP	
1991	Amberjack	BP	MC 109	1,100	Fixed Platform	
1992	Alabaster	ExxonMobil	MC 485	1,438	Subsea	
1993[1]	Diamond	Kerr McGee	MC 445	2,095	Subsea	
1993	Zinc	ExxonMobil	MC 354	1,478	Subsea	
1994	Auger	Shell	GB 426	2,860	TLP	
1994	Pompano/ Pompano II	BP	VK 989	1,290	Fixed Platform/ Subsea	
1994	Tahoe/SE Tahoe	Shell	VK 783	1,500	Subsea	
1995[1]	Cooper	Newfield	GB 388	2,600	Semisubmersible	
1995	Shasta	ChevronTexaco	GC 136	1,048	Subsea	
1995	VK 862	Walter	VK 862	1,043	Subsea	
1996	Mars	Shell	MC 807	2,933	TLP/Subsea	
1996	Popeye	Shell	GC 116	2,000	Subsea	
1996	Rocky	Shell	GC 110	1,785	Subsea	
1997	Mensa	Shell	MC 731	5,318	Subsea	
1997	Neptune	Kerr McGee	VK 826	1,930	Spar/Subsea	
1997	Ram-Powell	Shell	VK 956	3,216	TLP	
1997	Troika	BP	GC 200	2,721	Subsea	
1998	Arnold	Marathon	EW 963	1,800	Subsea	
1998	Baldpate	Amerada Hess	GB 260	1,648	Compliant Tower	
1998	Morpeth	Eni	EW 921	1,696	TLP/Subsea	
1998	Oyster	Marathon	EW 917	1,195	Subsea	
1999	Allegheny	Eni	GC 254	3,294	TLP	
1999	Angus	Shell	GC 113	2,045	Subsea	
1999	Dulcimer	Mariner	GB 367	1,120	Subsea	Yes
1999	EW 1006	Walter	EW 1006	1,884	Subsea	
1999	Gemini	ChevronTexaco	MC 292	3,393	Subsea	
1999	Genesis	ChevronTexaco	GC 205	2,590	Spar	
1999	Macaroni	Shell	GB 602	3,600	Subsea	
1999	Penn State	Amerada Hess	GB 216	1,450	Subsea	
1999	Pluto	Mariner	MC 674	2,828	Subsea	Yes

Table 1 - Development Systems of Productive Deepwater GOM Projects *- continued*

Year of First Production	Project Name[2]	Operator	Block	Water Depth (ft)	System Type	DWRR[3]
1999	Ursa	Shell	MC 809	3,800	TLP	
1999	Virgo	TotalFinaElf	VK 823	1,130	Fixed Platform	Yes
2000	Black Widow	Mariner	EW 966	1,850	Subsea	Yes
2000	Conger	Amerada Hess	GB 215	1,500	Subsea	
2000	Diana	ExxonMobil	EB 945	4,500	Subsea	
2000	Europa	Shell	MC 935	3,870	Subsea	
2000	Hoover	ExxonMobil	AC 25	4,825	Spar	
2000	King	Shell	MC 764	3,250	Subsea	
2000	Marlin	BP	VK 915	3,236	TLP	
2000	Northwestern	Amerada Hess	GB 200	1,736	Subsea	Yes
2000	Petronius	ChevronTexaco	VK 786	1,753	Compliant Tower	
2001	Brutus	Shell	GC 158	3,300	TLP	
2001	Crosby	Shell	MC 899	4,400	Subsea	
2001	Einset	Shell	VK 872	3,500	Subsea	Yes
2001	EW 878	Walter	EW 878	1,585	Subsea	Yes
2001	Ladybug	ATP	GB 409	1,355	Subsea	
2001	Marshall	ExxonMobil	EB 949	4,376	Subsea	
2001	MC 68	Walter	MC 68	1,360	Subsea	
2001	Mica	ExxonMobil	MC 211	4,580	Subsea	
2001	Nile	BP	VK 914	3,535	Subsea	
2001	Oregano	Shell	GB 559	3,400	Subsea	
2001	Pilsner	Unocal	EB 205	1,108	Subsea	Yes
2001	Prince	El Paso	EW 1003	1,500	TLP	Yes
2001	Serrano	Shell	GB 516	3,153	Subsea	
2001	Typhoon	ChevronTexaco	GC 237	2,679	TLP	Yes
2002	Aconcagua	TotalFinaElf	MC 305	7,100	Subsea	Yes
2002	Aspen	BP	GC 243	3,065	Subsea	Yes
2002	Boomvang	Kerr McGee	EB 643	3,650	Spar	Yes
2002	Camden Hills	Marathon	MC 348	7,216	Subsea	Yes
2002	Horn Mountain	BP	MC 127	5,400	Spar	Yes
2002	King	BP	MC 84	5,000	Subsea	
2002	King Kong	Mariner	GC 472	3,980	Subsea	Yes
2002	King's Peak	BP	DC 133	6,845	Subsea	Yes
2002	Lost Ark	Samedan	EB 421	2,960	Subsea	Yes
2002	Madison	ExxonMobil	AC 24	4,856	Subsea	
2002	Manatee	Shell	GC 155	1,939	Subsea	Yes
2002	Nansen	Kerr McGee	EB 602	3,675	Spar	Yes
2002	Navajo	Kerr McGee	EB 690	4,210	Subsea	Yes

Table 1 - Development Systems of Productive Deepwater GOM Projects *- continued*

Year of First Production	Project Name[2]	Operator	Block	Water Depth (ft)	System Type	DWRR[3]
2002	Princess	Shell	MC 765	3,600	Subsea	
2002	Sangria	Spinnaker	GC 177	1,487	Subsea	Yes
2002	Tulane	Amerada Hess	GB 158	1,054	Subsea	Yes
2002	Yosemite	Mariner	GC 516	4,150	Subsea	Yes
2003	Boris	BHP	GC 282	2,378	Subsea	Yes
2003	East Anstey/ Na Kika	Shell	MC 607	6,590	FPS/Subsea[4]	
2003	Falcon	Pioneer	EB 579	3,638	Subsea	Yes
2003	Fourier/ Na Kika	Shell	MC 522	6,950	FPS/Subsea[4]	
2003	Gunnison	Kerr McGee	GB 668	3,100	Spar	Yes
2003	Habanero	Shell	GB 341	2,015	Subsea	
2003	Herschel/ Na Kika	Shell	MC 520	6,739	FPS/Subsea[4]	
2003	Matterhorn	TotalFinaElf	MC 243	2,850	TLP	Yes
2003	Medusa	Murphy	MC 582	2,223	Spar	Yes
2003	Pardner	Anadarko	MC 401	1,139	Subsea	
2003	Zia	Devon	MC 496	1,804	Subsea	
2004	Devil's Tower	Dominion	MC 773	5,610	Spar	
2004	Marco Polo	Anadarko	GC 608	4,320	TLP	
2004	Holstein	BP	GC 644	4,344	Spar	
2004	Magnolia	Conocophilips	GB 783	4,674	TLP	
2004	Unreleasable					
2004	Red Hawk	Kerr-McGee	GB 877	5,334	Spar	
2004	Boomvang	Kerr-McGee	EB 598	3,650	Spar	
2004	Hack Wilson	Kerr-McGee	EB 599	3,650	Subsea	
2004	Front Runner	Murphy	GC 339	3,330	Spar	
2004	North Medusa	Murphy	MC 538	2,223	Subsea	
2004	Harrier	Pioneer	EB 759	4,114	Subsea	
2004	Tomahawk	Pioneer	EB 629	3,561	Subsea	
2004	Raptor	Pioneer	EB 668	3,788	Subsea	
2004	Ariel/Na Kika	Shell	MC 429	6,274	Subsea	
2004	Kepler/Na Kika	Shell	MC 383	5,800	Subsea	
2004	Coulomb/ Na Kika	Shell	MC 613	7,591	Subsea	
2004	Llano	Shell	GB 387	2,376	Subsea	

Table 1 - Development Systems of Productive Deepwater GOM Projects *- continued*

Year of First Production	Project Name[2]	Operator	Block	Water Depth (ft)	System Type	DWRR[3]
2004	Glider	Shell	GC 248	3,440	Subsea	
2005	K2 North	Anadarko	GC 518	4,049	Subsea	
2005	K2	ENI	GC 562	4,006	Subsea	
2005	Mad Dog	BP	GC 782	4,428	Spar	
2005	Thunder Horse	BP	MC 778	6,089	Semisubmersible	
2005	Unreleasable					
2005	Unreleasable					
2005	Triton	Dominion	MC 728	5,373		
2005	Rigel	Dominion	MC 252	5,225		
2005	17 Hands	Murphy	MC299	5,881	Subsea	
2006	Atlantis	BP	GC 699	6,133	Semisubmersible	
2006	Unreleasable					
2006	Balboa	Kerr-McGee	EB 597	3,352	Spar	
2008	Unreleasable					

[1] Indicates projects that are no longer on production.

[2] The previous edition of this report listed deepwater fields, whereas this version lists deepwater projects

[3] Indicates projects with one or more leases approved to receive Deep Water Royalty Relief

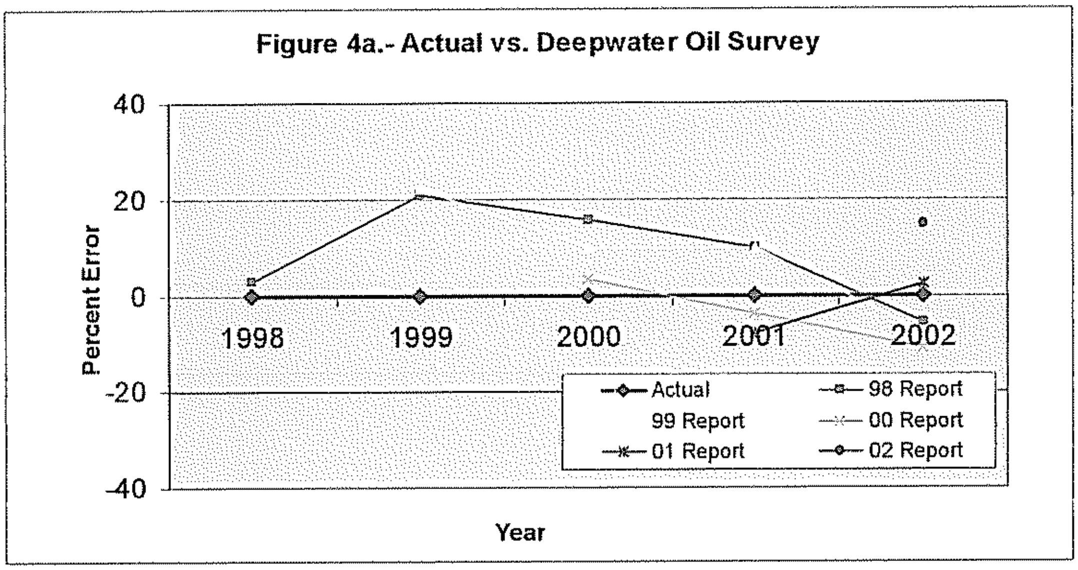
[4] Na Kika FPS is located in Mississippi Canyon Block 474 in 6,340 ft (1,932 m) of water.

AC = Alaminos Canyon
DC = De Soto Canyon
EB = East Breaks
EW = Ewing Bank
GB = Garden Banks
GC = Green Canyon
MC = Mississippi Canyon
VK = Viosca Knoll

This method of surveying operators to forecast production has been used quite successfully in previous editions of this report. Figures 4a and 4b show that GOM operators predicted their future production accurately. For example, the pink-colored line in Figure 4b shows that the 1998 survey predicted 2001 deepwater gas production within 11.5 percent of the actual volume and predicted 2002 deepwater gas production within 2.3 percent of the actual volume. The ability of operators to project future deepwater production accurately is especially significant, given the dramatic increases in deepwater production during this period. For example, deepwater gas production rose 140 percent from 1998 to 2002, and the 1998 survey predicted this increase within 2.3 percent of the actual volume. Not all estimates were this accurate, but they were all within 22 percent of the actual production and most were within 10 percent

Although previous editions of this report offered a high and low estimate for future deepwater production, this report provides the actual deepwater volumes from the operator survey with no error estimation added. Similarly, a single estimate (rather than a high and a low estimate) of shallow-water production is made for each of the next five years. The shallow-water deep gas production is projected by performing a linear regression on the historical production in this trend and extrapolating forward in time. Shallow-water oil and gas production (excluding the shallow-water deep-gas trend) is projected by fitting an exponential decline curve to the most recent period of sustained decline (1996-2003 for oil and 1996-2001 for gas), then assuming that future shallow-water production will decline at half this rate. This method results in a 6-percent exponential decline for shallow-water oil and a 6-percent exponential decline for shallow-water gas (excluding the shallow-water deep-gas trend).

Figures 5a-c through 6a-c show production estimates through 2008 based on the method described above. Table 1 lists the projects expected to begin production by yearend 2008, according to the operator survey.



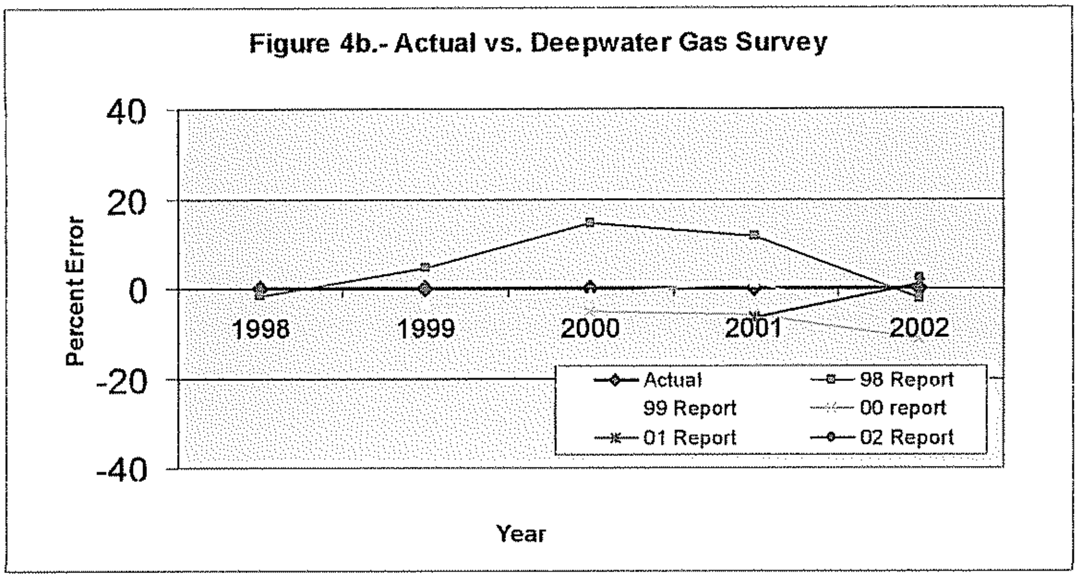
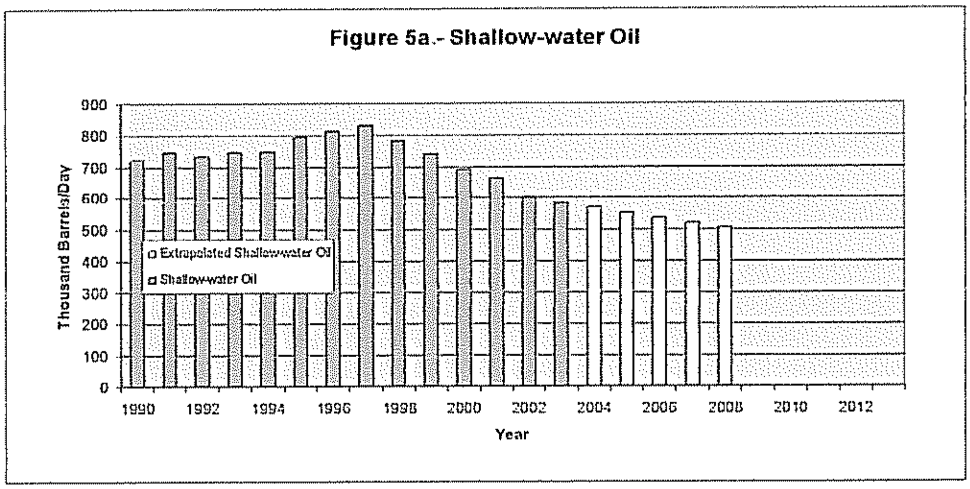
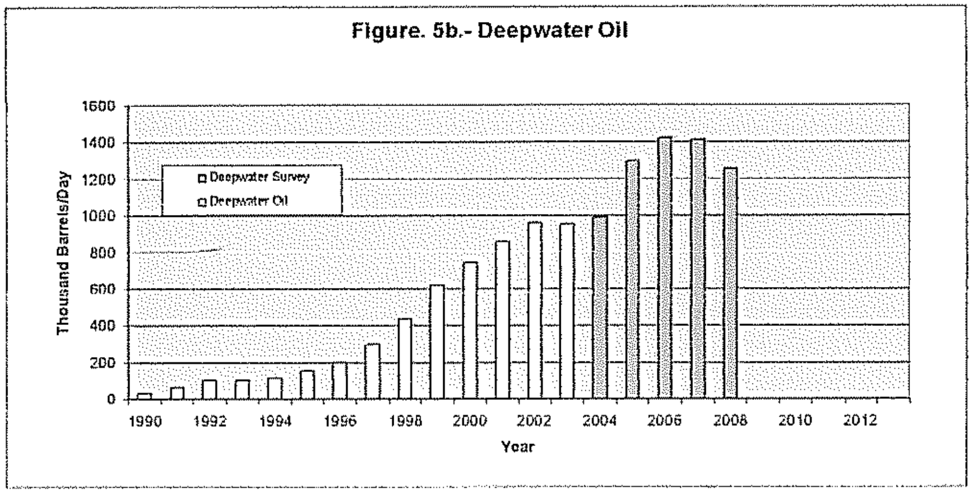


Figure 4. – Accuracy of previous forecasts.





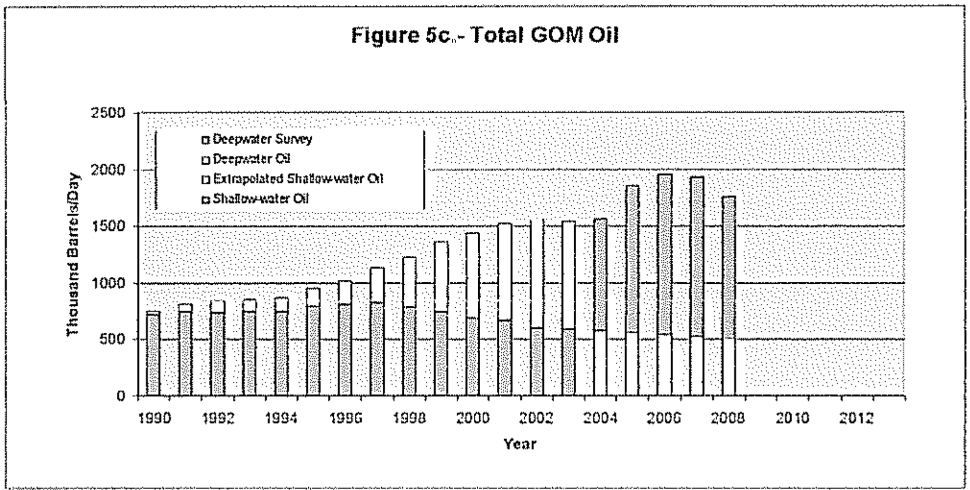


Figure 5. – Oil production estimates.

Figure 6a.- Shallow-water Gas

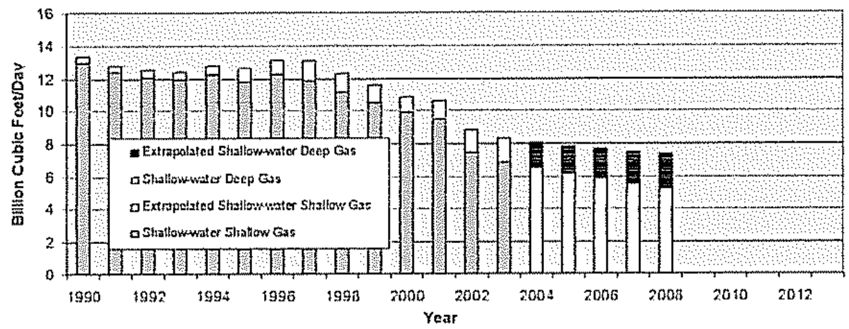


Figure 6b.- Deepwater Gas

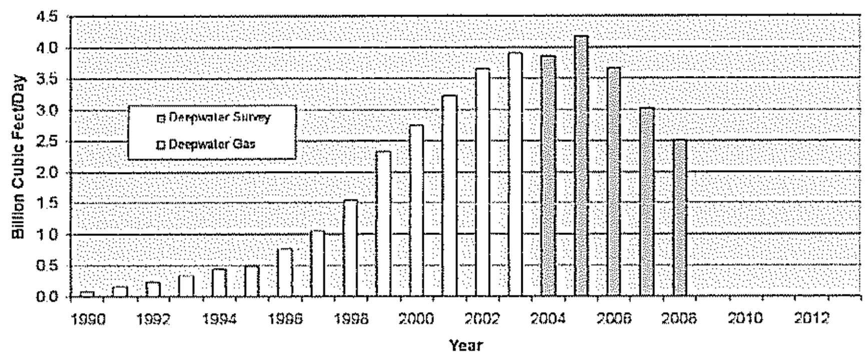


Figure 6c.- Total GOM Gas

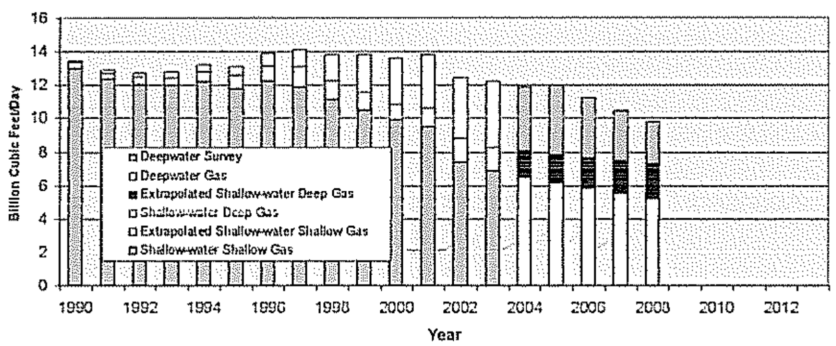


Figure 6. – Gas production estimates.

Section III - Extended Forecast

Gulf of Mexico operators have recently announced numerous deepwater discoveries that were not reported in the operator survey, possibly because these projects have not been fully assessed and operators have not yet committed to development schedules. Many of these industry-announced discoveries are likely to begin production within the next 10 years. Some may even begin production within the next 5 years.

The potential production from these industry-announced discoveries is added to the estimates from Section II and presented in Tables 2 and 3 and Figures 7a-c and 8a-c. This 10-year production forecast is more speculative than the 5-year forecast in Section II, and is based on the following assumptions:

1. The shallow-water production estimates (based on exponential declines for shallow-water oil and gas, excluding shallow-water deep gas, which is based on linear increase) from Section II are extended through 2013.
2. The deepwater production estimates from Section II (based on the operator survey) are assumed to decline exponentially at a rate of 12 percent each year (an assumption based on historic deepwater decline rates) from 2008 through 2013.
3. Ultimate recoverable volumes from the industry-announced discoveries are taken from independent, proprietary MMS assessments whenever available; otherwise, the industry-announced volumes are used.
4. During the first year of production, each project is assumed to produce at half its peak rate.
5. Projects with reserve volumes less than 200 million barrels of oil equivalent (MMBOE) are assumed to reach peak production in their second year and decline exponentially at 12 percent from that time forward.
6. Projects with reserve volumes over 200 MMBOE are assumed to reach peak production in their second year, sustain that peak rate for a total of four years, then decline exponentially at 12 percent from that time forward.
7. The estimated peak production rate for each project is based on the estimated recoverable reserves as follows:

Peak Rate = (0.00027455)*(ult rec rsvs) + 9000

where the peak rate is in barrels of oil equivalent (BOE) per day and the ultimate recoverable reserves (ult rec rsvs) are in BOE. This relationship was derived by plotting maximum production rates of known fields against the ultimate recoverable reserves of those fields and performing a linear regression. Note that MMS reserve estimates are on a field basis, so we assume here that this relationship based on historical field trends can be applied on a project basis.

8. Projects announced as gas discoveries are assumed to be 100-percent gas. The reserves of all other projects are assumed to be 61-percent oil and 39-percent gas, on the basis of an average of historic deepwater production.
9. The year when each industry-announced discovery is expected to begin production is roughly estimated by using available information.
10. All industry-announced discoveries with reserve estimates greater than 20 MMBOE are assumed to begin production within the next 10 years.

Table 2. – Gulf of Mexico Oil Rates (Thousand Barrels/Day)

Year	Shallow-water Oil	Extrapolated Shallow-water Oil	Deepwater Oil	Deepwater Survey	Extrapolated Deepwater Survey	Industry Announced Discoveries	Undiscovered Resources	Total GOM Oil
1990	720		33					753
1991	746		63					809
1992	734		102					836
1993	746		101					847
1994	748		115					862
1995	795		151					947
1996	814		198					1012
1997	831		297					1129
1998	782		436					1218
1999	740		617					1357
2000	691		743					1434
2001	664		855					1518
2002	600		956					1556
2003	586*		951*					1537*
2004		569		990		3		1562
2005		552		1297		18		1868
2006		536		1421		42	8	2006
2007		520		1409		96	26	2050
2008		504		1251		286	56	2098
2009		489			1110	496	97	2192
2010		475			984	615	145	2219
2011		461			873	714	199	2248
2012		447			774	743	256	2221
2013		434			687	697	313	2132

*Estimate

Table 3. - Gulf of Mexico Gas Rates (Billion Cubic Feet/Day)

Year	Shallow-water Shallow Gas	Extrapolated Shallow-water Shallow Gas	Shallow-water Deep Gas	Extrapolated Shallow-water Deep Gas	Deepwater Gas	Deepwater Survey	Extrapolated Deepwater Survey	Industry Announced Discoveries	Undiscovered Resources	Total GOM Gas
1990	12.97		0.39		0.08					13.45
1991	12.38		0.35		0.16					12.90
1992	12.03		0.48		0.24					12.74
1993	11.94		0.49		0.33					12.76
1994	12.20		0.58		0.44					13.22
1995	11.80		0.80		0.50					13.09
1996	12.24		0.91		0.76					13.91
1997	11.88		1.17		1.05					14.10
1998	11.14		1.14		1.54					13.81
1999	10.51		1.03		2.32					13.86
2000	9.91		0.94		2.74					13.58
2001	9.48		1.13		3.22					13.83
2002	7.41		1.38*		3.65					12.44*
2003	6.84*		1.45*		3.90*					12.19*
2004		6.48		1.56		3.85		0.01		11.90
2005		6.13		1.68		4.16		0.07		12.04
2006		5.80		1.81		3.65		0.15	0.06	11.48
2007		5.50		1.94		3.01		0.46	0.20	11.11
2008		5.20		2.09		2.50		1.47	0.41	11.67
2009		4.93		2.25			2.21	2.43	0.69	12.51
2010		4.66		2.42			1.96	2.78	1.03	12.85
2011		4.42		2.60			1.74	3.07	1.40	13.24
2012		4.18		2.80			1.54	3.12	1.82	13.46
2013		3.96		3.01			1.37	2.90	2.24	13.49

* Estimate

Figure 7a.- Shallow-water Oil

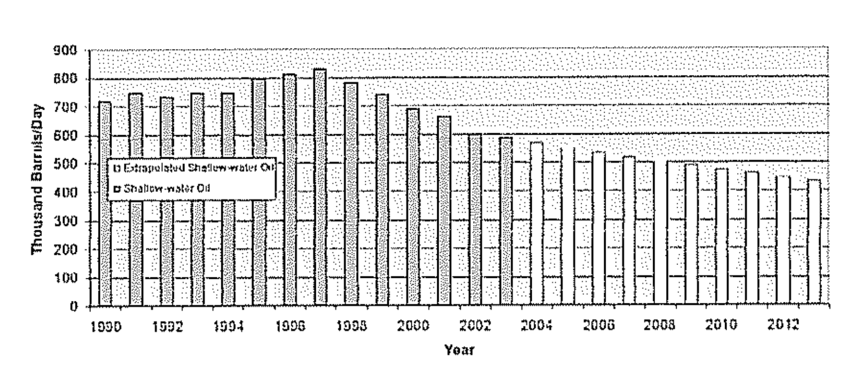


Figure 7b.- Deepwater Oil

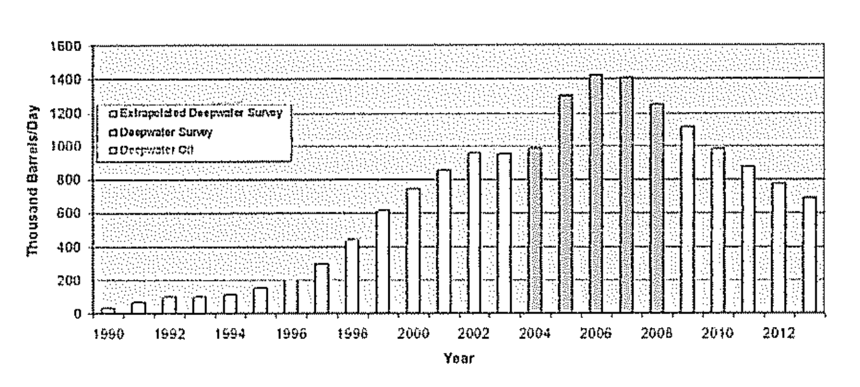


Figure 7c.- Total GOM Oil

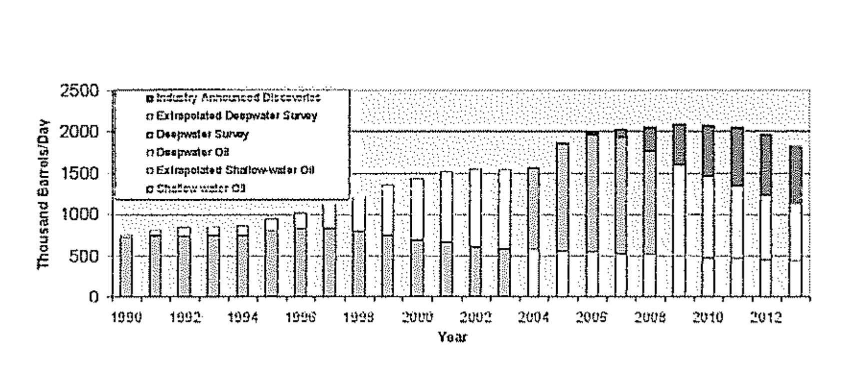


Figure 7 – Potential GOM oil production

Figure 8a.- Shallow-water Gas

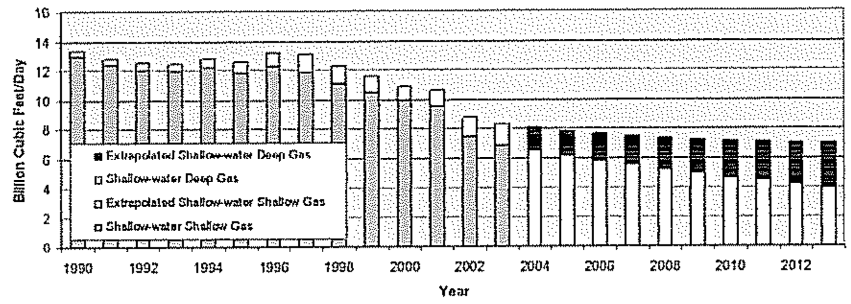


Figure 8b.- Deepwater Gas

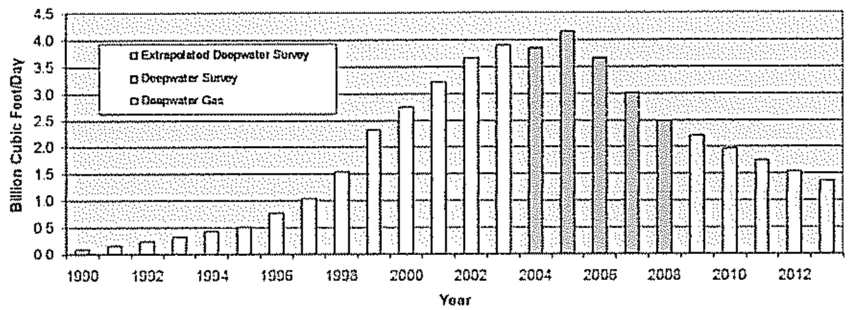


Figure 8c.-Total GOM Gas

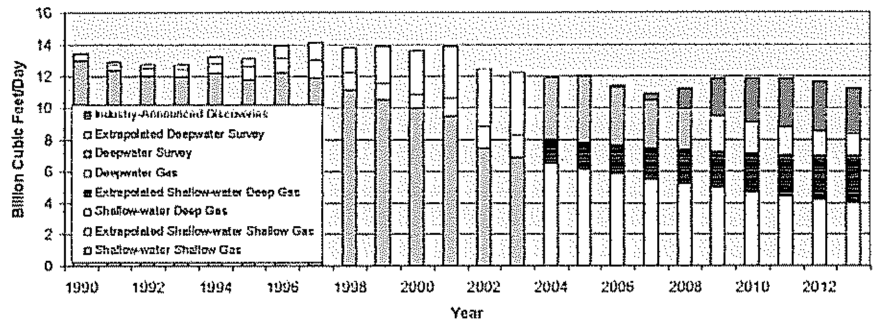


Figure 8. – Potential GOM gas production.

Section IV – Yet to Find

The shallow-water production forecasts in Sections II and III are based on extrapolations of historical production trends and several assumptions. This methodology inherently assumes that new reserves will be discovered and come on production just as they have in the past. The deepwater forecasts in Sections II and III include production from known discoveries. However, deepwater projects that have not yet been discovered are also likely to contribute to the total GOM oil and gas production during the forecast period, 2004 through 2013.

Figures 9 and 10 show our production forecast including the potential from deepwater projects that are yet to be discovered. In generating this forecast, we assume that the finding rate for new discoveries will not significantly deviate from historic levels during the forecast period. That is, these new discoveries will be realized as the result of continued investment anticipated in the exploratory drilling programs of many deepwater GOM operators, the level and intensity of investment in oil and gas product transportation infrastructure, and the number of high quality opportunities that remain untested throughout the deepwater Gulf.

The "yet-to-find" deepwater GOM discoveries anticipated during the next nine years are expected to occur on both currently leased OCS tracts as well as on OCS tracts that are expected to be leased at future GOM lease sales. We assume that the average volume of "yet-to-find" recoverable resources will be within the range of historically observed average volumes discovered on the population of deepwater tracts leased in GOM sales held between 1980 and 1995. Further, we assume that the production profiles that result from the sale-specific "yet-to-find" new discoveries will be similar to typical historical production profiles.

The estimated production schedules and daily production volumes contributing to the "yet-to-find" component of this forecast were developed using data from MMS' corporate database and the methodology outlined below

1) Oil and gas reservoir volumes are summed for each lease sale.
2) Distributions of oil and gas volumes, discovered from the population of deepwater tracts leased in an individual sale, are developed for the GOM Central and Western Planning Areas.
3) Oil and gas production profiles are developed for the population of deepwater tracts issued in each individual lease sale.
4) The production profiles are analyzed using historic sale-specific production data, and a "typical sale" production profile is developed for each planning area.
5) The range of total oil and gas volumes estimated to be discovered on leases issued in a typical sale is applied to its respective production profile (Central or Western, oil or gas), and a forecast of annual production expected to result from a single sale is generated.
6) For lease sale years where a portion of the total deepwater production anticipated to result from the sale has been realized, the yet-to-find volumes are allocated on the basis of the "typical sale" production profile and the number of years that remain on the primary terms of the population of tracts leased in a given lease sale year
7) Since one Central and one Western GOM sale are typically held in a given year, an estimate of the production expected from all future lease sales is generated by summing the annual production of a series of single sale production profiles that are each offset by one year.

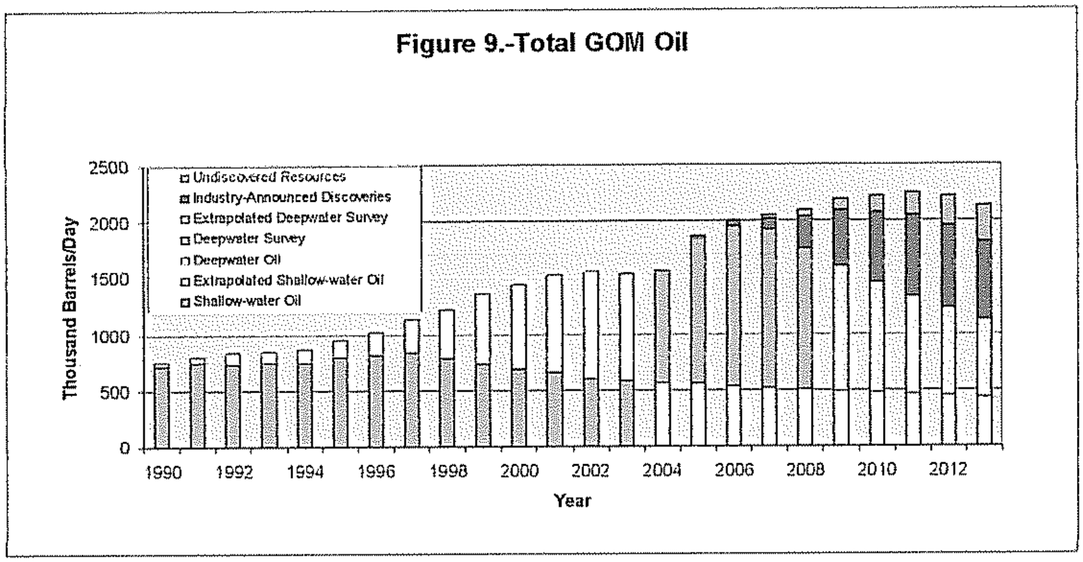


Figure 9. – Potential GOM oil production including undiscovered resources.

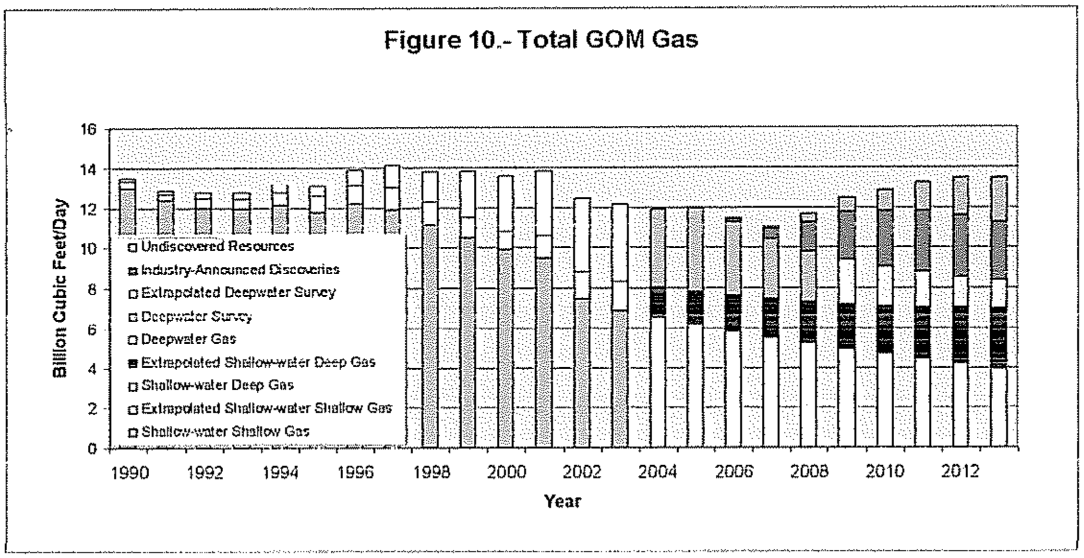


Figure 10. – Potential GOM gas production including undiscovered resources.

Conclusions

Historic oil production in the Gulf of Mexico (GOM) increased steadily from 1990 through 2001 and leveled off in 2002 and 2003 Shallow-water oil production declined steadily since 1997, but was offset by increasing deepwater production during that period. Historic gas production in the GOM followed similar trends. While shallow-water deep-gas production increased during the period 1990 through 2003, the remaining portion of the shallow-water gas production dropped steadily from 1996 though 2003. Increasing deepwater production was not sufficient to prevent an overall decline in total GOM production through 2003.

The deepwater operator survey, which has been reliable in previous editions of this report, indicates that the deepwater oil production will increase significantly over the next few years and the total GOM oil production will reach about 2 million barrels of oil per day (MMBOPD). Section II of this report, however, indicates that deepwater and shallow-water deep-gas production will not contribute enough volume to offset a short-term decline in total GOM gas production.

Section III of this report shows the estimated additional production that could come from deepwater projects not yet sanctioned. The extended forecast in Section III indicates that the existing discovered reserves are capable of sustaining total GOM oil production levels near 2 MMBOPD and gas production levels near 12 billion cubic ft per day (BCFPD). Realization of this potential will depend on operator commitments to develop these reserves within the next 10 years. The possible additional production from deepwater projects that are not yet discovered could increase production levels further, as shown in Section IV

Each section of this report adds potential GOM production to the forecast and the uncertainty increases with each subsequent section. The data from each section of this report are presented separately in Tables 2 and 3 so that the reader may decide the degree of certainty that he or she deems appropriate. Whatever degree of certainty used, one can conclude that GOM oil production rates should increase beyond current levels in the next few years. Total GOM gas production rates, however, would require significant contributions from as yet undiscovered deepwater projects to rise above current levels.

Contributors

The Minerals Management Service acknowledges and thanks the following deepwater operators for their cooperation in this report:

Amerada Hess Corporation
Anadarko Petroleum Corporation
BHP Billiton Petroleum (Americas) Inc.
BP America Production Company
Conoco Philips
ChevronTexaco Inc.
Dominion Exploration & Producing
ENI Petroleum Co.
El Paso Production
ExxonMobil Corporation
Kerr-McGee Corporation
Mariner Energy, Inc.
Murphy Exploration & Production Company
Noble Energy Inc
Pioneer Natural Resources USA, Inc.
Shell Offshore Inc
TotalFinaElf E&P USA, Inc.
Walter Oil & Gas

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Notice

Our goal is to publish a reliable production forecast based on the data available Therefore, we periodically review our methodology in order to improve our process and provide accurate information. Please contact the Regional Supervisor, Production and Development, Gulf of Mexico OCS Region, Minerals Management Service, 1201 Elmwood Park Boulevard, New Orleans, Louisiana, 70123, to communicate any questions you have or ideas for consideration in our next report. The telephone number is (504) 736-2675

The Department of the Interior Mission

As the Nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally owned public lands and natural resources. This includes fostering sound use of our land and water resources; protecting our fish, wildlife, and biological diversity; preserving the environmental and cultural values of our national parks and historical places; and providing for the enjoyment of life through outdoor recreation. The Department assesses our energy and mineral resources and works to ensure that their development is in the best interests of all our people by encouraging stewardship and citizen participation in their care. The Department also has a major responsibility for American Indian reservation communities and for people who live in island territories under U.S. administration.

The Minerals Management Service Mission

As a bureau of the Department of the Interior, the Minerals Management Service's (MMS) primary responsibilities are to manage the mineral resources located on the Nation's Outer Continental Shelf (OCS), collect revenue from the Federal OCS and onshore Federal and Indian lands, and distribute those revenues.

Moreover, in working to meet its responsibilities, the **Offshore Minerals Management Program** administers the OCS competitive leasing program and oversees the safe and environmentally sound exploration and production of our Nation's offshore natural gas, oil and other mineral resources. The MMS **Minerals Revenue Management** meets its responsibilities by ensuring the efficient, timely and accurate collection and disbursement of revenue from mineral leasing and production due to Indian tribes and allottees, States and the U.S. Treasury

The MMS strives to fulfill its responsibilities through the general guiding principles of: (1) being responsive to the public's concerns and interests by maintaining a dialogue with all potentially affected parties and (2) carrying out its programs with an emphasis on working to enhance the quality of life for all Americans by lending MMS assistance and expertise to economic development and environmental protection

MMS Securing Ocean Energy & Economic Value for America

Exhibit No. SR-10
Docket No. RP07-___-000

Energy Information Administration (EIA)
Annual Energy Outlook 2007

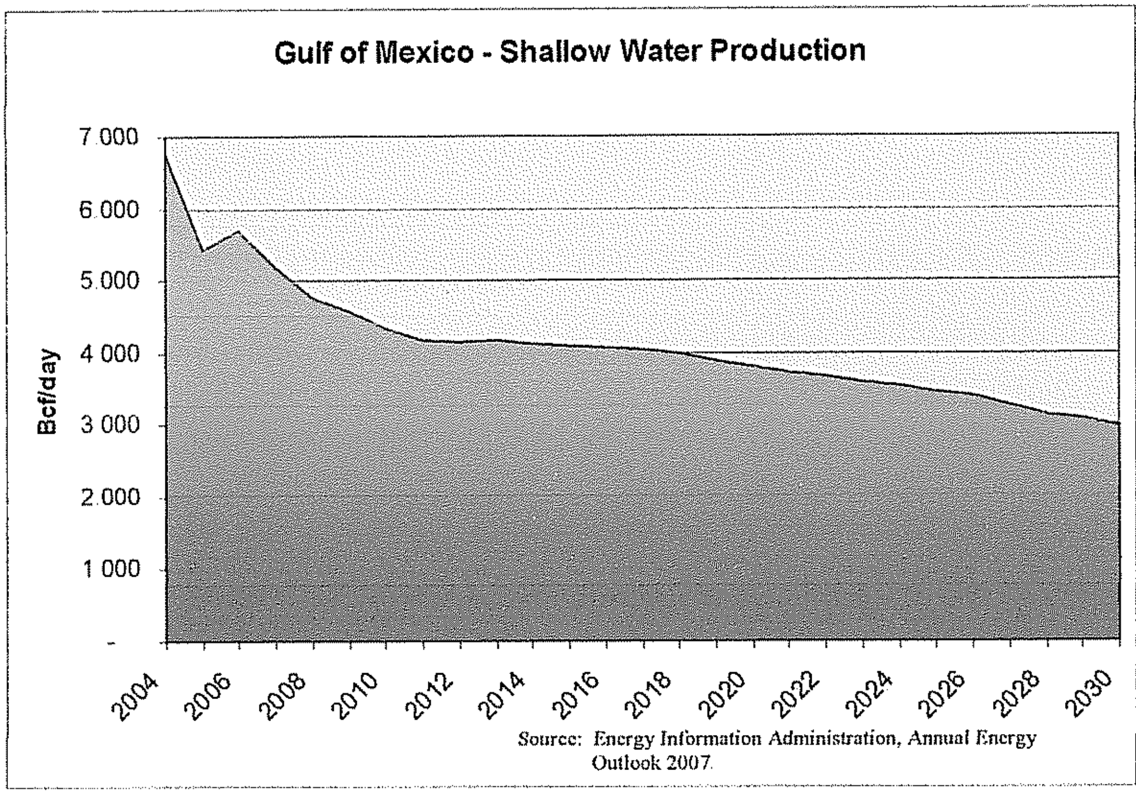


Exhibit No. SR-11
Docket No. RP07-___-000

NEWFIELD

Newfield Exploration Company Sells Shallow Water Gulf of Mexico Portfolio

HOUSTON, June 21, 2007 /PRNewswire-FirstCall via COMTEX News Network/ -- Newfield Exploration Company (NYSE: NFX) today announced the signing of a purchase and sale agreement to sell all of its producing properties in the shallow water Gulf of Mexico to McMoRan Exploration Co. (NYSE: MMR) for a total cash consideration of $1.1 billion and the assumption of liabilities associated with future abandonment of wells and platforms. The sale is expected to close in July 2007, subject to customary closing conditions.

"Today's announcement is a significant step in our on-going plan to create a longer-lived reserve base with sustainable and predictable production growth," said David A. Trice, Newfield Chairman, President and CEO. "The sale of our shelf properties is the first in a series of planned divestitures that also include our assets in Bohai Bay China, the North Sea and select properties in Texas and Oklahoma. Pro-forma for these transactions, our reserve life should increase to approximately 11 years and we will have visible production growth from the development of our in-hand assets. Newfield has a long history in the Gulf of Mexico and we will continue to focus on growing our deepwater portfolio where we have an interest in three producing fields and two field developments underway that will create future production growth.

"McMoRan has acquired some very good properties in this transaction," said Trice. "But the most valuable assets will be the people who will join McMoRan's team. Their efforts are responsible for Newfield's success in the Gulf of Mexico. We will be retaining our shelf exploration team and we will continue to explore and drill shelf prospects."

Current net production from the properties to be sold is approximately 270 MMcfe/d. Newfield's net production from its shelf properties in the first six months of 2007 is expected to be approximately 46 Bcfe. The effective date of this transaction is July 1, 2007.

This transaction also provides McMoRan with an undivided interest in Newfield's ultra-deep acreage in its Treasure Island and Treasure Bay exploration program. Newfield will retain a working interest ranging from 10-25% in the Treasure Island and Treasure Bay acreage, which encompasses 85 lease blocks. Upon closing, McMoRan will assume operatorship of the Treasure Island leasehold, subject to customary approvals. In addition, McMoRan will join Newfield in a 50-50 joint venture on Newfield's primary term shelf acreage. This venture will cover 19 lease blocks, or nearly 100,000 gross acres.

Newfield expects to utilize Internal Revenue Code Section 1031 Tax Deferred Exchange rules for the sale of its Gulf of Mexico shelf assets and the recent $575 million acquisition of Rocky Mountain assets from Stone Energy. As a result, after-tax proceeds from the sale of the Gulf of Mexico assets are expected to be more than $1 billion. Utilization of Sec 1031 rules creates nearly $30 million of additional value in these transactions.

Newfield will use the proceeds from the sale of the Gulf of Mexico assets to finance the Rocky Mountain acquisition, pay down existing debt and fund the remainder of its 2007 capital expenditures.

Jefferies Randall & Dewey and Morgan Stanley & Co. Incorporated acted as financial advisors to Newfield in connection with its Gulf of Mexico asset sale.

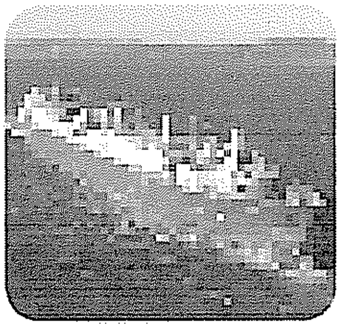
Newfield Exploration Company is an independent crude oil and natural gas exploration and production company. The Company relies on a proven growth strategy of growing reserves through the drilling of a balanced risk/reward portfolio and select acquisitions. Newfield's domestic areas of operation include the onshore Gulf Coast, the Anadarko and Arkoma Basins of the Mid-Continent, the Uinta Basin of the Rocky Mountains and the Gulf of Mexico. The Company has international operations in Malaysia, the U.K. North Sea and China.

**The statements set forth in this release regarding the anticipated closing and the closing date for the acquisition and proposed divestitures are forward looking and are based upon assumptions and anticipated results that are subject to numerous uncertainties, including the satisfaction of closing conditions. Failure to satisfy these conditions or delay in satisfying these conditions could result in the termination of the transaction or delay the closing of the transaction. Completion of Newfield's other proposed divestitures is subject to Newfield receiving offers that it considers acceptable for the properties.

For information, contact:
Investor Relations: Steve Campbell (281) 847-6081
Media Relations: Keith Schmidt (281) 674-2650
Email: info@newfield com

Exhibit No. SR-12
Docket No. RP07-___-000

Gulf Gateway Energy Bridge™ Deepwater Port


EBRV Excelsior

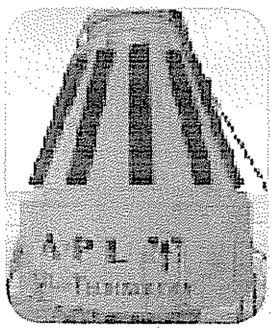
Gulf Gateway Deepwater Port Overview

The Gulf Gateway Energy Bridge™ deepwater port (Gulf Gateway) is owned by Excelerate Energy Limited Partnership. Located in Block 603 of the West Cameron Area, South Addition at a distance of approximately 116 miles from the Louisiana coast, Gulf Gateway has a baseload capacity of 500 million cubic feet per day with a peak capacity of 690 million cubic feet per day. Each Energy Bridge™ Regasification Vessel (EBRV) that arrives at Gulf Gateway utilizes its onboard tanks to act as LNG storage for roughly three billion cubic feet equivalent of vaporous natural gas.

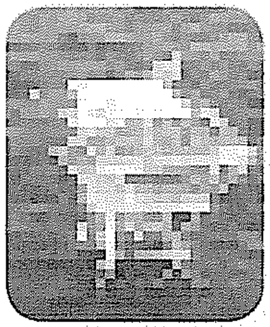
Key Components

Gulf Gateway is comprised of the following components:

- A Submerged Turret Loading™ buoy (STL Buoy) and related anchors, anchor lines, a flexible riser, and a subsea manifold,
- A gas metering platform for measurement of volume and composition of gas flowing to downstream pipelines;
- A 1.89 mile, 20-inch diameter offloading pipeline from the subsea manifold to the metering platform;
- A 1.37 mile, 18-inch diameter pipeline from the metering platform to the Blue Water Pipeline; and,
- A 3.92 mile, 20-inch diameter pipeline from the metering platform to the Sea Robin Pipeline.


STL Buoy

Once an EBRV reaches Gulf Gateway, it retrieves and connects to the STL Buoy commence regasification of the LNG on-board. Natural gas is then discharged through the STL Buoy, into the flexible riser and delivered through the offloading pipeline to the metering platform. On the metering platform, the natural gas flows through one of two gas measurement meters – one measuring gas destined for the Sea Robin Pipeline system and a second measuring gas to be delivered to the Blue Water Pipeline system.


Metering Platform

After metering, the gas pressure is reduced by regulators on the platform so that the gas can enter either the Sea Robin Pipeline or Blue Water Pipeline system at the pressure prescribed by the operator's tariff for each of those systems.

The natural gas transported by the Sea Robin Pipeline and the Blue Water Pipeline comes ashore on the Louisiana coast near the Henry Hub (trading point for NYMEX natural gas contracts), providing substantial access to downstream markets and gas processing infrastructure. With the gas processing infrastructure in place downstream and substantial pipeline capacity available, Gulf Gateway is able to receive natural gas from virtually any source in the world and effectively deliver it to onshore markets.

Offshore construction of Gulf Gateway commenced in August 2004 and was completed in February 2005 at a cost of approximately US$70 million. First cargo delivery occurred with the docking of the world's first EBRV Excelsior on March 17, 2005.

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Exhibit No. SR-13
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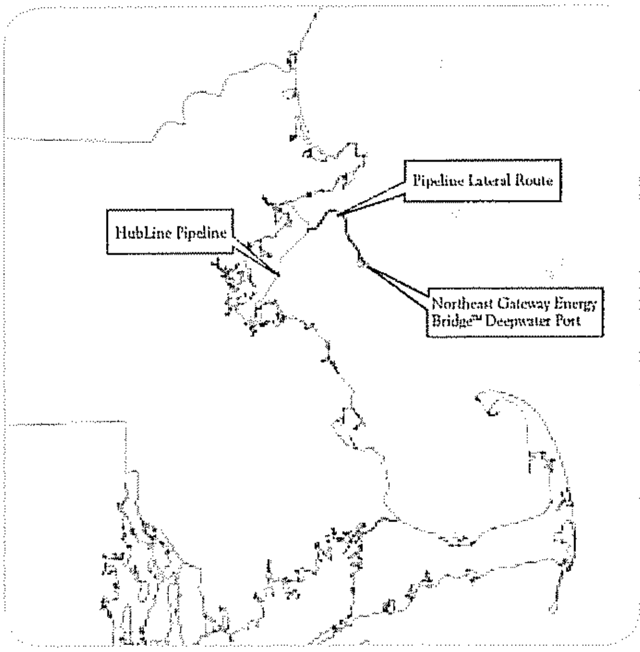
Northeast Gateway

Northeast Gateway Energy Bridge™ Deepwater Port

Northeast Gateway Deepwater Port Overview
The Northeast Gateway Energy Bridge™ deepwater port (Northeast Gateway) will be located offshore in Massachusetts Bay, approximately 13 miles southeast of the city of Gloucester, Massachusetts in federal waters 250 to 270 feet in depth. Northeast Gateway will deliver regasified LNG to onshore markets via a new 24-inch pipeline lateral approximately 16.5 miles in length to be constructed, owned, and operated by



Algonquin Gas Transmission, LLC (Algonquin). This pipeline lateral will connect to the existing HubLine Pipeline System that traverses Massachusetts Bay and integrates with the New England natural gas grid, allowing Northeast Gateway to deliver an average of 400 million cubic feet per day (MMcf/d) of natural gas with a peak sendout of 800 MMcfd.

Northeast Gateway will consist of two subsea Submerged Turret Loading™ buoys (STL Buoys), two flexible risers, two subsea manifolds, and two subsea flowlines to connect to Algonquin's pipeline lateral. Each STL Buoy will connect to its own subsea manifold using the flexible riser assembly. The subsea manifold will then be tied into the subsea flowline, subsequently connecting to Algonquin pipeline lateral.

Northeast Gateway is designed to provide a reliable supply of clean burning natural gas into the natural gas distribution system for Massachusetts and New England while minimizing environmental impacts, mitigating safety concerns and increasing energy diversity for the onshore industries and communities that it serves.

Project Schedule
Construction of Northeast Gateway will be done in conjunction with the installation of Algonquin's pipeline lateral, and is scheduled to commence late summer 2006. Given the short duration of construction required for Energy Bridge™ completion is targeted for the spring of 2007.

Regulatory Process
Governed under the Deepwater Port Act (DWPA), Northeast Gateway's application for a deepwater port license is filed with the U.S. Coast Guard and the Maritime Administration. Under the DWPA, the Governor of Massachusetts (the adjacent coastal state) has approval authority over the Northeast Gateway project. To facilitate this approval, an Environmental Notification Form was filed with the Executive Office of Environmental Affairs (EOEA) in the State of Massachusetts to establish a coordinated environmental review process that will satisfy the requirements of the Massachusetts Environmental Policy Act (MEPA) and the National Environmental Policy Act (NEPA).

By combining the MEPA and NEPA processes, Northeast Gateway will establish channels of communication between all reviewing agencies that will facilitate a more efficient, thorough, and logical review process for all parties involved, including the public at large. In addition, it is intended that the MEPA process provide the means by which the Governor of Massachusetts can act affirmatively on the approval of the Northeast Gateway application.

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