MARINER ENERGY INC
Form S-1/A
February 09, 2006

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As filed with the Securities and Exchange Commission on February 9, 2006

Registration No. 333-124858

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Amendment No. 4
to
Form S-1
REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

Mariner Energy, Inc.
(Exact name of registrant as specified in its charter)

Delaware	1311	86-0460233
(State or other jurisdiction of incorporation or organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification Number)*

One Briar Lake Plaza, Suite 2000
2000 West Sam Houston Parkway South
Houston, Texas 77042
(713) 954-5500
(Address, including zip code, and telephone number, including area code, of registrant s principal executive offices)

Teresa Bushman
Vice President and General Counsel
Mariner Energy, Inc.
One Briar Lake Plaza, Suite 2000
2000 West Sam Houston Parkway South
Houston, Texas 77042
(713) 954-5505
(Name, address, including zip code, and telephone number, including area code, of agent for service)

Copies to:

Kelly B. Rose Baker Botts L.L.P. One Shell Plaza 910 Louisiana Houston, Texas 77002 (713) 229-1796	Brian J. Lynch, Esq. Robert A. Welp, Esq. Hogan & Hartson L.L.P. 8300 Greensboro Drive, Suite 1100 McLean, Virginia 22102 (703) 610-6100

Approximate date of commencement of proposed sale to the public: From time to time after the effective date of this registration statement.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act, check the following box. þ

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, please check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If delivery of the prospectus is expected to be made pursuant to Rule 434, please check the following box. o

The registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act or until the registration statement shall become effective on such date as the Commission, acting pursuant to said Section 8(a), may determine.

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The information in this prospectus is not complete and may be changed. These securities may not be sold until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities and it is not soliciting an offer to buy these securities in any state where the offer or sale is not permitted.

Subject to Completion dated February 9, 2006

PROSPECTUS

33,348,130 Shares
Common Stock

This prospectus relates to up to 33,348,130 shares of the common stock of Mariner Energy, Inc., which may be offered for sale by the selling stockholders named in this prospectus. The selling stockholders acquired the shares of common stock offered by this prospectus in private equity placements. We are registering the offer and sale of the shares of common stock to satisfy registration rights we have granted.

We are not selling any shares of common stock under this prospectus and will not receive any proceeds from the sale of common stock by the selling stockholders. The shares of common stock to which this prospectus relates may be offered and sold from time to time directly from the selling stockholders or alternatively through underwriters or broker-dealers or agents. The shares of common stock may be sold in one or more transactions, at fixed prices, at prevailing market prices at the time of sale or at negotiated prices. Please read Plan of Distribution.

Prior to this offering, there has been no public market for our common stock. Our common stock has been approved for listing on the New York Stock Exchange, subject to the completion of our proposed merger with Forest Energy Resources, Inc.

Investing in our common stock involves risks. You should read the section entitled Risk Factors beginning on page 24 for a discussion of certain risk factors that you should consider before investing in our common stock.

You should rely only on the information contained in this prospectus or any prospectus supplement or amendment. We have not authorized anyone to provide you with different information. We are not making an offer of these securities in any state where the offer is not permitted.

Neither the Securities and Exchange Commission (the SEC) nor any state securities commission has approved or disapproved of these securities or determined whether this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The date of this prospectus is , 2006.

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WHERE YOU CAN FIND INFORMATION

We have filed with the SEC, under the Securities Act of 1933, as amended (the Securities Act), a registration statement on Form S-1 with respect to the common stock offered by this prospectus. This prospectus, which constitutes part of the registration statement, does not contain all the information set forth in the registration statement or the exhibits and schedules which are part of the registration statement, portions of which are omitted as permitted by the rules and regulations of the SEC. Statements made in this prospectus regarding the contents of any contract or other documents are summaries of the material terms of the contract or document. With respect to each contract or document filed as an exhibit to the registration statement, reference is made to the corresponding exhibit. For further information pertaining to us and to the common stock offered by this prospectus, reference is made to the registration statement, including the exhibits and schedules thereto, copies of which may be inspected without charge at the public reference facilities of the SEC at 100 F Street, N.E., Washington, D.C. 20549. Copies of all or any portion of the registration statement may be obtained from the SEC at prescribed rates. Information on the public reference facilities may be obtained by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains a web site that contains reports, proxy and information statements and other information that is filed electronically with the SEC. The web site can be accessed at *www.sec.gov.*

Upon completion of this offering, we will be required to comply with the informational requirements of the Securities Exchange Act of 1934, as amended (the Exchange Act), and, accordingly, will file current reports on Form 8-K, quarterly reports on Form 10-Q, annual reports on Form 10-K, proxy statements and other information with the SEC. Those reports, proxy statements and other information will be available for inspection and copying at the public reference facilities and internet site of the SEC referred to above.

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SUMMARY

This summary highlights selected information from this prospectus, but does not contain all information that you should consider before investing in the shares. You should read this entire prospectus carefully, including the Risk Factors beginning on page 24 of this prospectus and the financial statements included elsewhere in this prospectus. References to Mariner, the Company, we, us, and our refer to Mariner Energy, Inc. The estimates of our proved reserves as of December 31, 2002, 2003 and 2004 included in this prospectus are based on reserve reports prepared by Ryder Scott Company, L.P., independent petroleum engineers (Ryder Scott). A summary of their report on our proved reserves as of December 31, 2004 is attached to this prospectus as Annex A. We have provided definitions for some of the industry terms used in this prospectus in the Glossary of Oil and Natural Gas Terms beginning on page 191 of this prospectus.

In this prospectus:

The terms we , us , our and like terms, and the term Mariner, refer to Mariner Energy, Inc.;

MEI Sub refers to MEI Sub, Inc.;

Forest refers to Forest Oil Corporation;

Forest Energy Resources refers to Forest Energy Resources, Inc.; and

Forest Gulf of Mexico operations refers to the offshore Gulf of Mexico operations conducted by Forest that have been contributed to Forest Energy Resources and the shares of which will be spun-off to Forest shareholders.

About Mariner Energy, Inc.

Mariner Energy, Inc. is an independent oil and gas exploration, development and production company with principal operations in the Gulf of Mexico, both shelf and deepwater, and the Permian Basin in West Texas. As of December 31, 2004, we had 237.5 Bcfe of estimated proved reserves, of which approximately 64% were natural gas and 36% were oil and condensate. As of December 31, 2004, the present value, discounted at 10% per annum, of estimated future net revenues from our estimated proved reserves, before income tax (PV10), was approximately $668 million, and our standardized measure of discounted future net cash flows attributable to its estimated proved reserves was approximately $494.4 million. Please see Business Estimated Proved Reserves for a reconciliation of PV10 to the standardized measure of discounted future net cash flows. As of December 31, 2004, approximately 46% of our estimated proved reserves were classified as proved developed. For the year ended December 31, 2004, our total net production was 37.6 Bcfe. Of our estimated proved reserves, 48% are located in the Permian Basin in West Texas, 37% in the Gulf of Mexico deepwater and 15% on the Gulf of Mexico shelf as of December 31, 2004. In the three-year period ended December 31, 2004, we deployed approximately $337 million of capital on acquisitions, exploration and development while adding approximately 191 Bcfe of estimated proved reserves and producing approximately 111 Bcfe.

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Significant Properties

We own oil and gas properties, producing and non-producing, onshore in Texas and offshore in the Gulf of Mexico, primarily in federal waters. Our largest properties, based on the present value of estimated future net proved reserves as of December 31, 2004, are shown in the following table.

	Operator	Mariner Working Interest	Approximate Water Depth (Feet)	Gross Producing Wells(1)	Date Production Commenced/ Expected	Estimated Proved Reserves (Bcfe)	PV10 Value(2)	Standardized Measure
		%					(in $ millions)	(in $ millions)
West Texas Permian Basin:								
Aldwell Unit	Mariner	66.5(3)	Onshore	185	1949	112.7	$ 203.8	
Gulf of Mexico Deepwater:								
Mississippi Canyon 296/252 (Rigel)	Dominion	22.5	5,200	0	Second Quarter 2006	22.4	82.9	
Viosca Knoll 917/961/962 (Swordfish)	Mariner(4)	15.0	4,700	2	Fourth Quarter 2005	13.4	59.3	
Green Canyon 516 (Yosemite)	ENI	44.0	3,900	1	2002	15.1	66.6	
Mississippi Canyon 718 (Pluto)(5)	Mariner	51.0	2,830	0	1999	9.0	31.7	
Green Canyon 178 (Baccarat)	W&T	40.0	1,400	0	Third Quarter 2005	4.0	14.3	
Green Canyon 472/473 (King Kong)	ENI	50.0	3,850	0	2002	1.2	2.0	
Gulf of Mexico Shelf:								
Mississippi Canyon 66 (Ochre)(6)	Mariner	75.0	1,150	0	2004	3.6	11.7	
Other Properties				43		56.1	195.7	
Total:				231		237.5	$ 668.0	$ 494.4

(1) Wells producing or capable of producing as of December 31, 2004.

(2) Please see Business Estimated Proved Reserves for a definition of PV10 and a reconciliation of PV10 to the standardized measure of discounted future net cash flows.

(3) We operate the field and own working interests in individual wells ranging from approximately 33% to 84%.

(4) Mariner served as operator until December 2005, at which time pursuant to certain contractual arrangements, Noble Energy, Inc., a 60% partner in the project, began serving as operator.

(5) This field was shut-in in April 2004 pending the drilling of a new well and installation of an extension to the existing infield flowline and umbilical. As a result, as of December 31, 2004, 9.0 Bcfe of our net proved reserves attributable to this project were classified as proved undeveloped reserves. We expect production from Pluto to recommence in the second quarter of 2006.

(6) Field has been shut in since September 2004 due to destruction of host platform by Hurricane Ivan.

The distribution of our proved reserves reflects our efforts over the last three years to diversify our asset base, which in prior years had been focused primarily in the Gulf of Mexico deepwater. We have shifted some of our focus on deepwater activities to increased exploration and development on the Gulf of Mexico shelf and exploitation of our West Texas Permian Basin properties. By allocating our resources among these three areas, we expect to balance the risks associated with the exploration and development of our asset base. We intend to continue to pursue moderate-risk exploratory and development drilling projects in the Gulf of Mexico deepwater and on the Gulf of Mexico shelf, including select deep shelf prospects, and also target low-risk infill drilling projects in West Texas. It is our practice to generate most of our prospects internally, but from time to time we also acquire third-party generated prospects. We then drill to find oil and natural gas reserves, a process that we refer to as growth through the drill bit.

West Texas Permian Basin

We operate and own working interests in individual wells ranging from 33% to 84% (with an average working interest of approximately 66.5%), in the 18,500-acre Aldwell Unit. The field is located in the heart of the Spraberry geologic trend southeast of Midland, Texas, and has produced oil and gas since 1949. We began our recent redevelopment of the Aldwell Unit by drilling eight wells in the fourth quarter of 2002, 43 wells in 2003, and 54 wells in 2004. As of December 31, 2004, there were a total of 185 wells producing or capable of producing in the field. Our aggregate net capital expenditures for the 2004 drilling program in the field were approximately $20.3 million, and we added 27 Bcfe of proved reserves, while producing 4.0 Bcfe.

During 2005, we have accelerated our development program in West Texas. Through September 30, 2005, we had drilled 65 new wells at our Aldwell and North Stiles Units. All of our drilling in the Aldwell and North Stiles Units has resulted in commercially successful wells that are expected to produce in quantities sufficient to exceed costs of drilling and completion. Our net production from onshore wells for the nine months ended September 30, 2005 averaged approximately 17 MMcfe per day. We have completed construction of our own oil and gas gathering system and compression facilities in the Aldwell Unit. We began flowing gas production through the new facilities on June 1, 2005. We have also entered into new contracts with third parties to provide processing of our natural gas and transportation of our oil produced in the unit. The new gas arrangement also provides us with the option to sell our gas to one of four firm or five interruptible sales pipelines versus a single outlet under the former arrangement. We expect these arrangements to improve the economics of production from the Aldwell Unit.

In August 2005, but effective in October 2005, we entered into an agreement covering approximately 33,000 acres in West Texas, pursuant to which, upon closing, we acquired an approximate 35% working interest in approximately 200 existing producing wells effective November 1, 2005, and committed to drill an additional 150 wells within a four year period, funding $36.5 million of our partner s share of drilling costs for such 150-well drilling program. We will obtain an assignment of an approximate 35% working interest in the entire committed acreage upon completion of the 150-well program.

Gulf of Mexico Deepwater

As of September 30, 2005 we held interests in 11 fields in the Gulf of Mexico deepwater, four of which we operate. The Gulf of Mexico deepwater accounts for 37%, or 86.7 Bcfe, of our December 31, 2004 proved reserves. Our net production from deepwater wells for the nine months ended September 30, 2005 averaged approximately 33 MMcfe per day (see Recent Developments below for a discussion of the effects of hurricanes Katrina and Rita). As of September 30, 2005, we held interests in 55 Gulf of Mexico blocks with water depths of over 1,300 feet and had approximately 132,000 net undeveloped acres under lease. In 2004, we spent approximately $63.5 million net on drilling and completion activities in the deepwater. We drilled five exploratory wells, four of which were successful, and one development well, which was also successful.

In 2004, four subsea tiebacks were in the development phase in the deepwater: Mississippi Canyon 718 (Pluto), Viosca Knoll 917 (Swordfish), Green Canyon 178 (Baccarat) and Mississippi Canyon 296 (Rigel). These four subsea tieback projects contain approximately 49 Bcfe of proved reserves as of December 31, 2004. Swordfish, Baccarat and Rigel are the results of Mariner-generated prospects. The Swordfish and Pluto projects are operated by Mariner, and the Baccarat and Rigel projects are operated by other working interest owners. Currently approximately 7 MMcfe per day of production remains shut-in awaiting repairs due to Hurricanes Katrina and Rita, primarily associated with the Baccarat property. While we believe physical damage to our existing platforms and facilities was relatively minor from both hurricanes, the effects of the storms caused damage to onshore pipeline and processing

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facilities that resulted in a portion of our production being temporarily shut-in, or in the case of our Swordfish project, postponed. In addition, Hurricane Katrina caused damage to platforms that host three of our development projects: Pluto, Rigel, and Mississippi Canyon 66 (Ochre). Repairs to these facilities may take up to six months, pushing commencement of production on these projects into 2006.

Gulf of Mexico Shelf

In the past two years, we have increased our drilling activities on the Gulf of Mexico shelf. As of September 30, 2005, we held interests in 21 fields on the Gulf of Mexico shelf, eight of which we operate. Gulf of Mexico shelf properties comprise 15%, or 36 Bcfe, of our proved reserves as of December 31, 2004. Our net production from these wells for the nine months ended September 30, 2005 averaged approximately 32 MMcfe per day (see Recent Developments below for a discussion of the effects of hurricanes Katrina and Rita). As of September 30, 2005, we held interests in 59 Gulf of Mexico shelf blocks and had approximately 81,000 net undeveloped acres under lease. During 2004, we spent approximately $38.3 million to drill nine exploratory wells, three of which were successful, and two development wells, one of which was successful, on the Gulf of Mexico shelf.

First production from our Ewing Bank 977 (Dice) project, a subsea tieback, and High Island 46 (Green Pepper) commenced in January 2005. First production from our two West Cameron 333 wells (Royal Flush) commenced during February 2005.

Recent Developments

Approximately 29 Mmcfe per day of natural gas and approximately 3,000 bbls per day of oil and condensate net to our interest were initially shut-in as a result of the effects of Hurricane Katrina in August 2005. The majority of this production was returned within two weeks of the hurricane, and substantially all within three weeks of the hurricane. Additionally, we are experiencing delays in startup of three of our projects primarily as a result of Hurricane Katrina which is anticipated to defer commencement of production to as late as the second quarter of 2006. Approximately 60 MMcfe per day of production net to our interest was shut-in initially as a result of the effects of Hurricane Rita in late September 2005. Approximately 53 MMcfe per day of production, or approximately 90% of our pre-hurricane production, was restored within two weeks of the hurricane. Our operated platforms appear to have sustained minimal damage attributable to the storm. First reports from operators of other facilities handling our production indicated varying degrees of damage to their facilities, the full extent of which may not be known for some time. Although a submersible rig engaged in drilling operations on our East Cameron Block 79 property was moved off location by Hurricane Rita, a substitute rig was subsequently provided, the damage to the well was repaired and drilling recommenced in the last quarter of 2005. Other planned operations also are delayed as a result of the effects of both hurricanes. We cannot estimate a range of loss arising from the hurricanes until we are able to more completely assess the impacts on our properties and the properties of our operational partners. Until we are able to complete all the repair work and submit costs to our insurance underwriters for review, the full extent of our insurance recovery and the resulting net cost to us for Hurricanes Katrina and Rita will be unknown. For the insurance period ending September 30, 2005, we carry a $3.0 million annual deductible and a $.375 million single occurrence deductible.

We entered into an agreement effective in October 2005 covering approximately 33,000 acres in West Texas, pursuant to which, upon closing, we acquired an approximate 35% working interest in approximately 200 existing producing wells effective November 1, 2005, and committed to drill an additional 150 wells within a four year period, funding $36.5 million of our partner s share of drilling costs for such 150-well drilling program. We will obtain an assignment of an approximate 35% working interest in the entire committed acreage upon completion of the 150-well program.

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The Offering

Common stock offered by selling stockholders	33,348,130 shares.
Use of proceeds	We will not receive any proceeds from the sale of the shares of common stock by the selling stockholders.
Listing	Our common stock has been approved for listing on the New York Stock Exchange, subject to the completion of our proposed merger with Forest Energy Resources, Inc.
Common stock split	Unless specifically indicated or the context requires otherwise, the share and per share information of this offering gives effect to a 21,556.61594 to 1 stock split, which was effected on March 3, 2005.
Dividend Policy	We do not expect to pay dividends in the near future.

Risk Factors

You should carefully consider all of the information contained in this prospectus prior to investing in the common stock. In particular, we urge you to carefully consider the information under Risk Factors, beginning on page 24 of this prospectus so that you understand the risks associated with an investment in our company and the common stock. These risks include the following:

- Oil and natural gas prices are volatile, and a decline in oil and natural gas prices would affect significantly our financial results and impede our growth.
- Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will affect materially the quantities and present value of our reserves.
- Unless we replace our oil and natural gas reserves, our reserves and production will decline.
- Relatively short production periods or reserve life for Gulf of Mexico properties subject us to higher reserve replacement needs and may impair our ability to replace production during periods of low oil and natural gas prices.

Corporate Information

We were incorporated in August 1983 as a Delaware corporation. We have three subsidiaries, Mariner LP LLC, a Delaware limited liability company, Mariner Energy Texas LP, a Delaware limited partnership, and MEI Sub, Inc., a Delaware corporation.

On March 2, 2004, Mariner was acquired by MEI Acquisitions Holdings, LLC, an affiliate of the private equity funds, Carlyle/ Riverstone Global Energy and Power Fund II, L.P. and ACON Investments LLC, through a merger of Mariner s former indirect parent with MEI. Prior to the merger, we were owned indirectly by Joint Energy Development Investments Limited Partnership (JEDI), which was an indirect wholly owned subsidiary of Enron Corp. As a result of the merger, we are no longer affiliated with Enron Corp. See Business Enron Related Matters.

In March 2005, we completed a private placement of 16,350,000 shares of our common stock to qualified institutional buyers, non-U.S. persons and accredited investors. Our former sole stockholder, MEI Acquisitions Holdings, LLC, also sold 15,102,500 shares of our common stock in the private placement. We used the net proceeds from the sale of 12,750,000 shares of our common stock to purchase and retire an equal number of shares of our common stock from our former sole stockholder. As a result, after the private placement an affiliate of our former sole stockholder beneficially owned 5.3% of our outstanding common stock. See Security Ownership of Certain Beneficial Owners and Management.

Our principal executive office is located at One Briar Lake Plaza, Suite 2000, 2000 West Sam Houston Parkway South, Houston, Texas 77042. Our telephone number is (713) 954-5500.

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Proposed Merger with Forest Energy Resources, Inc.

On September 9, 2005, we entered into a merger agreement with Forest Oil Corporation (which we refer to as Forest), Forest Energy Resources, Inc. (which we refer to as Forest Energy Resources), and MEI Sub, Inc. The consummation of the transactions contemplated by the merger agreement is subject to several conditions, including the adoption of the merger agreement by our stockholders. Accordingly, we cannot assure you that the merger and related transactions will ever be consummated. Our annual stockholder meeting, at which Mariner stockholders will vote to adopt the merger agreement, is scheduled to occur on March 2, 2006.

The following provides a summary of the material terms of the transactions contemplated by the merger agreement.

Overview of the Proposed Transactions

Forest has transferred and contributed the assets and certain liabilities associated with its offshore Gulf of Mexico operations to Forest Energy Resources, a newly formed subsidiary of Forest. Immediately prior to the merger, Forest will distribute all of the outstanding shares of Forest Energy Resources to Forest shareholders on a pro rata basis. Forest Energy Resources will then merge with a newly formed subsidiary of Mariner, and become a new wholly owned subsidiary of Mariner. When the merger is complete, approximately 58% of the Mariner common stock will be held by shareholders of Forest and approximately 42% of Mariner common stock will be held by the pre-merger stockholders of Mariner, each on a pro forma basis.

Following the merger, Mariner will:

- be an independent public company;
- own both the Mariner operations and the Forest Gulf of Mexico operations; and
- have total assets of approximately $2.1 billion and total debt of approximately $279.0 million on a pro forma combined basis, assuming the spin-off and the merger occurred on September 30, 2005.

About Forest and Forest Energy Resources

Forest is an independent oil and gas company engaged in the acquisition, exploration, development and production of natural gas and liquids in North America and selected international locations. Forest was incorporated in New York in 1924, as the successor to a company formed in 1916, and has been a publicly held company since 1969. Forest operates from offices located in Denver, Colorado; Lafayette and Metairie, Louisiana; Anchorage, Alaska; and Calgary, Alberta, Canada.

Forest Energy Resources is a wholly owned subsidiary of Forest. Forest Energy Resources was formed in Delaware on August 18, 2005 for the purpose of completing the spin-off of the Forest Gulf of Mexico operations. As of December 31, 2004, the Forest Gulf of Mexico operations that have been contributed to Forest Energy Resources had 339.7 Bcfe of estimated proved reserves, of which approximately 79% were natural gas and 21% were oil and condensate. As of December 31, 2004, the PV10 of the Forest Gulf of Mexico operations was approximately $1,222.2 million, and the standardized measure of discounted future net cash flows attributable to its estimated proved reserves was approximately $925.8 million. Please see The Forest Gulf of Mexico Operations Estimated Proved Reserves for a reconciliation of PV10 to the standardized measure of discounted future net cash flows. As of December 31, 2004, approximately 76% of the Forest Gulf of Mexico operations estimated proved reserves were classified as proved developed. For the year ended December 31, 2004, the Forest Gulf of Mexico operations total net production was 81.1 Bcfe. In the three-year period ended December 31, 2004, the Forest Gulf of Mexico operations deployed approximately $560 million of capital on acquisitions, exploration and development while adding approximately 182 Bcfe of estimated proved reserves and producing approximately 215 Bcfe.

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Transaction Structure

The following diagrams and accompanying descriptions serve to describe generally the transactions that will take place in connection with the spin-off and merger. For more information, please read The Spin-off and Merger.

1. Current Corporate Ownership Structure

Forest Energy Resources is a wholly owned subsidiary of Forest. MEI Sub is a wholly owned subsidiary of Mariner.

2. The Contribution and Spin-Off

Forest has contributed the assets and certain liabilities associated with its Gulf of Mexico operations to Forest Energy Resources. Forest will, immediately prior to the merger, distribute all of the shares of Forest Energy Resources to its shareholders on a pro rata basis.

3. The Merger

MEI Sub will merge with and into Forest Energy Resources, with Forest Energy Resources surviving as a wholly owned subsidiary of Mariner. Forest Energy Resources will be renamed Mariner Energy Resources, Inc. In conjunction with the merger, shares of Forest Energy Resources stock will automatically be converted into shares of Mariner stock.

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4. Corporate Ownership Structure following the Spin-Off and Merger

At the conclusion of the merger, Forest shareholders will own approximately 58% of Mariner and the stockholders of Mariner who owned shares prior to the merger will own the remaining approximately 42% of Mariner.

What Forest and Mariner Stockholders Will Receive

If the merger is completed, each Forest shareholder will ultimately receive shares of Mariner common stock. As a result of the spin-off, Forest shareholders will initially receive shares of Forest Energy Resources, which will then be converted in the merger into the right to receive shares of Mariner. After the merger, Forest shareholders will be entitled to receive approximately 0.8 shares of Mariner for each Forest share that they own. Forest shareholders will not be required to pay for the shares of Forest Energy Resources distributed in the spin-off transaction or the shares of Mariner issued in the merger.

Mariner stockholders will keep the shares of Mariner common stock they currently own, but will not receive any additional shares in the merger.

Proposal to Amend Mariner s Certificate of Incorporation

We are proposing to amend Mariner s certificate of incorporation to increase the number of authorized shares of stock from 90 million to 200 million, subject to completion of the merger. Mariner s certificate of incorporation currently does not authorize a sufficient number of shares of common stock to complete the merger. Mariner currently is authorized to issue 70 million shares of Mariner common stock and 20 million shares of Mariner preferred stock. As of February 1, 2006, approximately 35.6 million shares of Mariner common stock were issued and outstanding. Under the terms of the merger agreement, Mariner must issue approximately 50.6 million shares (representing approximately 0.8 shares of Mariner common stock for each share of Forest common stock) of common stock in the merger, which would result in approximately 86 million shares of Mariner common stock outstanding. Therefore, the number of authorized shares of Mariner common stock must be increased in order to complete the merger.

Recommendation of Mariner s Board of Directors

The Mariner board of directors has determined that the merger is fair to and in the best interests of Mariner and its stockholders, and that the merger agreement is advisable. The Mariner board of directors has unanimously approved the merger agreement and the other proposals and recommends that the Mariner stockholders vote for the adoption of the merger agreement and the other proposals. A more detailed description of the background and reasons for the merger is set forth under The Spin-Off and Merger beginning on page 95.

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When considering the recommendations of the Mariner board of directors, you should be aware that the directors and executive officers of Mariner have interests and arrangements that may be different from your interests as stockholders, including:

arrangements regarding the appointment of directors and officers of Mariner following the merger; and

arrangements whereby the executive officers of Mariner will receive a cash payment of $1,000 each in exchange for the waiver of certain rights under their employment agreements, including the automatic vesting or acceleration of restricted stock and options upon the completion of the merger and the right to receive a lump sum cash payment if the officer voluntarily terminates employment without good reason within nine months following the completion of the merger.

At the close of business on February 1, 2006, directors and executive officers of Mariner and their affiliates as a group beneficially owned and were entitled to vote approximately 3.7 million shares of Mariner common stock (including restricted stock subject to vesting), representing approximately 10.4% of the shares of Mariner common stock outstanding on that date. All of the directors and executive officers of Mariner who are entitled to vote at the annual meeting of stockholders have indicated that they intend to vote their shares of Mariner common stock in favor of adoption of the merger agreement.

In reaching its decision on the merger, the Mariner board of directors considered a number of factors, including the following among others:

the increased size of the combined company could reduce volatility and allow it to participate in larger scale drilling projects and acquisition opportunities;

the merger would be expected to increase Mariner s estimated proved reserves and undeveloped acreage;

the merger could generate increased visibility in the capital markets and trading liquidity for the combined company;

the merger would increase the number of Mariner s producing fields, thereby reducing Mariner s dependence on a concentrated number of properties;

the merger would be consummated only if approved by the holders of a majority of the Mariner common stock; and

the merger is structured as a tax-free reorganization for U.S. federal income tax purposes and, accordingly, would not be taxable either to Mariner or its stockholders.

The Mariner board of directors also identified and considered some risks and potential disadvantages associated with the merger, including, among others, the following:

the risk that there may be difficulties in combining the business of Mariner and the Forest Gulf of Mexico operations;

the risk that the potential benefits sought in the merger might not be fully realized;

the risk that the proved undeveloped, probable and possible reserves of the Forest Gulf of Mexico operations may never be converted to proved developed reserves; and

the fact that, in order to preserve the tax-free treatment of the spin-off, Mariner would be required to abide by restrictions that could reduce its ability to engage in certain business transactions.

In the judgment of the Mariner board of directors, the potential benefits of the merger outweigh the risks and the potential disadvantages.

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Opinion of Mariner s Financial Advisor

Lehman Brothers Inc., Mariner s financial advisor, has delivered to Mariner s board of directors a written opinion that, as of September 9, 2005, based upon and subject to the factors and assumptions set forth in the opinion, the exchange ratio in the merger was fair from a financial point of view to Mariner.

Directors and Officers of Mariner Following the Merger

If the merger is completed, Mariner s board will consist of seven members, five of whom will be the current directors of Mariner, and two of whom will be mutually agreed between Mariner and Forest prior to the completion of the merger. The Chairman of the Mariner board will be Mr. Scott D. Josey, the current Chairman, Chief Executive Officer and President of Mariner. The two Mariner directors to be mutually agreed by Forest and Mariner pursuant to the terms of the merger agreement have not yet been designated.

The current executive officers of Mariner will remain in their current positions following the merger.

Material United States Federal Tax Consequences of the Merger

It is a condition to the completion of the merger that Forest, Forest Energy Resources and Mariner receive opinions from their respective tax counsels to the effect that the merger will constitute a tax-free reorganization for U.S. federal income tax purposes. As a tax-free reorganization for U.S. federal income tax purposes, the merger will be tax-free to the stockholders of Mariner and tax-free to the shareholders of Forest, except for cash received in lieu of fractional shares of Mariner for shares of Forest Energy Resources.

We encourage you to consult your own tax advisor for a full understanding of the tax consequences of the merger to you.

Conditions to the Completion of the Merger

The merger will be completed only if certain conditions, including the following, are satisfied (or waived in certain cases):

- the adoption of the merger agreement by Mariner stockholders holding a majority of the Mariner common stock and the approval of the proposed amendment to Mariner s certificate of incorporation;
- the absence of legal restrictions that would prevent the completion of the transactions;
- the receipt by Forest, Mariner and Forest Energy Resources of an opinion from their respective counsel to the effect that the merger will be treated as a reorganization for federal income tax purposes;
- the completion of the spin-off in accordance with the distribution agreement;
- the receipt of material consents, approvals and authorizations of governmental authorities;
- the expiration or termination of any applicable waiting period under the Hart-Scott-Rodino Act;
- the SEC declaring effective the registration statements of Mariner relating to the shares of Mariner common stock to be issued in the merger and those shares held by its existing stockholders;
- the representations and warranties contained in the merger agreement being materially true and correct, and the performance in all material respects by the parties of their covenants and other agreements in the merger agreement;
- the approval for listing on the New York Stock Exchange or Nasdaq of Mariner s common stock; and

Mariner and Forest receiving the consents required pursuant to their credit facilities (with Mariner or Forest Energy Resources having entered into a new or amended credit facility sufficient to operate the combined businesses), and Forest receiving any consents required from its bondholders.

On November 14, 2005, the waiting period under the Hart-Scott-Rodino Act with respect to the merger expired. On October 19, 2005, Forest received the consent required pursuant to its credit facility. On February 7, 2006, Mariner s common stock was approved for listing on the New York Stock Exchange upon the completion of the merger. As of February 7, 2006, no other conditions to closing have been satisfied. Mariner is currently negotiating the definitive documents for its new credit facility, which documents also will grant the consent required pursuant to its existing facility. Mariner and Forest are actively working to obtain necessary consents, approvals and authorizations from governmental authorities, including the Minerals Management Service.

Based on its current valuation of the Forest Gulf of Mexico operations and the current amount of distributions permitted by the covenants contained in the indentures governing Forest s outstanding bonds, Forest believes that no consents of its bondholders will be required for the spin-off and the merger. If Forest s belief that bondholder consents are not necessary remains unchanged as the merger closing approaches, it intends to waive conditions in the merger agreement and distribution agreement related to such consents.

Neither Mariner nor Forest currently believes that any other condition to closing is likely to be waived.

Pursuant to the terms of the merger agreement, the closing of the merger will occur as promptly as practicable, and in no event later than the second business day following the satisfaction or, if permissible, waiver of the conditions to closing set forth in the merger agreement, or at such other time as Mariner and Forest Energy Resources mutually agree. Unless Mariner consents otherwise, the closing will not occur earlier than the fifth business day following the record date for the spin-off.

Termination of the Merger Agreement

Forest and Mariner may mutually agree to terminate the merger agreement without completing the merger. In addition, either party may terminate the merger agreement if:

- the other party breaches its representations, warranties, covenants or agreements under the merger agreement so as to create a material adverse effect, and the breach has not been cured within 30 days after notice was given of such breach;
- the parties do not complete the merger by March 31, 2006;
- a governmental order prohibits the merger; or
- Mariner does not receive the required approval of its stockholders.

In addition, Mariner may terminate the merger agreement if it receives a proposal to acquire Mariner that Mariner s board of directors determines in good faith to be more favorable to Mariner s stockholders than the merger. Forest may terminate the merger agreement if Mariner s board of directors withdraws or modifies its approval of the merger to Mariner s stockholders.

Termination Fee and Expenses

Mariner must pay Forest a termination fee of $25 million and out-of-pocket fees and expenses of up to $5 million if Mariner terminates the merger agreement to accept an alternative proposal that Mariner s board of directors determines in good faith to be more favorable to Mariner s stockholders than the merger. In addition, Mariner must pay Forest a termination fee of $25 million and reimbursement of out-of-pocket fees and expenses of up to $5 million if the merger agreement is terminated for the other reasons set forth under The Merger Agreement Termination Fees and Expenses on page 130.

Financing Arrangements Relating to the Spin-Off and the Merger

At the closing of the merger Mariner and Mariner Energy Resources expect to enter into a new $500 million senior secured revolving credit facility, and Mariner will enter into an additional $40 million senior secured letter of credit facility. The revolving credit facility will mature on the fourth anniversary of the closing, and the letter of credit facility will mature on the third anniversary of the closing. The outstanding principal balance of loans under the revolving credit facility may not exceed the borrowing base, which will be initially set at $400 million. In addition, Forest Energy Resources expects to enter into a new senior term loan facility in connection with the spin-off, which facility is expected to be repaid with borrowings under Mariner s and Mariner Energy Resources $500 million revolving credit facility.

Ancillary Agreements

In addition to the merger agreement and the distribution agreement, Forest, Forest Energy Resources and Mariner have entered into a tax sharing agreement relating to the allocation of certain tax liabilities. See Ancillary Agreements Tax Sharing Agreement beginning on page 135. In addition, Forest and Forest Energy Resources have entered into an employee benefits agreement addressing certain benefits matters for former Forest employees who become employees of Forest Energy Resources in connection with the spin-off and the merger. See Ancillary Agreements Employee Benefits Agreement beginning on page 136. Finally, Forest and Forest Energy Resources have entered into a transition services agreement under which Forest will provide certain services to Forest Energy Resources for a limited period of time following the merger. See Ancillary Agreements Transition Services Agreement beginning on page 137.

Regulatory Matters

None of the parties is aware of any other material governmental or regulatory approval required for the completion of the merger, other than the effectiveness of the registration statement of which this prospectus is a part and the effectiveness of Mariner s registration statement on Form S-4 relating to the shares of Mariner common stock to be issued to Forest shareholders in the merger, and compliance with applicable antitrust law (including the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended) and the corporate law of the State of Delaware. On November 14, 2005, the waiting period under the Hart-Scott-Rodino Act with respect to the merger expired.

Mariner Stockholder Vote

Our annual stockholder meeting, at which Mariner stockholders will vote to adopt the merger agreement, is scheduled to occur on Thursday, March 2, 2006. For the merger to occur, the holders of a majority of the outstanding Mariner common stock must adopt the merger agreement and approve the amendment to the certificate of incorporation. Mariner stockholders will have one vote for each share of Mariner common stock they own. On February 1, 2006, the record date for Mariner s annual meeting, 35,615,400 shares of Mariner common stock were issued and outstanding and entitled to vote at the meeting. The approval of Forest shareholders is not required for the spin-off or the merger.

Closing of the Transactions

If the merger agreement and the proposed amendment to the certificate of incorporation are adopted and approved by the stockholders of Mariner, then Mariner, Forest, Forest Energy Resources and MEI Sub expect to complete the spin-off and the merger as soon as possible after the satisfaction (or waiver, where permissible) of the other conditions to the spin-off and the merger. We currently anticipate that the merger will be completed during the first calendar quarter of 2006.

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SUMMARY SELECTED HISTORICAL AND PRO FORMA FINANCIAL DATA

Sources of Information

The following is summary selected consolidated financial data of Mariner and selected consolidated financial data of the Forest Gulf of Mexico operations. We derived this information from the audited and unaudited financial statements for Mariner and from the audited and unaudited statements of revenues and direct operating expenses of the Forest Gulf of Mexico operations for the periods presented. You should read this information in conjunction with the financial information included elsewhere in this prospectus. See Index to Financial Statements on page F-1 and Unaudited Pro Forma Combined Condensed Financial Information beginning on page 44.

How We Prepared the Unaudited Pro Forma Combined Condensed Financial Information

The unaudited pro forma combined condensed financial information is presented to show you how Mariner might have looked if the Forest Gulf of Mexico operations had been an independent company and combined with Mariner for the periods presented. We prepared the pro forma financial information using the purchase method of accounting, with Mariner treated as the acquiror. See The Spin-Off and Merger Accounting Treatment beginning on page 117.

If the Forest Gulf of Mexico operations had been an independent company, and if Mariner and the Forest Gulf of Mexico operations had been combined in the past, they might have performed differently. You should not rely on the pro forma financial information as an indication of the financial position or results of operations that Mariner would have reported if the spin-off and merger had taken place earlier or of the future results that Mariner will achieve after the merger. See Unaudited Pro Forma Combined Condensed Financial Information beginning on page 44.

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Summary Historical Consolidated Financial Data of Mariner

The following table shows Mariner s summary historical consolidated financial data as of and for each of the four years ended December 31, 2003, the period from January 1, 2004 through March 2, 2004, the period from March 3, 2004 through December 31, 2004, the period from March 3, 2004 through September 30, 2004 and the nine-month period ended September 30, 2005. The summary historical consolidated financial data as of and for the four years ended December 31, 2003, the period from January 1, 2004 through March 2, 2004 and the period from March 3, 2004 through December 31, 2004 are derived from Mariner s audited financial statements included herein, and the summary historical consolidated financial data for the period from March 3, 2004 through September 30, 2004 and the nine-month period ended September 30, 2005 are derived from unaudited financial statements of Mariner. You should read the following data in connection with Management s Discussion and Analysis of Financial Condition and Results of Operations and the consolidated financial statements included elsewhere in this prospectus, where there is additional disclosure regarding the information in the following table, including pro forma information regarding the merger. Mariner s historical results are not necessarily indicative of results to be expected in future periods.

On March 2, 2004, Mariner s former indirect parent, Mariner Energy LLC, merged with MEI Acquisitions, LLC, an affiliate of the private equity funds, Carlyle/ Riverstone Global Energy and Power Fund II, L.P. and ACON Investments LLC. The financial information contained herein is presented in the style of Pre-2004 Merger activity (for all periods prior to March 2, 2004) and Post-2004 Merger activity (for the March 3, 2004 through December 31, 2004 period and the March 3, 2004 through September 30, 2004 period) to reflect the impact of the restatement of assets and liabilities to fair value as required by push-down purchase accounting at the March 2, 2004 merger date.

	Post-2004 Merger			Pre-2004 Merger				
	Nine Months Ended September 30, 2005	Period from March 3, 2004 through September 30, 2004	Period from March 3, 2004 through December 31, 2004	Period from January 1, 2004 through March 2, 2004	Year Ended December 31, 2003	2002	2001	2000
	(in millions, except per share data)							
Statement of Operations Data:								
Total revenues(1)	$ 151.2	$ 122.5	$ 174.4	$ 39.8	$ 142.5	$ 158.2	$ 155.0	$ 121.1
Lease operating expenses	20.2	15.1	21.4	4.1	24.7	26.1	20.1	17.2
Transportation expenses	1.7	3.7	1.9	1.1	6.3	10.5	12.0	7.8
Depreciation, depletion and amortization	43.4	37.4	54.3	10.6	48.3	70.8	63.5	56.8
Impairment of production equipment held for use	0.5	1.0	1.0					
					3.2			

Derivative settlement								
Impairment of Enron related receivables						3.2	29.5	
General and administrative expenses	26.7	6.2	7.6	1.1	8.1	7.7	9.3	6.5
Operating income	58.7	59.1	88.2	22.9	51.9	39.9	20.6	32.8
Interest income	0.7	0.2	0.2	0.1	0.8	0.4	0.7	0.1
Interest expense	(5.4)	(4.4)	(6.0)		(7.0)	(10.3)	(8.9)	(11.0)
Income before income taxes	54.0	54.9	82.4	23.0	45.7	30.0	12.4	21.9
Provision for income taxes	(18.4)	(19.2)	(28.8)	(8.1)	(9.4)			
Income before cumulative effect of change in accounting method net of tax effects	35.6	35.7	53.6	14.9	36.3	30.0	12.4	21.9
Income before cumulative effect per common share								
Basic	1.10	1.20	1.80	.50	1.22	1.01	.42	.74
Diluted	1.07	1.20	1.80	.50	1.22	1.01	.42	.74
Cumulative effect of changes in accounting method					1.9			
Net income	$ 35.6	$ 35.7	$ 53.6	$ 14.9	$ 38.2	$ 30.0	$ 12.4	$ 21.9
Net income per common share								
Basic	1.10	1.20	1.80	.50	1.29	1.01	.42	.74
Diluted	1.07	1.20	1.80	.50	1.29	1.01	.42	.74
Capital Expenditure and Disposal Data:								
Exploration, including leasehold/seismic	$ 23.6	$ 35.7	$ 40.4	$ 7.5	$ 31.6	$ 40.4	$ 66.3	$ 46.7
Development and other	106.8	50.2	93.2	7.8	51.7	65.7	98.2	61.4
Proceeds from property conveyances					(121.6)	(52.3)	(90.5)	(29.0)
	$ 130.4	$ 85.9	$ 133.6	$ 15.3	$ (38.3)	$ 53.8	$ 74.0	$ 79.1

Total capital expenditures net of proceeds from property conveyances	

(1) Includes effects of hedging.

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	Post-2004 Merger		Pre-2004 Merger			
			December 31,			
	September 30, 2005	December 31, 2004	2003	2002	2001	2000
	(in millions)					
Balance Sheet Data:(1)						
Property and equipment, net, full cost method	$ 393.3	$ 303.8	$ 207.9	$ 287.6	$ 290.6	$ 287.8
Total assets	502.2	376.0	312.1	360.2	363.9	335.4
Long-term debt, less current maturities	79.0	115.0		99.8	99.8	129.7
Stockholder s equity	178.6	133.9	218.2	170.1	180.1	141.9
Working capital (deficit)(2)	(30.2)	(18.7)	38.3	(24.4)	(19.6)	(15.4)

(1) Balance sheet data as of December 31, 2004 reflects purchase accounting adjustments to oil and gas properties, total assets and stockholder s equity resulting from the acquisition of our former indirect parent on March 2, 2004.

(2) Working capital (deficit) excludes current derivative assets and liabilities, deferred tax assets and restricted cash.

	Post-2004 Merger			Pre-2004 Merger				
	Nine Months Ended September 30, 2005	Period from March 3, 2004 through September 30, 2004	Period from March 3, 2004 through December 31, 2004	Period from January 1, 2004 through March 2, 2004	Year Ended December 31, 2003	2002	2001	2000
	(in millions)							
Other Financial Data:								
EBITDA(1)	$ 102.7	$ 97.5	$ 143.5	$ 33.4	$ 100.3	$ 113.9	$ 113.6	$ 89.6
Net cash provided by operating activities	135.4	96.8	135.9	20.3	103.5	60.3	113.5	63.9
Net cash (used) provided by investing activities	(142.1)	(85.9)	(133.6)	(15.3)	38.3	(53.8)	(74.0)	(79.1)
Net cash (used) provided by financing activities	8.7	(74.9)	64.9		(100.0)		(30.0)	17.4
Reconciliation of Non-GAAP Measures:								
EBITDA(1)	$ 102.7	$ 97.5	$ 143.5	$ 33.4	$ 100.3	$ 113.9	$ 113.6	$ 89.6
	25.1	9.7	6.9	(13.2)	21.8	(20.4)	7.5	(15.5)

Changes in working capital								
Non-cash hedge gain(2)	(3.6)	(5.1)	(7.9)		(2.0)	(23.2)		
Amortization/other	0.9	0.5	0.8			(0.1)	0.6	0.7
Stock compensation expense	17.6							
Net interest expense	(4.7)	(4.2)	(5.8)	0.1	(6.2)	(9.9)	(8.2)	(10.9)
Income tax expense	(2.6)	(1.6)	(1.6)		(10.4)			
Net cash provided by operating activities	$ 135.4	$ 96.8	$ 135.9	$ 20.3	$ 103.5	$ 60.3	$ 113.5	$ 63.9

(1) EBITDA means earnings before interest, income taxes, depreciation, depletion and amortization. For the nine months ended September 30, 2005, EBITDA includes $17.6 million in non-cash stock compensation expense related to restricted stock and stock options granted in 2005. We believe that EBITDA is a widely accepted financial indicator that provides additional information about our ability to meet our future requirements for debt service, capital expenditures and working capital, but EBITDA should not be considered in isolation or as a substitute for net income, operating income, net cash provided by operating activities or any other measure of financial performance presented in

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accordance with generally accepted accounting principles or as a measure of a company s profitability or liquidity.

(2) In accordance with SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities, as amended by SFAS No. 137 and No. 138, we de-designated our contracts effective December 2, 2001 after the counterparty (an affiliate of Enron Corp.) filed for bankruptcy and recognized all market value changes subsequent to such de-designation in our earnings. The value recorded up to the time of de-designation and included in Accumulated Other Comprehensive Income (AOCI), has reversed out of AOCI and into earnings as the original corresponding production, as hedged by the contracts, is produced. We have designated subsequent hedge contracts as cash flow hedges with gains and losses resulting from the transactions recorded at market value in AOCI, as appropriate, until recognized as operating income in our Statement of Operations as the physical production hedged by the contracts is delivered.

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Summary Selected Consolidated Statements of Revenues and Direct Operating Expenses of the Forest Gulf of Mexico Operations

The summary selected financial data for the Forest Gulf of Mexico operations for the nine months ended September 30, 2005 and 2004 and the years ended December 31, 2004, 2003 and 2002 were derived from the historical records of Forest. You should read the following data in connection with Management s Discussion and Analysis of Financial Condition and Results of Operations of the Forest Gulf of Mexico Operations and the consolidated statements of revenues and direct operating expenses of the Forest Gulf of Mexico operations included elsewhere in this prospectus. Complete financial and operating information related to the Forest Gulf of Mexico operations, including balance sheet and cash flow information, are not presented below because the Forest Gulf of Mexico operations were not maintained as a separate business unit, and therefore the assets, liabilities or indirect operating costs applicable to the operations were not segregated.

	Nine Months Ended September 30,		Years Ended December 31		
	2005	**2004**	**2004**	**2003**	**2002**
	(in millions, except production data)				
Statement of Operations Data:					
Oil and natural gas revenues(1)	$ 326.7	$ 324.4	$ 453.1	$ 342.0	$ 228.9
Direct Operating Expenses:					
Lease operating expenses	57.4	63.0	80.1	45.7	52.1
Transportation	2.5	1.4	2.2	2.7	3.8
Production taxes	1.9	1.2	1.5	1.5	1.0
Total direct operating expenses	61.8	65.6	83.8	49.9	56.9
Revenues in excess of direct operating expenses	$ 264.9	$ 258.8	$ 369.3	$ 292.1	$ 172.0
Summary Production Data:					
Production Data:					
Natural gas (MMcf)	41,442	46,036	61,684	58,785	50,566
Oil and condensate (MBbls)	1,845	2,004	2,624	2,143	1,974
Natural gas liquids (MBbls)	628	186	606	2	6
Total (MMcfe)	56,280	59,176	81,064	71,655	62,446
Per day (MMcfe)	206	216	221	196	171
Average realized sales price per unit:					
Natural gas ($/Mcf):					
Sales price received	$ 7.14	$ 6.02	$ 6.30	$ 5.41	$ 3.39
Effects of hedging	(1.13)	(0.45)	(0.56)	(0.63)	0.17
Net sales price received	6.01	5.57	5.74	4.78	3.56

	Nine Months Ended September 30,		Years Ended December 31		
	2005	2004	2004	2003	2002
	(in millions, except production data)				
Oil ($/bbl):					
Sales price received	$ 51.97	$ 38.13	$ 40.06	$ 30.19	$ 24.85
Effects of hedging	(19.95)	(6.61)	(8.55)	(1.90)	
Net sales price received	32.02	31.52	31.51	28.29	24.85
Natural gas liquids ($/bbl):					
Sales price received	$ 29.54	$ 25.40	$ 27.28	$ 19.00	$ 12.33
Average realized sales price per Mcfe (including effects of hedging) ($/Mcfe)	$ 5.81	$ 5.48	$ 5.59	$ 4.77	$ 3.67
Production costs per Mcfe:					
Lease operating expenses	$ 1.02	1.06	0.99	0.64	0.83
Transportation	$ 0.04	0.02	0.03	0.04	0.06
Production taxes	$ 0.03	0.02	0.02	0.02	0.02

(1) Includes effects of hedging.

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Summary Selected Unaudited Pro Forma Combined Condensed Financial Information

The following summary selected unaudited pro forma combined condensed financial information has been prepared to reflect the proposed merger. This unaudited pro forma combined condensed financial information is based on the historical financial statements of Mariner and the historical statements of revenues and direct operating expenses of the Forest Gulf of Mexico operations, all of which are included in this prospectus, and the estimates and assumptions set forth in the Notes to the Unaudited Pro Forma Combined Condensed Financial Information beginning on page 44. The unaudited pro forma combined condensed operating results give effect to the merger as if it had occurred on January 1, 2004. The unaudited pro forma combined condensed balance sheet gives effect to the merger as if it had occurred on September 30, 2005.

The unaudited pro forma combined condensed financial information is for illustrative purposes only. The financial results may have been different had the Forest Gulf of Mexico operations been an independent company and had the companies always been combined. You should not rely on the unaudited pro forma combined condensed financial information as being indicative of the historical results that would have been achieved had the merger occurred in the past or the future financial results that Mariner will achieve after the merger.

The merger will be accounted for using the purchase method of accounting, with Mariner treated as the acquiror. In addition, the purchase price allocation is preliminary and will be finalized following the closing of the merger. The final purchase price allocation will be determined after closing based on the actual fair value of current assets, current liabilities, indebtedness, long-term liabilities, proven and unproven oil and gas properties, identifiable intangible assets and unvested stock options that are outstanding at closing. We are continuing to evaluate all of these items; accordingly, the final purchase price may differ in material respects from that presented in the unaudited pro forma combined condensed balance sheet.

	As of and for the Nine Months Ended September 30, 2005	For the Year Ended December 31, 2004
	(in thousands, except per share and proved reserve data)	
OPERATING RESULTS:		
Revenues	$ 477,967	$ 667,326
Net income	$ 71,221	$ 106,298
Earnings per share		
Basic	$ 0.86	$ 1.32
Diluted	$ 0.85	$ 1.32
Weighted average shares outstanding		
Basic	83,075	80,385
Diluted	83,950	80,385
BALANCE SHEET DATA:		
Total assets	$ 2,118,526	
Total debt	$ 279,000	
Stockholders equity	$ 1,152,134	

	As of June 30, 2005	As of December 31, 2004

ESTIMATED PROVED RESERVES:		
Oil (MBbls)*	29,261	25,905
Gas (MMcf)	423,352	421,741
Equivalent (MMcfe)	598,918	577,173
Proved developed percentage	63.9%	63.7%

* Includes 3,285.6 MBbls of natural gas liquids.

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Comparative Per Share Data

The following table presents historical per share data of Mariner common stock and combined per share data of Mariner and the Forest Gulf of Mexico operations on an unaudited pro forma basis after giving effect to the spin-off and the merger. The merger will be accounted for using the purchase method of accounting, with Mariner treated as the acquiror. The combined pro forma per share data was derived from the Unaudited Pro Forma Combined Condensed Financial Information as presented beginning on page 44. The assumptions related to the preparation of the Unaudited Pro Forma Combined Condensed Financial Information are described beginning at page 44. The data presented below should be read in conjunction with the historical consolidated financial statements of Mariner and the historical statements of revenues and direct operating expenses of the Forest Gulf of Mexico operations included elsewhere in this prospectus.

The Mariner unaudited pro forma equivalent data was calculated with reference to the total number of shares of Mariner common stock expected to be outstanding after the merger, including the shares to be issued to Forest shareholders and the currently-outstanding shares of Mariner common stock.

The pro forma combined per share data may not be indicative of the operating results or financial position that would have occurred if the merger had been consummated at the beginning of the periods indicated, and may not be indicative of future operating results or financial position.

	Mariner	
	Historical	**Combined Pro Forma**
Earnings per share		
Nine months ended September 30, 2005(1)		
Basic	$ 1.10	$ 0.86
Diluted	$ 1.07	$ 0.85
Year ended December 31, 2004(2)		
Basic	$ 2.30	$ 1.32
Diluted	$ 2.30	$ 1.32
Book Value per share As of September 30, 2005(3)	$ 5.01	$ 13.36
Cash dividends declared per common share	$	$

(1) Mariner s historical basic and diluted earnings per share calculation for the nine months ended September 30, 2005 assumes Mariner had 32,438,240 and 33,312,831 weighted average shares of common stock outstanding, respectively. Mariner s pro forma basic and diluted earnings per share calculation for the nine months ended September 30, 2005 assumes Mariner had 83,075,250 and 83,949,841 weighted average shares of common stock outstanding, respectively.

(2) Mariner s historical basic and diluted earnings per share calculation for the year ended December 31, 2004 assumes Mariner had 29,748,130 and 29,748,130 weighted average shares of common stock outstanding, respectively. Mariner s pro forma basic and diluted earnings per share calculation for the year ended December 31, 2004 assumes Mariner had 80,385,140 and 80,385,140 weighted average shares of common stock outstanding, respectively.

(3) Book value per share calculation assumes that Mariner had 35,615,400 shares of common stock outstanding and 86,252,410 combined pro forma shares of common stock outstanding as of September 30, 2005.

Summary Financial and Operational Data for the Year Ended December 31, 2005

Set forth below is summary financial and operational data for the year ended December 31, 2005 for Mariner and for the Forest Gulf of Mexico operations. This information represents the estimates of Mariner s and Forest s respective management teams as of the date of this prospectus, but you should be aware that this information has not been audited by Mariner s and Forest s independent auditors. Neither Mariner s nor Forest s independent auditors, nor any other independent accountants, have compiled, examined or performed any procedures with respect to the information set forth below, nor have they expressed any opinion or any other form of assurance on such information.

For Mariner:

	Year Ended December 31, 2005
Statement of Operations Data:	
Total revenues(1)	$ 199.7
Direct operating expenses	32.2
Revenues in excess of direct operating expenses	$ 167.5
Summary Production Data:	
Production Data:	
Natural gas (MMcf)	18,354
Oil (MBbls)	1,791
Total (MMcfe)	29,098
Per day (MMcfe)	80
Average realized sales price per unit:	
Natural gas ($/Mcf):	
Sales price received	$ 8.33
Effects of hedging	(1.67)
Net sales price received	$ 6.66
Oil ($/bbl):	
Sales price received	$ 51.66
Effects of hedging	(10.43)
Net sales price received	$ 41.23
Average realized sales price per Mcfe (including effects of hedging) ($/Mcfe)	$ 6.74
Estimated Proved Reserves as of December 31, 2005:	
Oil (MBbls)	21,647
Gas (MMcf)	207,686
Equivalent (MMcfe)	337,568
Estimated Daily Production Rate as of December 31, 2005: 75 MMcfe	

(1) Includes effects of hedging.

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For the Forest Gulf of Mexico Operations:

	Year Ended December 31, 2005
Summary Production Data:	
Production Data:	
Natural gas (MMcf)	49,120
Oil and condensate (MBbls)	2,070
Natural gas liquids (MBbls)	713
Total (MMcfe)	65,818
Per day (MMcfe)	180
Estimated Proved Reserves as of December 31, 2005:	
Oil and condensate (MBbls)	9,271
Gas (MMcf)	231,142
Natural gas liquids (MBbls)	3,223
Equivalent (MMcfe)	306,105

Estimated Daily Production Rate as of December 31, 2005: 130 MMcfe

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Comparative Stock Price and Dividends

In March 2005, Mariner completed a private placement of 16,350,000 shares of its common stock to qualified institutional buyers, non-U.S. persons and accredited investors. There is no established public trading market for the shares of Mariner common stock, and it is not expected that a public trading market will be established until the completion of the merger. The shares of Mariner s common stock issued to qualified institutional buyers in connection with its March 2005 private equity placement are eligible for the PORTAL Market®.

Forest Energy Resources was incorporated as a wholly owned subsidiary of Forest in August 2005. There is no established public trading market for the shares of Forest Energy Resources common stock.

Mariner has not paid any cash dividends on its shares of common stock for the fiscal years 2003, 2004 or 2005, and it anticipates that it will not pay any dividends in 2006. Forest Energy Resources has not paid any cash dividends on its shares of common stock for the fiscal year 2005, and it anticipates that it will not pay any dividends in 2006. The payment of any dividends by Mariner prior to the merger is subject to the limitations included in the merger agreement and in its credit facility, and following the merger the payment of dividends by Mariner and Forest Energy Resources will be subject to restrictions included in their credit facilities.

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RISK FACTORS

You should consider carefully the following risk factors, which we believe include all material risks associated with our business, the merger, and the offering of our common stock, together with all of the other information included in this prospectus, before deciding to invest in our common stock. Realization of any of the following risks could have a material adverse effect on our business, financial condition, cash flows and results of operations. In that case, the trading price of our common stock could decline and you could lose all or part of your investment.

Risks Related to our Business and to the Combined Operations After the Merger

Oil and natural gas prices are volatile, and a decline in oil and natural gas prices would reduce our revenues, profitability and cash flow and impede our growth.

Our revenues, profitability and cash flow depend substantially upon the prices and demand for oil and natural gas. The markets for these commodities are volatile and even relatively modest drops in prices can affect significantly our financial results and impede our growth. Oil and natural gas prices are currently at or near historical highs and may fluctuate and decline significantly in the near future. Prices for oil and natural gas fluctuate in response to relatively minor changes in the supply and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control, such as:

- domestic and foreign supply of oil and natural gas;
- price and quantity of foreign imports;
- actions of the Organization of Petroleum Exporting Countries and other state-controlled oil companies relating to oil price and production controls;
- level of consumer product demand;
- domestic and foreign governmental regulations;
- political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;
- weather conditions;
- technological advances affecting oil and natural gas consumption;
- overall U.S. and global economic conditions; and
- price and availability of alternative fuels.

Further, oil prices and natural gas prices do not necessarily fluctuate in direct relationship to each other. Because approximately 64% of our estimated proved reserves as of December 31, 2004 (73% on a pro forma basis, including reserves of the Forest Gulf of Mexico operations) were natural gas reserves, our financial results are more sensitive to movements in natural gas prices. Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil and natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves and could have a material adverse effect on our financial condition and results of operations.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will affect materially the quantities and present value of our reserves and the reserves of the Forest Gulf of Mexico operations, which may lower our bank borrowing base and reduce our access to capital.

Estimating oil and natural gas reserves is complex and inherently imprecise. It requires interpretation of the available technical data and making many assumptions about future conditions, including price and other economic conditions. In preparing estimates we and Forest project production rates and timing of development expenditures. We and Forest also analyze the available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. This process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our and Forest s estimates, perhaps significantly. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control. At December 31, 2004, 54% of our proved reserves (36% on a pro forma basis, including reserves of the Forest Gulf of Mexico operations) were proved undeveloped.

If the interpretations or assumptions we use in arriving at our estimates prove to be inaccurate, the amount of oil and natural gas that we ultimately recover may differ materially from the estimated quantities and net present value of reserves shown in this prospectus. See Business Estimated Proved Reserves for information about our oil and gas reserves and The Forest Gulf of Mexico Operations Estimated Proved Reserves for more information about the oil and gas reserves of the Forest Gulf of Mexico operations.

In estimating future net revenues from proved reserves, we and Forest assume that future prices and costs are fixed and apply a fixed discount factor. If these assumptions or discount factor are materially inaccurate, our revenues, profitability and cash flow could be materially less than our estimates.

The present value of future net revenues from our proved reserves and the proved reserves of the Forest Gulf of Mexico operations referred to in this prospectus is not necessarily the actual current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we and Forest base the estimated discounted future net cash flows from our proved reserves and the proved reserves of the Forest Gulf of Mexico operations on fixed prices and costs as of the date of the estimate. Actual future prices and costs fluctuate over time and may differ materially from those used in the present value estimate. In addition, discounted future net cash flows are estimated assuming that royalties to the MMS with respect to our affected offshore Gulf of Mexico properties will be paid or suspended for the life of the properties based upon oil and natural gas prices as of the date of the estimate. See Business Royalty Relief. Since actual future prices fluctuate over time, royalties may be required to be paid for various portions of the life of the properties and suspended for other portions of the life of the properties.

The timing of both the production and expenses from the development and production of oil and natural gas properties will affect both the timing of actual future net cash flows from our proved reserves and the proved reserves of the Forest Gulf of Mexico operations and their present value. In addition, the 10% discount factor that we and Forest use to calculate the net present value of future net cash flows for reporting purposes in accordance with the SEC s rules may not necessarily be the most appropriate discount factor. The effective interest rate at various times and the risks associated with our business or the oil and gas industry in general will affect the appropriateness of the 10% discount factor in arriving at an accurate net present value of future net cash flows.

Unless we replace our oil and natural gas reserves, our reserves and production will decline.

Our future oil and natural gas production depends on our success in finding or acquiring additional reserves. If we fail to replace reserves through drilling or acquisitions, our level of production and cash flows will be affected adversely. In general, production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves decline as reserves are produced unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both. Our ability to make the necessary capital investment to maintain or expand our asset base of oil and natural gas reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves.

Relatively short production periods or reserve life for Gulf of Mexico properties subjects us to higher reserve replacement needs and may impair our ability to replace production during periods of low oil and natural gas prices.

Due to high production rates, production of reserves from reservoirs in the Gulf of Mexico generally declines more rapidly than from reservoirs in other producing regions. As a result, our reserve replacement needs from new prospects may be greater than those of other oil and gas companies. If the merger is consummated, the proportion of short-lived Gulf of Mexico properties relative to our total properties will increase substantially. Also, our revenues and return on capital will depend significantly on prices prevailing during these relatively short production periods. Our ability to slow or shut in production from producing wells during periods of low prices for oil and natural gas may be limited by reservoir characteristics or by our need to generate revenues to fund ongoing capital commitments or repay debt.

Any production problems related to our Gulf of Mexico properties could reduce our revenue, profitability and cash flow materially.

A substantial portion of our exploration and production activities are located in the Gulf of Mexico. This concentration of activity makes us more vulnerable than some other industry participants to the risks associated with the Gulf of Mexico, including delays and increased costs relating to adverse weather conditions such as hurricanes, which are common in the Gulf of Mexico during certain times of the year, drilling rig and other oilfield services and compliance with environmental and other laws and regulations.

Our exploration and development activities may not be commercially successful.

Exploration activities involve numerous risks, including the risk that no commercially productive oil or natural gas reservoirs will be discovered. In addition, the future cost and timing of drilling, completing and producing wells is often uncertain. Furthermore, drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions, including hurricanes, which are common in the Gulf of Mexico during certain times of the year;
- compliance with governmental regulations;
- unavailability or high cost of drilling rigs, equipment or labor;
- reductions in oil and natural gas prices; and
- limitations in the market for oil and natural gas.

If any of these factors were to occur with respect to a particular project, we could lose all or a part of our investment in the project, or we could fail to realize the expected benefits from the project, either of which could materially and adversely affect our revenues and profitability.

Our exploratory drilling projects are based in part on seismic data, which is costly and cannot ensure the commercial success of the project.

Our decisions to purchase, explore, develop and exploit prospects or properties depend in part on data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often uncertain. Even when used and properly interpreted, 3-D seismic data and visualization techniques only assist geoscientists and geologists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know conclusively if hydrocarbons are present or producible economically. In addition, the use of 3-D seismic and other advanced technologies require greater

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predrilling expenditures than traditional drilling strategies. Because of these factors, we could incur losses as a result of exploratory drilling expenditures. Poor results from exploration activities could have a material adverse effect on our future cash flows, ability to replace reserves and results of operations.

Oil and gas drilling and production involve many business and operating risks, any one of which could reduce our levels of production, cause substantial losses or prevent us from realizing profits.

Our business is subject to all of the operating risks associated with drilling for and producing oil and natural gas, including:

- fires;
- explosions;
- blow-outs and surface cratering;
- uncontrollable flows of underground natural gas, oil and formation water;
- natural disasters;
- pipe or cement failures;
- casing collapses;
- lost or damaged oilfield drilling and service tools;
- abnormally pressured formations; and
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases.

If any of these events occurs, we could incur substantial losses as a result of injury or loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties, suspension of our operations and repairs to resume operations.

Our offshore operations involve special risks that could increase our cost of operations and adversely affect our ability to produce oil and gas.

Offshore operations are subject to a variety of operating risks specific to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce or eliminate the funds available for exploration, development or leasehold acquisitions, or result in loss of equipment and properties. For more information on the impact of recent hurricanes on Mariner s operations and the Forest Gulf of Mexico operations, see Management s Discussion and Analysis of Financial Condition and Results of Operations Recent Developments beginning on page 56 and Management s Discussion and Analysis of Financial Condition and Results of Operations of the Forest Gulf of Mexico Operations Recent Developments beginning on page 141.

Exploration for oil or natural gas in the deepwater of the Gulf of Mexico generally involves greater operational and financial risks than exploration on the shelf. Deepwater drilling generally requires more time and more advanced drilling technologies, involving a higher risk of technological failure and usually higher drilling costs. Our deepwater wells use subsea completion techniques with subsea trees tied back to host production facilities with flow lines. The installation of these subsea trees and flow lines requires substantial time and the use of advanced remote installation mechanics. These operations may encounter mechanical difficulties and equipment failures that could result in significant cost overruns. Furthermore, the deepwater operations generally lack the physical and oilfield service infrastructure present in the

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shallow waters of the Gulf of Mexico. As a result, a significant amount of time may elapse between a deepwater discovery and our marketing of the associated oil or natural gas, increasing both the financial and operational risk involved with these operations. Because of the lack and high cost of infrastructure, some reserve discoveries in the deepwater may never be produced economically.

Our hedging transactions may not protect us adequately from fluctuations in oil and natural gas prices and may limit future potential gains from increases in commodity prices or result in losses.

We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in oil and natural gas prices and to achieve more predictable cash flow. These financial arrangements typically take the form of price swap contracts and costless collars. Hedging arrangements expose us to the risk of financial loss in some circumstances, including situations when the other party to the hedging contract defaults on its contract or production is less than expected. During periods of high commodity prices, hedging arrangements may limit significantly the extent to which we can realize financial gains from such higher prices. For example, in calendar year 2004, our hedging arrangements reduced the benefit we received from increases in the prices for oil and natural gas by approximately $27.6 million ($76.9 million on a pro forma basis, including the Forest Gulf of Mexico operations). Although we currently maintain an active hedging program, we may choose not to engage in hedging transactions in the future. As a result, we may be affected adversely during periods of declining oil and natural gas prices.

We will require additional capital to fund our future activities. If we fail to obtain additional capital, we may not be able to implement fully our business plan, which could lead to a decline in reserves.

We depend on our ability to obtain financing beyond our cash flow from operations. Historically, we have financed our business plan and operations primarily with internally generated cash flow, bank borrowings, proceeds from the sale of oil and natural gas properties, entering into exploration arrangements with other parties, the issuance of public debt, privately raised equity and, prior to the bankruptcy of Enron Corp. (our indirect parent company until March 2, 2004), borrowings from Enron affiliates. In the future, we will require substantial capital to fund our business plan and operations. We expect to be required to meet our needs from our excess cash flow, debt financings and additional equity offerings (subject to certain federal tax limitations during the two-year period following the spin-off). Sufficient capital may not be available on acceptable terms or at all. If we cannot obtain additional capital resources, we may curtail our drilling, development and other activities or be forced to sell some of our assets on unfavorable terms.

The issuance of additional debt would require that a portion of our cash flow from operations be used for the payment of interest on our debt, thereby reducing our ability to use our cash flow to fund working capital, capital expenditures, acquisitions and general corporate requirements, which could place us at a competitive disadvantage relative to other competitors. Additionally, if revenues decrease as a result of lower oil or natural gas prices, operating difficulties or declines in reserves, our ability to obtain the capital necessary to undertake or complete future exploration and development programs and to pursue other opportunities may be limited, which could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could result in a decline in our oil and natural gas reserves.

Properties we acquire (including the Forest Gulf of Mexico properties) may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities.

Properties we acquire, including the Forest Gulf of Mexico properties, may not produce as expected, may be in an unexpected condition and may subject us to increased costs and liabilities, including environmental liabilities. The reviews we conduct of acquired properties prior to acquisition are not capable of identifying all potential adverse conditions. Generally, it is not feasible to review in depth every individual property involved in each acquisition. Ordinarily, we will focus our review efforts on the higher

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value properties or properties with known adverse conditions and will sample the remainder. However, even a detailed review of records and properties may not necessarily reveal existing or potential problems or permit a buyer to become sufficiently familiar with the properties to assess fully their condition, any deficiencies, and development potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken.

Market conditions or transportation impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions, the unavailability of satisfactory oil and natural gas transportation or the remote location of our drilling operations may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines or trucking and terminal facilities. In deepwater operations, the availability of a ready market depends on the proximity of and our ability to tie into existing production platforms owned or operated by others and the ability to negotiate commercially satisfactory arrangements with the owners or operators. We may be required to shut in wells or delay initial production for lack of a market or because of inadequacy or unavailability of pipeline or gathering system capacity. When that occurs, we are unable to realize revenue from those wells until the production can be tied to a gathering system. This can result in considerable delays from the initial discovery of a reservoir to the actual production of the oil and natural gas and realization of revenues.

The unavailability or high cost of drilling rigs, equipment, supplies or personnel could affect adversely our ability to execute on a timely basis our exploration and development plans within budget, which could have a material adverse effect on our financial condition and results of operations.

Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or affect adversely our exploration and development operations, which could have a material adverse effect on our financial condition and results of operations. An increase in drilling activity in the U.S. or the Gulf of Mexico could increase the cost and decrease the availability of necessary drilling rigs, equipment, supplies and personnel.

Competition in the oil and natural gas industry is intense, and many of our competitors have resources that are greater than ours giving them an advantage in evaluating and obtaining properties and prospects.

We operate in a highly competitive environment for acquiring prospects and productive properties, marketing oil and natural gas and securing equipment and trained personnel. Many of our competitors are major and large independent oil and natural gas companies, and possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to develop and acquire more prospects and productive properties than our financial or personnel resources permit. Our ability to acquire additional prospects and discover reserves in the future will depend on our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Larger competitors may be better able to withstand sustained periods of unsuccessful drilling and absorb the burden of changes in laws and regulations more easily than we can, which would adversely affect our competitive position. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

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Financial difficulties encountered by our farm-out partners or third-party operators could affect the exploration and development of our prospects adversely.

From time to time, we enter into farm-out agreements to fund a portion of the exploration and development costs of our prospects. Moreover, other companies operate some of the other properties in which we have an ownership interest. Liquidity and cash flow problems encountered by our partners and co-owners of our properties may lead to a delay in the pace of drilling or project development that may be detrimental to a project.

In addition, our farm-out partners and working interest owners may be unwilling or unable to pay their share of the costs of projects as they become due. In the case of a farm-out partner, we may have to obtain alternative funding in order to complete the exploration and development of the prospects subject to the farm-out agreement. In the case of a working interest owner, we may be required to pay the working interest owner s share of the project costs. We cannot assure you that we would be able to obtain the capital necessary in order to fund either of these contingencies.

We cannot control the drilling and development activities on properties we do not operate, and therefore we may not be in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves.

Other companies operate some of the properties in which we have an interest. As a result, we have a limited ability to exercise influence over operations for these properties or their associated costs. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence operations and associated costs could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities. The success and timing of drilling and development activities on properties operated by others therefore depend upon a number of factors that are outside of our control, including timing and amount of capital expenditures, the operator s expertise and financial resources, approval of other participants in drilling wells and selection of technology.

Compliance with environmental and other government regulations could be costly and could affect production negatively.

Exploration for and development, production and sale of oil and natural gas in the U.S. and the Gulf of Mexico are subject to extensive federal, state and local laws and regulations, including environmental and health and safety laws and regulations. We may be required to make large expenditures to comply with these environmental and other requirements. Matters subject to regulation include, among others, environmental assessment prior to development, discharge and emission permits for drilling and production operations, drilling bonds, and reports concerning operations and taxation.

Under these laws and regulations, and also common law causes of action, we could be liable for personal injuries, property damage, oil spills, discharge of pollutants and hazardous materials, remediation and clean-up costs and other environmental damages. Failure to comply with these laws and regulations or to obtain or comply with required permits may result in the suspension or termination of our operations and subject us to remedial obligations as well as administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that substantially increase our costs. We cannot predict how agencies or courts will interpret existing laws and regulations, whether additional or more stringent laws and regulations will be adopted or the effect these interpretations and adoptions may have on our business or financial condition. For example, the Oil Pollution Act of 1990 (the OPA) imposes a variety of regulations on responsible parties related to the prevention of oil spills. The implementation of new, or the modification of existing, environmental laws or regulations promulgated pursuant to the OPA could have a material adverse impact on us. Further, Congress or the MMS could decide to limit exploratory drilling or natural gas production in additional areas of the Gulf of Mexico. Accordingly, any of these liabilities, penalties, suspensions, terminations or regulatory changes could have a material adverse effect on our financial condition and results of operations. See Business Regulation for more information on our regulatory and environmental matters.

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Our insurance may not protect us against our business and operating risks.

We maintain insurance for some, but not all, of the potential risks and liabilities associated with our business. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. As a result, we may not be able to renew our existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all.

Although we maintain insurance at levels we believe are appropriate and consistent with industry practice, we are not fully insured against all risks, including drilling and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Losses and liabilities from uninsured and underinsured events and delay in the payment of insurance proceeds could have a material adverse effect on our financial condition and results of operations. The impact of Hurricanes Katrina and Rita have resulted in escalating insurance costs and less favorable coverage terms. See Business Insurance Matters and The Forest Gulf of Mexico Operations Insurance Matters for more information.

Risks Related to our Business if the Merger is not Consummated

If the merger is not ultimately consummated, the market value of our common stock could decline, and our ability to consummate alternate acquisition transactions could be reduced.

If the proposed merger with Forest Energy Resources is not ultimately consummated, whether because our stockholders do not adopt the merger agreement at the annual meeting or because some other condition to closing is not satisfied, the market value of our common stock could be reduced. Our stock price could be adversely affected for other reasons related to the failure to close, including due to our reduced opportunities to consummate alternate transactions, or simply because the market had perceived the failed transaction as accretive to our stockholders. In addition, we may not meet the listing requirements for listing on the New York Stock Exchange if the proposed merger is not consummated, which would disqualify us from listing our common stock on that exchange.

In addition, if the merger is not consummated our ability to enter into other merger or acquisition transactions could be hindered. Under the terms of the merger agreement, if the agreement is terminated in certain circumstances where an alternate proposal to acquire us is outstanding, we could be required to pay Forest a termination fee and expense reimbursement upon the consummation of an alternate transaction. The termination fee and expense reimbursement provisions would therefore have the effect of making it more costly to acquire us, reducing the likelihood that such an acquisition would occur. Moreover, potential acquisition partners could be deterred from pursuing transactions with us, because they may speculate that the failure was caused by due diligence problems or other issues that motivated Forest not to close the transaction.

If the merger is not consummated, a significant part of the value of our production and reserves will be concentrated in a small number of offshore properties. As a result, any production problems or inaccuracies in reserve estimates related to those properties could reduce our revenue, profitability and cash flow materially.

During December 2005, approximately 69% of our daily production came from 19 offshore fields. If mechanical problems, storms or other events curtail a substantial portion of this production in the future, our cash flow would be affected adversely. At December 31, 2004, approximately 37% of our proved reserves were located on seven offshore properties. If the actual reserves associated with any one of these properties are less than our estimated reserves, our results of operations and financial condition could be adversely affected. During the three years ended December 31, 2002, 2003 and 2004, weather and mechanical problems affecting our offshore producing properties resulted in aggregate downtime for our offshore producing properties of 7.3%, 7.1% and 7.3%, respectively.

If the merger is not consummated, the smaller size of our operations relative to those of the combined operations could reduce our ability to participate in projects or pursue acquisition opportunities that would increase our profitability.

The proposed merger with Forest Energy Resources would approximately triple the pro forma daily net production of Mariner on a stand-alone basis. If the merger is not consummated, the scale of our operations would be significantly smaller than that of the combined operations. The smaller operational scale could adversely impact our ability, relative to our ability if the merger were consummated, to participate in larger scale exploratory and development drilling projects or to pursue acquisition opportunities. The inability to participate in such transactions could reduce our profitability and adversely affect our results of operations.

Risks Related to the Spin-Off and the Merger

The consummation of the merger is subject to numerous conditions, many of which are beyond our control.

The merger will be completed only if certain conditions, including the following, are satisfied (or waived in certain cases):

- the adoption of the merger agreement by Mariner stockholders holding a majority of the Mariner common stock and the approval of the proposed amendment to Mariner s certificate of incorporation;
- the absence of legal restrictions that would prevent the completion of the transactions;
- the receipt by Forest, Mariner and Forest Energy Resources of an opinion from their respective counsel to the effect that the merger will be treated as a reorganization for federal income tax purposes;
- the completion of the spin-off in accordance with the distribution agreement;
- the receipt of material consents, approvals and authorizations of governmental authorities;
- the expiration or termination of any applicable waiting period under the Hart-Scott-Rodino Act;
- the SEC declaring effective the registration statements of Mariner relating to the shares of Mariner common stock to be issued in the merger and those shares held by its existing stockholders;
- the representations and warranties contained in the merger agreement being materially true and correct, the performance in all material respects by the parties of their covenants and other agreements in the merger agreement;
- the approval for listing on the New York Stock Exchange or Nasdaq of Mariner s common stock; and
- Mariner and Forest receiving the consents required pursuant to their credit facilities (with Mariner or Forest Energy Resources having entered into a new or amended credit facility sufficient to operate the combined businesses), and Forest receiving any consents required from its bondholders.

We cannot assure you that the conditions to the consummation of the merger will be satisfied or waived, or that the closing will occur. Some of the conditions, such as the adoption of the merger

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agreement by our stockholders, the absence of legal restrictions and the receipt of required consents are partially or completely beyond our control.

The market value of our common stock could decline if large amounts of our common stock are sold following the spin-off and merger.

The market price of our common stock could decline as a result of sales of a large number of shares in the market after the completion of the spin-off and merger or the perception that these sales could occur. Immediately after the merger, Forest shareholders will hold, in the aggregate, approximately 58% of our common stock on a pro forma basis. Currently, Forest shareholders include index funds tied to various stock indices, and institutional investors subject to various investing guidelines. Because we may not be included in these indices at the time of the merger or may not meet the investing guidelines of some of these institutional investors, these index funds and institutional investors may decide to sell the Mariner common stock they receive in the merger. These sales may negatively affect the price of our common stock and also may make it more difficult for us to obtain additional capital by selling equity securities in the future at a time and at a price that we deem appropriate.

Historically, Forest has operated with properties in diverse geographic locations, including the Gulf Coast, the Western United States, Alaska, Canada and other international locations. In contrast, following the spin-off and merger, Mariner will operate as a stand-alone oil and gas exploration, development and production company with operations primarily in the Gulf of Mexico and in West Texas. Shareholders of Forest who chose to invest in a geographically diverse company may not wish to continue to invest in one that is less geographically diverse, such as Mariner. As a result, such shareholders may seek to sell the shares of our common stock received in the merger.

The integration of the Forest Gulf of Mexico operations following the merger will be difficult, and will divert our management s attention away from our normal operations.

There is a significant degree of difficulty and management involvement inherent in the process of integrating the Forest Gulf of Mexico operations. These difficulties include:

- the challenge of integrating the Forest Gulf of Mexico operations while carrying on the ongoing operations of our business;
- the challenge of managing a significantly larger company, with more than twice the PV10 of Mariner on a stand-alone basis;
- faulty assumptions underlying our expectations;
- the difficulty associated with coordinating geographically separate organizations;
- the challenge of integrating the business cultures of the two companies;
- attracting and retaining personnel associated with the Forest Gulf of Mexico operations following the merger; and
- the challenge and cost of integrating the information technology systems of the two companies.

The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer.

If we fail to realize the anticipated benefits of the merger, stockholders may receive lower returns than they expect.

The success of the merger will depend, in part, on our ability to realize the anticipated growth opportunities from combining the Forest Gulf of Mexico operations with Mariner. Even if we are able to successfully combine the two businesses, it may not be possible to realize the full benefits of the proved reserves, enhanced growth of production volume, cost savings from operating synergies and other benefits that we currently expect to result from the merger, or realize these benefits within the time frame that is currently expected. The benefits of the merger may be offset by operating losses relating to changes in commodity prices, or in oil and gas industry conditions, or by risks and uncertainties relating to the combined company s exploratory prospects, or an increase in operating or other costs or other difficulties. If we fail to realize the benefits we anticipate from the merger, stockholders may receive lower returns on our stock than they expect.

We expect to incur significant charges relating to the integration plan that could materially and adversely affect our period-to-period results of operations following the merger.

We are developing a plan to integrate the Forest Gulf of Mexico operations with our operations after the merger. Following the merger, we anticipate that from time to time we will incur charges to our earnings in connection with the integration. These charges will include expenses incurred in connection with relocating and retaining employees and increased professional and consulting costs. We also expect to incur significant expenses related to being a public company. We will not be able to quantify the exact amount of these charges or the period(s) in which they will be incurred until after the merger is completed. Some factors affecting the cost of the integration include the timing of the closing of the merger, the training of new employees, the amount of severance and other employee-related payments resulting from the merger, and the limited length of time during which transitional services are provided by Forest.

The number of shares Forest shareholders will receive in the merger is not subject to adjustment based on the value of the Mariner or the Forest Gulf of Mexico operations. Accordingly, because this value may fluctuate, the market value of the Mariner common stock that Forest shareholders receive in the merger may not reflect the value of the individual companies at the time of the merger.

Following the spin-off and the merger, the holders of Forest common stock will ultimately become entitled to receive approximately 0.8 shares of Mariner common stock for each Forest share they own. This ratio will not be adjusted for changes in the value of our company or the Forest Gulf of Mexico operations. If our value relative to the Forest Gulf of Mexico operations increases (or the value of the Forest Gulf of Mexico operations decreases relative to our value) prior to the completion of the merger, the market value of the Mariner common stock that Forest shareholders receive in the merger may not reflect the then-current relative values of the individual companies.

Regulatory agencies may delay or impose conditions on approval of the spin-off and the merger, which may diminish the anticipated benefits of the merger.

Completion of the spin-off and merger is conditioned upon the receipt of required governmental consents, approvals, orders and authorizations. While we intend to pursue vigorously all required governmental approvals and do not know of any reason why we would not be able to obtain the necessary approvals in a timely manner, the requirement to receive these approvals before the spin-off and merger could delay the completion of the spin-off and merger, possibly for a significant period of time after Mariner stockholders have approved the merger proposal at the annual meeting. In addition, these governmental agencies may attempt to condition their approval of the merger on the imposition of conditions that could have a material adverse effect on our operating results or the value of our common stock after the spin-off and merger are completed.

Any delay in the completion of the spin-off and merger could diminish anticipated benefits of the spin-off and merger or result in additional transaction costs, loss of revenue or other effects associated with uncertainty about the transaction. Any uncertainty over the ability of the companies to complete the spin-off and merger could make it more difficult for us to retain key employees or to pursue business strategies. In addition, until the spin-off and merger are completed, the attention of our management may be diverted from ongoing business concerns and regular business responsibilities to the extent management is focused on matters relating to the transaction, such as obtaining regulatory approvals.

In order to preserve the tax-free treatment of the spin-off, we will be required to abide by potentially significant restrictions which could limit our ability to undertake certain corporate actions (such as the issuance of our common shares or the undertaking of a change in control) that otherwise could be advantageous.

The tax sharing agreement imposes ongoing restrictions on Forest and on us to ensure that applicable statutory requirements under the Internal Revenue Code and applicable Treasury regulations continue to be met so that the spin-off remains tax-free to Forest and its shareholders. As a result of these restrictions, our ability to engage in certain transactions, such as the redemption of our common stock, the issuance of equity securities and the utilization of our stock as currency in an acquisition, will be limited for a period of two years following the spin-off.

If Forest or Mariner takes or permits an action to be taken (or omits to take an action) that causes the spin-off to become taxable, the relevant entity generally will be required to bear the cost of the resulting tax liability to the extent that the liability results from the actions or omissions of that entity. If the spin-off became taxable, Forest would be expected to recognize a substantial amount of income, which would result in a material amount of taxes. Any such taxes allocated to us would be expected to be material to us, and could cause our business, financial condition and operating results to suffer. These restrictions may reduce our ability to engage in certain business transactions that otherwise might be advantageous to us and our stockholders and could have a negative impact on our business and stockholder value.

Some of our directors and executive officers have interests that are different from, or in addition to, the interests of our stockholders.

When considering the recommendations of our board of directors, you should be aware that some of our directors and executive officers have interests and arrangements that may be different from your interests as stockholders, including:

- arrangements regarding the appointment of directors and officers of Mariner following the merger; and

- arrangements whereby our executive officers will receive a cash payment of $1,000 each in exchange for the waiver of certain rights under their employment agreements, including the automatic vesting or acceleration of restricted stock and options upon the completion of the merger and the right to receive a lump sum cash payment if the officer voluntarily terminates employment without good reason within nine months following the completion of the merger.

Risks Related to our Common Stock

An active market for our common stock may not develop and the market price for shares of our common stock may be highly volatile and could be subject to wide fluctuations after this offering.

We are a private company, and there is no public market for our common stock. An active market for our common stock may not develop or may not be sustained after this offering. In addition, we cannot assure you as to the liquidity of any such market that may develop or the price that our stockholders may obtain for their shares of our common stock.

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Even if an active trading market develops, the market price for shares of our common stock may be highly volatile and could be subject to wide fluctuations. Some of the factors that could negatively affect our share price include:

- actual or anticipated downward revisions in our reserve estimates;
- our operating results being less than anticipated;
- reductions in oil and gas prices;
- publication of unfavorable research reports about us or the exploration and production industry;
- increases in market interest rates which may increase our cost of capital;
- the enactment of more stringent laws or regulations applicable to our business, or unfavorable court rulings or enforcement or legal actions;
- increases in royalties or taxes payable in the operation of our business;
- a general decline in market valuations of similar companies;
- adverse market reaction to any increased indebtedness we incur in the future;
- departures of key management personnel;
- increases to our asset retirement obligations;
- adverse actions taken by our stockholders;
- negative speculation in the press or investment community; and
- adverse general market and economic conditions.

We do not anticipate paying any dividends on our common stock in the foreseeable future.

We do not expect to declare or pay any cash or other dividends in the foreseeable future on our common stock. Our existing revolving credit facility restricts our ability to pay cash dividends on our common stock, and we may also enter into other credit agreements or other borrowing arrangements in the future that restrict our ability to declare or pay cash dividends on our common stock.

Mariner stockholders will experience substantial and immediate dilution as a result of the merger, and may experience dilution of their ownership interests due to the future issuance of additional shares of our common stock, which could have an adverse effect on our stock price.

If the merger is completed, the current owners of Mariner s common stock will experience substantial and immediate dilution from the issuance of shares of Mariner common stock to Forest shareholders, such that the Mariner stockholders will own approximately 42% of the Mariner common stock following the merger. Additionally, we may in the future issue our previously authorized and unissued securities, resulting in the dilution of the ownership interests of our present stockholders. We are currently authorized to issue 70 million shares of common stock and 20 million shares of preferred stock with such designations, preferences and rights as determined by our board of directors. As a result of the proposed amendment to our certificate of incorporation, our authorized shares would be increased to 180 million shares of common stock and 20 million shares of preferred stock. Pursuant to the proposed addition of shares to our stock incentive plan, the maximum number of shares issuable under the plan would, if the proposal is approved, be increased to 6.5 million shares.

The potential issuance of such additional shares of common stock may create downward pressure on the trading price of our common stock. We may also issue additional shares of our common stock or other securities that are convertible into or exercisable for common stock (subject to certain federal tax limitations during the two-year period following the spin-off) in connection with the hiring of personnel, future acquisitions, future public offerings or private placements of our securities for capital raising purposes, or for other business purposes. Future sales of substantial amounts of our common stock, or the perception that sales could occur, could have a material adverse effect on the price of our common stock.

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Provisions in our organizational documents and under Delaware law could delay or prevent a change in control of our company, which could adversely affect the price of our common stock.

The existence of some provisions in our organizational documents and under Delaware law could delay or prevent a change in control of our company, which could adversely affect the price of our common stock. The provisions in our certificate of incorporation and bylaws that could delay or prevent an unsolicited change in control of our company include a staggered board of directors, board authority to issue preferred stock, and advance notice provisions for director nominations or business to be considered at a stockholder meeting. In addition, Delaware law imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. See Description of Capital Stock.

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CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

Various statements in this prospectus, including those that express a belief, expectation, or intention, as well as those that are not statements of historical fact, are forward-looking statements. The forward-looking statements may include projections and estimates concerning the timing and success of specific projects and our future production, revenues, income and capital spending. Our forward-looking statements are generally accompanied by words such as estimate, project, predict, believe, expect, anticipate, potential, plan, goal or other words that convey future events or outcomes. The forward-looking statements in this prospectus speak only as of the date of this prospectus; we disclaim any obligation to update these statements unless required by securities law, and we caution you not to rely on them unduly. We have based these forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. We disclose important factors that could cause our actual results to differ materially from our expectations under Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations of the Forest Gulf of Mexico Operations, Management s Discussion and Analysis of Financial Condition and Results of Operations and elsewhere in this prospectus. These risks, contingencies and uncertainties relate to, among other matters, the following:

- the volatility of oil and natural gas prices;
- discovery, estimation, development and replacement of oil and natural gas reserves;
- cash flow, liquidity and financial position;
- business strategy;
- amount, nature and timing of capital expenditures, including future development costs;
- availability and terms of capital;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment;
- operating costs and other expenses;
- prospect development and property acquisitions;
- marketing of oil and natural gas;
- competition in the oil and natural gas industry;
- the impact of weather and the occurrence of natural disasters such as fires, floods and other catastrophic events and natural disasters;
- governmental regulation of the oil and natural gas industry;
- developments in oil-producing and natural gas-producing countries;

the proposed merger, including strategic plans, expectations and objectives for future operations, the completion of those transactions, and the realization of expected benefits from the transactions; and

disruption from the merger making it more difficult to manage Mariner s business.

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USE OF PROCEEDS

We will not receive any of the proceeds from the sale of the shares of common stock offered by this prospectus. Any proceeds from the sale of the shares offered by this prospectus will be received by the selling stockholders.

CAPITALIZATION

The following table shows our capitalization as of September 30, 2005. You should refer to Selected Historical Consolidated Financial Data, Management s Discussion and Analysis of Financial Condition and Results of Operations and the financial statements included elsewhere in this prospectus in evaluating the material presented below.

		September 30, 2005
		(in millions)
Long-term debt:		
Credit facility revolving note due March 2007	$	75.0
Promissory note to former indirect stockholder(1)		4.0
Total long-term debt		79.0
Stockholders equity(2)		178.6
Total capitalization	$	257.6

(1) For a description of the promissory note to our former indirect stockholder, see Management s Discussion and Analysis of Financial Condition and Results of Operations JEDI Term Promissory Note.

(2) Reflects the receipt of net proceeds from the sale of 3.6 million shares reduced by approximately $1.9 million of offering costs.

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DILUTION

Our net tangible book value as of September 30, 2005 was $5.01 per share of common stock. Net tangible book value per share is determined by dividing our tangible net worth (tangible assets less total liabilities) by the 35,615,400 shares of our common stock that were outstanding on September 30, 2005. Investors who purchase our common stock in this offering may pay a price per share that exceeds the net tangible book value per share of our common stock. If you purchase our common stock from the selling stockholders identified in this prospectus, you will experience immediate dilution of $14.99 in the net tangible book value per share of our common stock assuming a sale price of $20.00 per share, representing the September 30, 2005 price at which the shares traded in the PORTAL Market®. The following table illustrates the per share dilution to new investors purchasing shares from the selling stockholders identified in this prospectus:

Assumed offering price per share		$ 20.00
Net tangible book value per share at September 30, 2005	$ 5.01	
Increase per share attributable to new investors	-0-	
Net tangible book value per share after this offering		5.01
Dilution per share to new investors		$ 14.99

The foregoing discussion and table are based upon the number of shares actually issued and outstanding as of September 30, 2005. As of September 30, 2005, we had 809,000 stock options outstanding at an average exercise price of approximately $14.00 per share, none of which were vested as of September 30, 2005. To the extent the market value of our shares is greater than $14.00 per share and any of these outstanding options are exercised, there may be further dilution to new investors.

DIVIDEND POLICY

We do not expect to pay dividends in the near future. Our credit facility contains restrictions on the payment of dividends to stockholders. See Management s Discussion and Analysis of Financial Condition and Results of Operations Credit Facility.

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SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

The following table shows Mariner s historical consolidated financial data as of and for each of the four years ended December 31, 2003, the period from January 1, 2004 through March 2, 2004, the period from March 3, 2004 through December 31, 2004, the period from March 3, 2004 through September 30, 2004 and the nine-month period ended September 30, 2005. The historical consolidated financial data as of and for the four years ended December 31, 2003, the period from January 1, 2004 through March 2, 2004 and the period from March 3, 2004 through December 31, 2004 are derived from Mariner s audited financial statements included herein, and the historical consolidated financial data for the period from March 3, 2004 through September 30, 2004 and the nine-month period ended September 30, 2005 are derived from unaudited financial statements of Mariner. You should read the following data in connection with Management s Discussion and Analysis of Financial Condition and Results of Operations and the consolidated financial statements included elsewhere in this prospectus, where there is additional disclosure regarding the information in the following table, including pro forma information regarding the merger. Mariner s historical results are not necessarily indicative of results to be expected in future periods.

On March 2, 2004, Mariner s former indirect parent, Mariner Energy LLC, merged with MEI Acquisitions, LLC, an affiliate of the private equity funds, Carlyle/ Riverstone Global Energy and Power Fund II, L.P. and ACON Investments LLC. The financial information contained herein is presented in the style of Pre-2004 Merger activity (for all periods prior to March 2, 2004) and Post-2004 Merger activity (for the March 3, 2004 through December 31, 2004 period and the March 3, 2004 through September 30, 2004 period) to reflect the impact of the restatement of assets and liabilities to fair value as required by push-down purchase accounting at the March 2, 2004 merger date.

	Post-2004 Merger			**Pre-2004 Merger**				
	Nine Months Ended September 30, 2005	**Period from March 3, 2004 through September 30, 2004**	**Period from March 3, 2004 through December 31, 2004**	**Period from January 1, 2004 through March 2, 2004**	**Year Ended December 31, 2003**	**2002**	**2001**	**2000**
	(in millions, except per share data)							
Statement of Operations Data:								
Total revenues(1)	$ 151.2	$ 122.5	$ 174.4	$ 39.8	$ 142.5	$ 158.2	$ 155.0	$ 121.1
Lease operating expenses	20.2	15.1	21.4	4.1	24.7	26.1	20.1	17.2
Transportation expenses	1.7	3.7	1.9	1.1	6.3	10.5	12.0	7.8
Depreciation, depletion and amortization	43.4	37.4	54.3	10.6	48.3	70.8	63.5	56.8
Impairment of production equipment held for use	0.5	1.0	1.0					
					3.2			

Derivative settlement								
Impairment of Enron related receivables						3.2	29.5	
General and administrative expenses	26.7	6.2	7.6	1.1	8.1	7.7	9.3	6.5
Operating income	58.7	59.1	88.2	22.9	51.9	39.9	20.6	32.8
Interest income	0.7	0.2	0.2	0.1	0.8	0.4	0.7	0.1
Interest expense	(5.4)	(4.4)	(6.0)		(7.0)	(10.3)	(8.9)	(11.0)
Income before income taxes	54.0	54.9	82.4	23.0	45.7	30.0	12.4	21.9
Provision for income taxes	(18.4)	(19.2)	(28.8)	(8.1)	(9.4)			
Income before cumulative effect of change in accounting method net of tax effects	35.6	35.7	53.6	14.9	36.3	30.0	12.4	21.9
Income before cumulative effect per common share								
Basic	1.10	1.20	1.80	.50	1.22	1.01	.42	.74
Diluted	1.07	1.20	1.80	.50	1.22	1.01	.42	.74
Cumulative effect of changes in accounting method					1.9			
Net income	$ 35.6	$ 35.7	$ 53.6	$ 14.9	$ 38.2	$ 30.0	$ 12.4	$ 21.9
Net income per common share								
Basic	1.10	1.20	1.80	.50	1.29	1.01	.42	.74
Diluted	1.07	1.20	1.80	.50	1.29	1.01	.42	.74
Capital Expenditure and Disposal Data:								
Exploration, including leasehold/seismic	$ 23.6	$ 35.7	$ 40.4	$ 7.5	$ 31.6	$ 40.4	$ 66.3	$ 46.7
Development and other	106.8	50.2	93.2	7.8	51.7	65.7	98.2	61.4
Proceeds from property conveyances					(121.6)	(52.3)	(90.5)	(29.0)
Total capital expenditures net of	$ 130.4	$ 85.9	$ 133.6	$ 15.3	$ (38.3)	$ 53.8	$ 74.0	$ 79.1

proceeds from
property
conveyances

(1) Includes effects of hedging.

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	Post-2004 Merger		Pre-2004 Merger			
			December 31,			
	September 30, 2005	December 31, 2004	2003	2002	2001	2000
	(in millions)					
Balance Sheet Data:(1)						
Property and equipment, net, full cost method	$ 393.3	$ 303.8	$ 207.9	$ 287.6	$ 290.6	$ 287.8
Total assets	502.2	376.0	312.1	360.2	363.9	335.4
Long-term debt, less current maturities	79.0	115.0		99.8	99.8	129.7
Stockholder s equity	178.6	133.9	218.2	170.1	180.1	141.9
Working capital (deficit)(2)	(30.2)	(18.7)	38.3	(24.4)	(19.6)	(15.4)

(1) Balance sheet data as of December 31, 2004 reflects purchase accounting adjustments to oil and gas properties, total assets and stockholder s equity resulting from the acquisition of our former indirect parent on March 2, 2004.

(2) Working capital (deficit) excludes current derivative assets and liabilities, deferred tax assets and restricted cash.

	Post-2004 Merger			Pre-2004 Merger				
	Nine Months Ended September 30, 2005	Period from March 3, 2004 through September 30, 2004	Period from March 3, 2004 through December 31, 2004	Period from January 1, 2004 through March 2, 2004	Year Ended December 31, 2003	2002	2001	2000
	(in millions)							
Other Financial Data:								
EBITDA(1)	$ 102.7	$ 97.5	$ 143.5	$ 33.4	$ 100.3	$ 113.9	$ 113.6	$ 89.6
Net cash provided by operating activities	135.4	96.8	135.9	20.3	103.5	60.3	113.5	63.9
Net cash (used) provided by investing activities	(142.1)	(85.9)	(133.6)	(15.3)	38.3	(53.8)	(74.0)	(79.1)
Net cash (used) provided by financing activities	8.7	(74.9)	64.9		(100.0)		(30.0)	17.4
Reconciliation of Non-GAAP Measures:								
EBITDA(1)	$ 102.7	$ 97.5	$ 143.5	$ 33.4	$ 100.3	$ 113.9	$ 113.6	$ 89.6

Changes in working capital	25.1	9.7	6.9	(13.2)	21.8	(20.4)	7.5	(15.5)
Non-cash hedge gain(2)	(3.6)	(5.1)	(7.9)		(2.0)	(23.2)		
Amortization/other	0.9	0.5	0.8			(0.1)	0.6	0.7
Stock compensation expense	17.6							
Net interest expense	(4.7)	(4.2)	(5.8)	0.1	(6.2)	(9.9)	(8.2)	(10.9)
Income tax expense	(2.6)	(1.6)	(1.6)		(10.4)			
Net cash provided by operating activities	$ 135.4	$ 96.8	$ 135.9	$ 20.3	$ 103.5	$ 60.3	$ 113.5	$ 63.9

(1) EBITDA means earnings before interest, income taxes, depreciation, depletion and amortization. For the nine months ended September 30, 2005, EBITDA includes $17.6 million in non-cash stock compensation expense related to restricted stock and stock options granted in 2005. We believe that EBITDA is a widely accepted financial indicator that provides additional information about our ability to meet our future requirements for debt service, capital expenditures and working capital, but EBITDA should not be considered in isolation or as a substitute for net income, operating income, net cash provided by operating activities or any other measure of financial performance presented in

accordance with generally accepted accounting principles or as a measure of a company s profitability or liquidity.

(2) In accordance with SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities, as amended by SFAS No. 137 and No. 138, we de-designated our contracts effective December 2, 2001 after the counterparty (an affiliate of Enron Corp.) filed for bankruptcy and recognized all market value changes subsequent to such de-designation in our earnings. The value recorded up to the time of de-designation and included in Accumulated Other Comprehensive Income (AOCI), has reversed out of AOCI and into earnings as the original corresponding production, as hedged by the contracts, is produced. We have designated subsequent hedge contracts as cash flow hedges with gains and losses resulting from the transactions recorded at market value in AOCI, as appropriate, until recognized as operating income in our Statement of Operations as the physical production hedged by the contracts is delivered.

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UNAUDITED PRO FORMA COMBINED CONDENSED FINANCIAL INFORMATION

The following unaudited pro forma combined financial information and explanatory notes present how the combined financial statements of Mariner and the Forest Gulf of Mexico operations may have appeared had the businesses actually been combined as of September 30, 2005 (with respect to the balance sheet information using currently available fair value information) or as of January 1, 2004 (with respect to statements of operations information). The unaudited pro forma combined financial information shows the impact of the merger on the historical financial position and results of operations under the purchase method of accounting with Mariner treated as the acquirer. Under this method of accounting, the assets and liabilities of the Forest Gulf of Mexico operations are recorded by Mariner at their estimated fair values as of the date the merger is completed.

The unaudited pro forma combined balance sheet as of September 30, 2005 assumes the merger was completed on that date. The unaudited pro forma combined statements of operations gives effect to the merger as if it had been completed on January 1, 2004. The merger agreement was executed on September 9, 2005 and provides for Mariner to issue approximately 50.6 million shares of common stock as consideration to Forest Energy Resources common stockholders.

The unaudited pro forma combined financial information has been derived from and should be read together with the historical consolidated financial statements of Mariner and the statements of revenues and direct operating expenses of the Forest Gulf of Mexico operations, which are included herein. The statements of revenues and direct operating expenses of the Forest Gulf of Mexico operations do not include all of the costs of doing business.

The unaudited pro forma combined condensed financial information is for illustrative purposes only. The financial results may have been different had the Forest Gulf of Mexico operations been an independent company and had the companies always been combined. You should not rely on the unaudited pro forma combined condensed financial information as being indicative of the historical results that would have been achieved had the merger occurred in the past or the future financial results that Mariner will achieve after the merger.

In addition, the purchase price allocation is preliminary and will be finalized following the closing of the merger. The final purchase price allocation will be determined after closing based on the actual fair value of current assets, current liabilities, indebtedness, long-term liabilities, proven and unproven oil and gas properties, identifiable intangible assets and the final number of shares of Mariner common stock issued in the merger and for unvested stock options that are outstanding at closing. We are continuing to evaluate all of these items; accordingly, the final purchase price may differ in material respects from that presented in the unaudited pro forma combined condensed balance sheet.

The combination of the Forest Gulf of Mexico operations with Mariner s is expected to cause the average reserve life of Mariner s oil and gas properties to decrease from current levels and to result in a higher rate of depreciation, depletion, and amortization for the combined operations. For example, the estimated proved reserves of the Forest Gulf of Mexico properties as of June 30, 2005 were 328 Bcfe and production for the six months ended June 30, 2005 (prior to hurricane related disruptions) was approximately 40.8 Bcfe, a reserve life on an annualized basis of 4.0. This ratio is indicative of the relatively higher productive rates of offshore oil and gas properties when compared to most onshore fields. While the higher productive rates generally result in a faster return on investment than onshore fields, they also result in a faster depletion of the underlying proved reserves and a resulting higher rate of depreciation, depletion, and amortization. As of June 30, 2005, Mariner s proved reserves totaled 328 Bcfe and production for the six months ended June 30, 2005 (prior to hurricane disruptions) was approximately 16.5 Bcfe, a reserve life on an annualized basis of 9.9. For the combined operations, as of June 30, 2005, proved reserves would have totaled approximately 599 Bcfe and production for the six months ended June 30, 2005 would have totaled 57.3 Bcfe, a reserve life on an annualized basis of 5.7. Mariner will also write-up the Forest Gulf of Mexico operations to estimated fair value as of the merger date, which is also expected to cause the underlying DD&A rate to increase for the combined operations.

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In connection with the merger, Mariner and Mariner Energy Resources expect to enter into a $500 million senior secured revolving credit facility, and Mariner also expects to obtain a $40 million senior secured letter of credit facility. The initial borrowing base of the revolving credit facility will be $400 million. The revolving credit facility will mature on the fourth anniversary of the closing and may be used for general corporate purposes. The letter of credit facility will mature on the third anniversary of the closing.

In connection with the spin-off and the payment of the cash amount by Forest Energy Resources to Forest pursuant to the distribution agreement, Forest Energy Resources intends to enter into a new senior term loan facility with Union Bank of California, or UBOC, as lender, in an amount equal to the lesser of the cash amount, plus the amount of the arrangement and upfront fees and expenses associated with the facility, and $200 million, plus the amount of the arrangement and upfront fees and expenses associated with the facility. At Forest Energy Resources election, interest will be determined by reference to (1) the UBOC Reference Rate or (2) the London interbank offered rate, or LIBOR, plus 1.50% per annum. In the event that any portion of the facility is outstanding after 30 days, the interest rate will increase, at Forest Energy Resources election, to (1) the UBOC Reference Rate, plus 5% per annum or (2) LIBOR plus 6.50% per annum. Interest will be payable at the applicable maturity date for LIBOR-loans and quarterly for UBOC Reference Rate loans.

The Forest Energy Resources facility is expected to be repaid with borrowings under Mariner s and Mariner Energy Resources $500 million revolving credit facility. The facility will mature 90 days from closing of the spin-off and merger and the principal will be due at maturity. Prepayments will be permitted at any time without premium or penalty (except for breakage and related costs associated with prepayments of Eurodollar loans), subject to minimum amount requirements. The facility will be unsecured with a negative pledge on Forest Energy Resources existing oil and gas properties and all other assets of Forest Energy Resources.

The facility will contain various covenants that limit Forest Energy Resources ability to do the following, among other things, except as contemplated by the distribution agreement and the merger agreement:

- incur indebtedness;
- grant certain liens;
- merge or consolidate with another entity;
- sell assets except in the ordinary course of business;
- make certain loans and investments; and
- permit trade payables to exceed 90 days.

If an event of default exists under the facility, the lender will be able to accelerate the maturity of the facility and exercise other rights and remedies. Events of default include defaults in payment or performance under the facility, misrepresentations, cross-defaults to other debt or material obligations of Forest Energy Resources, and insolvency, material judgments, certain changes of ownership and any material adverse change affecting Forest Energy Resources.

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MARINER ENERGY, INC.
UNAUDITED PRO FORMA COMBINED CONDENSED BALANCE SHEET
As of September 30, 2005

	Mariner Historical	Merger Adjustments(1)	Mariner Pro Forma Combined
		(in thousands)	
ASSETS			
Current Assets:			
Cash and cash equivalents	$ 4,564	$	$ 4,564
Receivables	50,259		50,259
Deferred tax asset	30,480		30,480
Prepaid expenses and other	18,732	2,874(2)	21,606
Total current assets	104,035	2,874	106,909
Property and Equipment, net	393,258	1,463,846(3)	1,857,104
Goodwill		142,000(3)	142,000
Other Assets, net of amortization	4,916	7,597(2)	12,513
TOTAL ASSETS	$ 502,209	$ 1,616,317	$ 2,118,526
LIABILITIES AND STOCKHOLDERS EQUITY			
Current Liabilities:			
Accounts payable	$ 14,573	$	$ 14,573
Accrued liabilities	88,993	32,491(2)	121,484
Accrued interest	141		141
Derivative liability	76,902	108,031(2)	184,933
Total current liabilities	180,609	140,522	321,131
Long-Term Liabilities:			
Abandonment liability	26,314	116,203(2)	142,517
Deferred income tax	6,468	168,852(4)	175,320
Derivative liability	28,221	17,203(2)	45,424
Bank debt	75,000	200,000(5)	275,000
Note payable	4,000		4,000
New debt			
Other long-term liabilities	3,000		3,000
Total long-term liabilities	143,003	502,258	645,261
Stockholders Equity:			
Common stock	4	5(6)	9
Additional paid-in capital	171,667	973,532(3)	1,145,199
Unearned compensation	(14,548)		(14,548)
Accumulated other comprehensive (loss)	(67,708)		(67,708)
Accumulated retained earnings	89,182		89,182

Total stockholders equity	178,597	973,537	1,152,134
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 502,209	$ 1,616,317	$ 2,118,526

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MARINER ENERGY, INC.
UNAUDITED PRO FORMA COMBINED CONDENSED STATEMENT OF OPERATIONS
For the Nine Months Ended September 30, 2005

	Mariner Historical	Forest Energy Resources, Inc. Historical(7)	Merger Adjustments(1)	Mariner Pro Forma Combined
	(in thousands, except per share data)			
Revenues:				
Oil & gas sales	$ 148,492	$ 326,722	$	$ 475,214
Other revenues	2,753			2,753
Total revenues	151,245	326,722		477,967
Costs and Expenses:				
Lease operating expenses	20,170	59,379		79,549
Transportation expenses	1,697	2,484		4,181
General and administrative expenses	26,726			26,726
Depreciation, depletion and amortization	43,457		201,255(8)	244,712
Impairment of production equipment held for use	498			498
Total costs and expenses	92,548	61,863	201,255	355,666
OPERATING INCOME	58,697	264,859	(201,255)	122,301
Interest:				
Income	696			696
Expense, net of amounts capitalized	(5,416)		(8,010)(9)	(13,426)
Income before taxes	53,977		(209,265)	109,571
Provision for income taxes	(18,414)		(19,936)(10)	(38,350)
NET INCOME	35,563		(229,201)	71,221
Earnings per share:				
Net Income per share basic	1.10			0.86
Net Income per share diluted	1.07			0.85
Weighted average shares outstanding basic	32,438		50,637	83,075
Weighted average shares outstanding diluted	33,313		50,637	83,950

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MARINER ENERGY, INC.
UNAUDITED PRO FORMA COMBINED CONDENSED STATEMENT OF OPERATIONS
For the Year Ended December 31, 2004

	Mariner Historical	Forest Energy Resources, Inc. Historical(7)	Merger Adjustments(1)	Mariner Pro Forma Combined
	(in thousands, except per share data)			
Revenues:				
Oil & gas sales	$ 214,187	$ 453,139	$	$ 667,326
Other revenues				
Total revenues	214,187	453,139		667,326
Costs and Expenses:				
Lease operating expenses	25,484	81,627		107,111
Transportation expenses	3,029	2,175		5,204
General and administrative expenses	8,772			8,772
Depreciation, depletion and amortization	64,911		303,261(8)	368,172
Impairment of production equipment held for use	957			957
Total costs and expenses	103,153	83,802	303,261	490,216
OPERATING INCOME	111,034	369,337	(303,261)	177,110
Interest:				
Income	316			316
Expense, net of amounts capitalized	(6,050)		(7,840)(9)	(13,890)
Income before taxes	105,300		(311,101)	163,536
Provision for income taxes	(36,855)		(20,383)(10)	(57,238)
NET INCOME	68,445		(331,484)	106,298
Earnings per share:				
Net Income per share basic	2.30			1.32
Net Income per share diluted	2.30			1.32
Weighted average shares outstanding basic	29,748		50,637	80,385
Weighted average shares outstanding diluted	29,748		50,637	80,385

Notes to Unaudited Pro Forma Combined Condensed Financial Data

The unaudited Mariner Pro Forma Combined financial data have been prepared to give effect to Mariner s acquisition of the Forest Gulf of Mexico operations, which will be spun off to Forest shareholders. Information under the heading Merger Adjustments gives effect to the adjustments related to the acquisition of the Forest Gulf of Mexico operations. The unaudited pro forma combined condensed statements are not necessarily indicative of the results of Mariner s future operations.

The unaudited pro forma combined financial information has been derived from and should be read together with the historical consolidated financial statements of Mariner and the statements of revenues and direct operating expenses of the Forest Gulf of Mexico operations. The statements of revenues and direct operating expenses of the Forest Gulf of Mexico operations do not include all of the costs of doing business.

(1) Transaction costs consisting of accounting, consulting and legal fees are anticipated to be approximately $12 million. These costs are directly attributable to the transaction and have been excluded from the pro forma financial statements as they represent material nonrecurring charges.

(2) To record other current and long-term assets that we will receive in the spin-off and liabilities that we will assume as a result of the spin-off reflected at their estimated fair market values, including inventory of $2.1 million, abandonment escrows of $0.7 million, gas imbalances of $7.6 million, asset retirement obligations of $146.6 million and derivative liabilities of $125.2 million.

(3) To record the preliminary purchase price allocation to the fair value of assets acquired, including oil and gas properties and goodwill. These adjustments also adjust depreciation, depletion and amortization expense to give effect to the acquisition of the Forest Gulf of Mexico operations and their step-up in value using the unit of production method under the full cost method of accounting.

(4) To record the deferred tax position of the combined company, inclusive of the deferred tax gross-up in connection with the acquisition.

(5) To record $200.0 million of debt that Forest Energy Resources, Inc. will incur under the terms of the distribution agreement. The actual amount of debt to be incurred will be adjusted to reflect the net cash proceeds generated by the Forest Gulf of Mexico operations since June 30, 2005 pursuant to the terms of the distribution agreement. Mariner plans to refinance the debt, which will mature 90 days after the closing, with a revolving credit facility that matures on the fourth anniversary of the closing. Forest Energy Resources, Inc. will be primarily liable for all indebtedness incurred in connection with the spin-off or any refinancing thereof.

(6) To record issuance of 50,637,010 shares of common stock at par value of $.0001 per share.

(7) The Forest Gulf of Mexico operations historically have been operated as part of Forest s total oil and gas operations. No historical GAAP-basis financial statements exist for the Forest Gulf of Mexico operations on a stand-alone basis; however, statements of revenues and direct operating expenses are presented for the year ended December 31, 2004 (audited) and for the nine months ended September 30, 2005 (unaudited).

(8) To adjust depreciation, depletion and amortization expense to give effect to the acquisition of the Forest Gulf of Mexico operations and their step-up in value using the unit of production method under the full cost method of accounting.

(9) To adjust interest expense to give effect to the financing activities in connection with the organization of Forest Energy Resources, Inc. assuming an interest rate of 5.34% for the nine months ended September 30, 2005 and

3.92% for the year ended December 31, 2004 based on the terms of the senior term loan facility to be obtained by Forest Energy Resources. The interest rates used reflect 30-day LIBOR plus 1.50%, or 5.34% as of September 30, 2005 and 3.92% as of December 31, 2004. A change in interest rates of $^{1}/8$ percent would result in a change in interest expense of approximately $0.1 million and $0.2 million for the nine months ended September 30, 2005, and the year ended December 31, 2004, respectively.

(10) To record income tax expense on the combined company results of operations based on a statutory combined federal and state tax rate of 35%.

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Supplemental Pro Forma Combined Oil and Gas Reserve and Standardized Measure Information (Unaudited)

The following unaudited supplemental pro forma oil and natural gas reserve tables present how the combined oil and gas reserve and standardized measure information of Mariner and the Forest Gulf of Mexico operations may have appeared had the businesses actually been combined as of December 31, 2004. The Supplemental Pro Forma Combined Oil and Gas Reserve and Standardized Measure Information is for illustrative purposes only. You should refer to footnote 10 in Mariner s Notes to the Financial Statements beginning on page F-32 and footnote 3 in Forest s Gulf of Mexico Operations Notes to Statements of Revenues and Direct Operating Expenses beginning on page F-39 for additional information presented in accordance with the requirements of Statement of Financial Accounting Standards No. 69, Disclosures About Oil and Gas Producing Activities.

ESTIMATED PRO FORMA COMBINED QUANTITIES OF PROVED RESERVES

	Mariner Historical			Forest Energy Resources, Inc. Historical			Mariner Pro Forma Combined		
	Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas Equivalent (Mmcfe)	Liquids (Mbbl)	Natural Gas (MMcf)	Natural Gas Equivalent (Mmcfe)	Liquids (Mbbl)	Natural Gas (MMcf)	Natural Gas Equivalent (Mmcfe)
December 31, 2003	13,079	127,584	206,060	11,357	295,347	363,489	24,436	422,931	569,549
Revisions of previous estimates	1,249	19,797	27,291	1,693	(2,860)	7,298	2,942	16,937	34,589
Extensions, discoveries and other additions	2,225	28,334	41,684	630	14,449	18,229	2,855	42,783	59,913
Sales of reserves in place									
Production	(2,298)	(23,782)	(37,570)	(3,230)	(61,684)	(81,064)	(5,528)	(85,466)	(118,634)
Purchases of reserves in place				1,200	24,556	31,756	1,200	24,556	31,756
December 31, 2004	14,255	151,933	237,465	11,650(1)	269,808	339,708	25,905(1)	421,741	577,173

(1) Includes 598 Mbbls of natural gas liquids.

ESTIMATED PRO FORMA COMBINED QUANTITIES OF PROVED DEVELOPED RESERVES

Forest Energy Resources, Inc.

	Mariner Historical			Historical			Mariner Pro Forma Combined		
	Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas Equivalent (Mmcfe)	Liquids (Mbbl)	Natural Gas (MMcf)	Natural Gas Equivalent (Mmcfe)	Liquids (Mbbl)	Natural Gas (MMcf)	Natural Gas Equivalent (Mmcfe)
December 31, 2004	6,339	71,361	109,395	9,471	201,759	258,585	15,810	273,120	367,980

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PRO FORMA COMBINED STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

	For the Year Ending December 31, 2004		
	Mariner Historical	Forest Energy Resources, Inc. Historical	Mariner Pro Forma Combined
Future cash inflows	$ 1,601,240	$ 2,155,217	$ 3,756,457
Future production costs	(308,190)	(272,020)	(580,210)
Future development costs	(193,689)	(357,592)	(551,281)
Future income taxes	(285,701)	(412,477)	(698,178)
Future net cash flows	813,660	1,113,128	1,926,788
Discount of future net cash flows at 10% per annum	(319,278)	(187,291)	(506,569)
Standardized measure of discounted future net cash flows	$ 494,382	$ 925,837	$ 1,420,219
Balance, beginning of period	$ 418,159	$ 949,421	$ 1,367,580
Increase (decrease) in discounted future net cash flows:			
Sales and transfers of oil and gas produced, net of production costs	(185,673)	(426,405)	(612,078)
Net changes in prices and production costs	27,767	11,628	39,395
Extensions and discoveries, net of future development and production costs	102,905	88,999	191,904
Development costs during period and net change in development costs	44,417	79,642	124,059
Revision of previous quantity estimates	89,814	28,701	118,515
Sales of reserves in place			
Net change in income taxes	(27,634)	(28,550)	(56,184)
Purchases of reserves in place		100,681	100,681
Accretion of discount before income taxes	41,816	121,720	163,536
Changes in production rates (timing) and other	(17,189)		(17,189)
Balance, end of period	$ 494,382	$ 925,837	$ 1,420,219

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STRENGTHS AND STRATEGIES OF MARINER FOLLOWING THE MERGER

Following the merger we expect Mariner to be an independent oil and gas exploration, development and production company focused offshore in the Gulf of Mexico and onshore in the Permian Basin of West Texas. On a pro forma basis as of December 31, 2004, the combined company had 577 Bcfe of estimated proved reserves. Approximately 64% of these reserves were developed; 36% were undeveloped. Approximately 73% of our estimated proved reserves were natural gas and natural gas liquids, and 27% were oil and condensate. The reserves are geographically distributed approximately 62% on the Gulf of Mexico shelf, 18% in the Gulf of Mexico deepwater and 20% in the Permian Basin in West Texas. As of December 31, 2004, the pro forma PV10 of the combined company was approximately $1.9 billion, and the pro forma standardized measure of discounted future net cash flows attributable to its estimated proved reserves was approximately $1.4 billion. Please see Business Estimated Proved Reserves and The Forest Gulf of Mexico Operations Estimated Proved Reserves for a definition of PV10 and reconciliations of PV10 to the standardized measure of discounted future net cash flows.

Mariner is focused on the generation and development of new Gulf of Mexico deepwater, deep shelf and shelf projects and the development of its existing asset base in West Texas. Historically, Mariner has achieved growth through the drill bit; however, as part of our growth strategy, we also seek to acquire assets that provide acceptable risk-adjusted rates of return and have significant potential for further reserve additions through development and exploitation activities.

We believe Mariner s core resources and strengths include:

- our high-quality assets with geographic and geological diversity;
- our successful track record of finding and developing oil and gas reserves; and
- our depth of operating experience.

The integration and further development and exploitation of the Forest Gulf of Mexico operations into our business will further diversify and, in our view, complement our existing business, provide additional resources for future growth beyond the producing assets acquired, and afford a larger scale to increase our ability to compete effectively. We expect the effectiveness of our growth strategy to be enhanced by the addition of the Forest Gulf of Mexico assets.

High-Quality Assets. We believe our asset base has significant potential:

- Our deepwater projects have the potential to provide large reserves, high production volumes and substantial cash flow. Approximately 65 Bcfe of our undeveloped estimated proved reserves as of December 31, 2004, are located in our high-impact deepwater projects Swordfish, Pluto, Rigel, Baccarat, and Daniel Boone. The Baccarat project commenced production in July 2005 (although production was shut-in due to Hurricane Rita and recommenced in January 2006), and the Swordfish project commenced production in October 2005. Notwithstanding delays caused primarily by 2005 hurricane activity, we believe Pluto and Rigel will commence production in the second quarter of 2006. Proved undeveloped reserves attributable to those projects have been recategorized as proved developed reserves. Daniel Boone is currently scheduled for production in 2008.

- The Gulf of Mexico is an area that offers substantial growth opportunities, and we expect to continue to generate shelf, deep shelf and deepwater Gulf of Mexico prospects. The Forest Gulf of Mexico assets will more than double our existing undeveloped acreage position to approximately 465,000 net acres and increase our total net leasehold acreage offshore to nearly 1 million acres, providing numerous exploration, exploitation and development opportunities. We believe the additional acreage also will provide increased exposure to farm-out opportunities from other oil and gas operators. Our team of geoscientists currently has access to seismic data from multiple, recent vintage 3-D seismic databases covering more than 6,600 blocks in the Gulf of Mexico that we intend to continue to use to develop prospects on acreage being evaluated for leasing and to develop and further refine prospects on our expanded acreage position. The combination of our

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undeveloped acreage position, inventory of development prospects, seismic data and technical knowledge should enhance our ability to select projects with the greatest return potential for future development. We will also gain access to a significant infrastructure in the shelf that we believe will provide substantial cost efficiencies to the combined operations.

Our West Texas assets provide stable cash flow and long-lived reserves, with significant development opportunities. In West Texas, during the three years ended December 31, 2004, we drilled 105 wells, all commercially successful, added approximately 76 Bcfe of estimated proved reserves, and increased our average daily production by more than 400%. Our 52 Bcfe of undeveloped estimated proved reserves in West Texas includes 162 locations. Our recent West Texas acquisition adds to our asset base an approximate 35% working interest in over 200 existing producing wells and, we believe, will provide future infill development opportunities, much like our Aldwell unit. This recent acquisition, in conjunction with our existing West Texas acreage, gives Mariner an inventory of multi-year development drilling opportunities.

Successful Track Record of Finding and Developing Oil and Gas Reserves. In the three-year period ended December 31, 2004, Mariner deployed approximately $337 million of capital on acquisitions, exploration and development, while adding approximately 191 Bcfe of proved reserves and producing approximately 111 Bcfe. In addition to our successful West Texas drilling program, in the three-year period ended December 31, 2004, we have participated in the drilling of 33 exploration wells in the Gulf of Mexico, with 15 of these wells resulting in the discovery of commercial oil and gas reserves.

Our technical professionals average more than 20 years of experience in the exploration and production business, much of it with major oil companies, including extensive experience in the Gulf of Mexico. The addition of experienced Forest personnel to Mariner s team of geoscientists and technical and operational professionals should further enhance our ability to generate and maintain an inventory of high-quality drillable prospects and to further develop and exploit our assets.

We seek to mitigate our risk in drilling projects by entering into arrangements with industry partners in which they agree to pay a disproportionate share of dry hole costs and compensate us for expenses incurred in prospect generation. We intend to continue our practice of sharing costs of offshore exploration and development activities by selling interests in projects to industry partners. From time to time, we may sell entire interests in offshore prospects in order to better diversify our portfolio. We also enter into trades or farm-in transactions whereby we acquire interests in third-party generated prospects. We expect more opportunities to participate in these prospects as a result of the scale and increased cash flow the merger will bring.

Depth of Operating Experience. Our engineers have extensive experience in offshore Gulf of Mexico completion and production techniques, both in the deepwater and on the shelf. We have extensive experience and a successful track record in the use of subsea tieback technology to connect offshore wells to existing production facilities. This technology facilitates production from offshore properties without the necessity of fabrication and installation of more costly platforms and top side facilities that typically require longer lead times. We believe the use of subsea tiebacks in appropriate projects enables us to bring production online more quickly, makes target prospects more profitable, and allows us to exploit reserves that may otherwise be considered non-commercial because of the high cost of infrastructure. In the Gulf of Mexico, in the three years ended December 31, 2004, we were directly involved in thirteen projects (five of which we operated) utilizing subsea tieback systems in water depths ranging from 475 feet to more than 7,000 feet, and in five projects (three of which we operated) developed through the use of platforms.

Mariner has proven to be an effective and efficient operator in West Texas, as evidenced by our results there in recent years. In addition to conducting a successful drilling program, increasing our production and expanding our asset base, we have improved our net operating margin by reducing our operating costs and increasing our realized share of production.

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We expect that our acquisition of the Forest Gulf of Mexico assets and the scale it brings to our business will:

- reduce our concentration risk;
- provide many exploration, exploitation and development opportunities;
- enable us to increase the number of our internally-generated prospects;
- expand our sphere of influence and enhance our ability to participate in prospects generated by other operators; and
- add a significant cash flow generating resource that will improve our ability to compete effectively in the Gulf of Mexico and provide funding for acquisition projects.

We believe we are well positioned to optimize the Forest Gulf of Mexico assets through aggressive and timely exploitation. Our diverse, high-quality assets, our ability to find and develop oil and gas reserves, and our operating experience should provide a strong platform from which to grow and create value for our shareholders.

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MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Overview

On March 2, 2004, Mariner s former indirect parent, Mariner Energy LLC, merged with MEI Acquisitions, LLC, an affiliate of the private equity funds, Carlyle/ Riverstone Global Energy and Power Fund II, L.P. and ACON Investments LLC. Prior to the merger, we were owned indirectly by JEDI, which was an indirect wholly-owned subsidiary of Enron Corp. The gross merger consideration was $271.1 million (which excludes $7.0 million of acquisition costs and other expenses paid directly by Mariner), $100 million of which was provided as equity by our new owners. As a result of the merger, we are no longer affiliated with Enron Corp. See Business Enron Related Matters. The merger did not result in a change in our strategic direction or operations. The financial information contained herein is presented in the style of Pre-2004 Merger activity (for all periods prior to March 2, 2004) and Post-2004 Merger activity (for the March 3, 2004 through December 31, 2004 period) to reflect the impact of the restatement of assets and liabilities to fair value as required by push-down purchase accounting at the March 2, 2004 merger date. The application of push-down accounting had no effect on our 2004 results of operations other than immaterial increases in depreciation, depletion and amortization expense and interest expense and a related decrease in our provision for income taxes. To facilitate management s discussion and analysis of financial condition and results of operations, we have presented 2004 financial information as Pre-2004 Merger (for the January 1 through March 2, 2004 period), Post-2004 Merger (for the March 3, 2004 through December 31, 2004 period), Combined (for the full period from January 1 through December 31, 2004), Post-2004 Merger (for the March 3, 2004 through September 30, 2004 period) and Combined (for the full period from January 1, 2004 through September 30, 2004). The combined presentation does not reflect the adjustments to our statement of operations that would be reflected in a pro forma presentation. However, because such adjustments are not material, we believe that our combined presentation presents a fair presentation and facilitates an understanding of our results of operations.

In March 2005, we completed a private placement of 16,350,000 shares of our common stock to qualified institutional buyers, non-U.S. persons and accredited investors, which generated approximately $229 million of gross proceeds, or approximately $211 million net of initial purchaser s discount, placement fee and offering expenses. Our former sole stockholder, MEI Acquisitions Holdings, LLC, also sold 15,102,500 shares of our common stock in the private placement. We used $166 million of the net proceeds from the sale of 12,750,000 shares of common stock to purchase and retire an equal number of shares of our common stock from our former sole stockholder. We used $39 million of the remaining net proceeds of approximately $45 million to repay borrowings drawn on our credit facility, and the balance to pay down $6 million of a $10 million promissory note payable to JEDI. See Business Enron Related Matters. As a result, after the private placement, an affiliate of MEI Acquisitions Holdings, LLC beneficially owned approximately 5.3% of our outstanding common stock. See Security Ownership of Certain Beneficial Owners and Management.

We are an independent oil and natural gas exploration, development and production company with principal operations in the Gulf of Mexico and the Permian Basin in West Texas. In the Gulf of Mexico, our areas of operation include the deepwater and the shelf area. We have been active in the Gulf of Mexico and West Texas since the mid-1980s. During the last three years, as a result of increased drilling of shelf prospects and development drilling in our Aldwell Unit, we have evolved from a company with primarily a deepwater focus to one with a balance of exploitation and exploration of the Gulf of Mexico deepwater and shelf, and longer-lived Permian Basin properties.

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas and our ability to find, develop and acquire oil and gas reserves that are economically recoverable while controlling and reducing costs. The energy markets have historically been very volatile. Commodity prices are currently at or near historical highs and may fluctuate and decline significantly in the future. Although we attempt to mitigate the impact of price declines through our hedging strategy, a substantial or extended decline in oil and natural gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of natural gas and oil reserves that we can economically produce and our access to capital.

Recent Developments

Approximately 29 Mmcfe per day of natural gas and approximately 3,000 bbls per day of oil and condensate net to our interest were initially shut-in as a result of the effects of Hurricane Katrina in August 2005. The majority of this production was returned within two weeks of the hurricane, and substantially all within three weeks of the hurricane. Additionally, we are experiencing delays in startup of three of our projects primarily as a result of Hurricane Katrina which is anticipated to defer commencement of production to as late as the second quarter of 2006. Approximately 60 MMcfe per day of production net to our interest was shut-in initially as a result of the effects of Hurricane Rita in late September 2005. Approximately 53 MMcfe per day of production, or approximately 90% of our pre-hurricane production, was restored within two weeks of the hurricane. Our operated platforms appear to have sustained minimal damage attributable to the storm. First reports from operators of other facilities handling our production indicated varying degrees of damage to their facilities, the full extent of which may not be known for some time. Although a submersible rig engaged in drilling operations on our East Cameron Block 79 property was moved off location by Hurricane Rita, a substitute rig was subsequently provided, the damage to the well was repaired and drilling recommenced in the last quarter of 2005. Other planned operations also are delayed as a result of the effects of both hurricanes. We cannot estimate a range of loss arising from the hurricanes until we are able to more completely assess the impacts on our properties and the properties of our operational partners. Until we are able to complete all the repair work and submit costs to our insurance underwriters for review, the full extent of our insurance recovery and the resulting net cost to us for Hurricanes Katrina and Rita will be unknown. For the insurance period ending September 30, 2005, we carry a $3.0 million annual deductible and a $.375 million single occurrence deductible.

We entered into an agreement effective in October 2005 covering approximately 33,000 acres in West Texas, pursuant to which, upon closing, we acquired an approximate 35% working interest in approximately 200 existing producing wells effective November 1, 2005, and committed to drill an additional 150 wells within a four year period, funding $36.5 million of our partner s share of drilling costs for such 150-well drilling program. We will obtain an assignment of an approximate 35% working interest in the entire committed acreage upon completion of the 150-well program.

Nine Months Ended September 30, 2005 Highlights

During the first nine months of 2005, we recognized net income of $35.6 million on total revenues of $151.2 million compared to net income of $50.5 million on total revenues of $162.3 million in the first nine months of 2004. Net income decreased 30% compared to the first nine months of 2004, primarily due to recognizing $17.6 million of stock compensation expense in the first nine months of 2005, and a 21% decrease in production, partially offset by higher realized net oil and gas prices. We produced approximately 22.5 Bcfe during the first nine months of 2005 and our average daily production rate was 82 Mmcfe compared to 28.4 Bcfe, or 104 Mmcfe per day, for the same period in 2004. Production during the third quarter of 2005 was negatively impacted by the effects of the 2005 hurricane season. We invested approximately $130.3 million in oil and natural gas properties in the first nine months of 2005, compared to $101.0 million in the same period in 2004.

Our first nine months 2005 results reflect the private placement of an additional 3.6 million shares of stock in March. The net proceeds of approximately $45 million generated by the private placement were used to repay existing debt. We also granted 2,267,270 shares of restricted stock and options to purchase 809,000 shares of stock in the first nine months of 2005 and recorded compensation expense of $17.6 million in the first nine months of 2005 related to the restricted stock and options.

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2004 Highlights

We recognized net income of $68.4 million in 2004 compared to net income of $38.2 million in 2003. The increase in net income was primarily the result of improvements in operating results, including a 13% increase in production volumes, a 21% improvement in the net commodity prices realized by us (before the effects of hedging) and an 8% decrease in lease operating expenses and transportation expenses on a per unit basis. These improvements were partially offset by an 8% increase in general and administrative expenses and a 34% increase in depreciation, depletion, and amortization expenses. Our hedging results also improved by $9.7 million to a $19.8 million loss, from a $29.5 million loss in the prior year. In addition, we recorded income tax expenses of $36.9 million in 2004 compared to $9.4 million in 2003.

We have incurred and expect to continue to incur substantial capital expenditures. However, for the three years ended December 31, 2004, our capital expenditures of $337.3 million have been below our combined cash flow from operations and proceeds from property sales.

During 2004, we increased our proved reserves by approximately 69 Bcfe, bringing estimated proved reserves as of December 31, 2004 to approximately 237.5 Bcfe after 2004 production of 37.6 Bcfe.

We had $2.5 million and $60.2 million in cash and cash equivalents as of December 31, 2004 and December 31, 2003, respectively.

Production

Three of our shelf properties, Ewing Bank 977 (Dice), West Cameron 333 (Royal Flush) and High Island 46 (Green Pepper) began producing in the first quarter of 2005. Our production for the first nine months of 2005 averaged approximately 53 MMcf of natural gas per day and approximately 4,900 barrels of oil per day or a total of approximately 82 MMcfe per day.

In the third quarter of 2005 our production was negatively impacted by Hurricanes Katrina and Rita. Production shut-in and deferred because of the hurricanes impact totaled approximately 1.3 Bcfe during the third quarter of 2005. Currently approximately 7 MMcfe per day of production remains shut-in awaiting repairs, primarily associated with our Baccarat property. While we believe physical damage to our existing platforms and facilities was relatively minor from both hurricanes, the effects of the storms caused damage to onshore pipeline and processing facilities that resulted in a portion of our production being temporarily shut-in, or in the case of our Viosca Knoll 917 (Swordfish) project, postponed. In addition, Hurricane Katrina caused damage to platforms that host three of our development projects: Mississippi Canyon 718 (Pluto), Mississippi Canyon 296 (Rigel), and Mississippi Canyon 66 (Ochre). Repairs to these facilities may take up to six months, pushing commencement of production on these projects into 2006.

Our December 2004 total production averaged approximately 58 MMcf of natural gas per day and approximately 5,700 barrels of oil per day or total equivalents of approximately 92 MMcfe per day. Natural gas production comprised approximately 63% of total production. In September 2004, Mariner incurred damage from Hurricane Ivan that affected our Mississippi Canyon 66 (Ochre) and Mississippi Canyon 357 fields. Production from Mississippi Canyon 357 was shut-in until March 2005, when necessary repairs were completed and production recommenced. Production from Mississippi Canyon 66 (Ochre) remains shut-in and is expected to recommence in the first quarter of 2006. This field was producing at a net rate of approximately 6.5 MMcfe per day immediately prior to the hurricane.

Historically, a majority of our total production has been comprised of natural gas. We anticipate that our concentration in natural gas production will continue. As a result, Mariner s revenues, profitability and cash flows will be more sensitive to natural gas prices than to oil and condensate prices.

Generally, our producing properties in the Gulf of Mexico will have high initial production rates followed by steep declines. As a result, we must continually drill for and develop new oil and gas reserves to replace those being depleted by production. Substantial capital expenditures are required to find and develop these reserves. Our challenge is to find and develop reserves at economic rates and commence production of these reserves as quickly and efficiently as possible.

Deepwater discoveries typically require a longer lead time to bring to productive status. Since 2001, we have made several deepwater discoveries that are in various stages of development. We commenced production at our Green Canyon 178 (Baccarat) project in the third quarter of 2005. However, damage sustained by the host facility during Hurricane Rita caused production to be shut-in. Production is expected to recommence in the first quarter of 2006. We commenced production at our Swordfish project in the fourth quarter of 2005. We currently anticipate commencing production in the second quarter of 2006 at our Pluto, Rigel and Ewing Banks 921 (North Black Widow) projects. However, as described above, Hurricanes Katrina and Rita have delayed start up of these projects from their original anticipated commencement dates. Other uncertainties, including scheduling, weather, and construction lead times, could cause further delays in the start up of any one or all of the projects.

Oil and Gas Property Costs

In the nine months ended September 30, 2005, we incurred approximately $130.4 million in capital expenditures with 70% related to development activities primarily at our Aldwell Unit and for our Viosca Knoll 917 (Swordfish), Mississippi Canyon 718 (Pluto) and Mississippi Canyon 296 (Rigel) offshore projects. We also expended $10.0 million for the acquisition of oil and gas property interests in the first nine months of 2005, comprised of $3.5 million for properties located in the West Texas Permian Basin area, $5.0 million for Atwater Valley 426 (Bass Lite) and $1.5 million for East Breaks 513/514/558 (LaSalle). We incurred approximately $23.6 million of exploration capital expenditures in the first nine months of 2005.

During 2004, we incurred approximately $148.9 million in capital expenditures with 60% related to development activities, 32% related to exploration activities, including the acquisition of leasehold and seismic, and the remainder related to acquisitions and other items (primarily capitalized overhead and interest).

We spent approximately $88.6 million in development capital expenditures in 2004 primarily on Aldwell Unit development and for Viosca Knoll 917 (Swordfish), Mississippi Canyon 718 (Pluto), and West Cameron 333 (Royal Flush) offshore projects.

All capital expenditures for exploration activities relate to offshore projects, and approximately 30% of exploration capital expended during 2004 was for leasehold, seismic, and geological and geophysical costs. During 2004 we participated in fourteen exploration wells, with seven being successful. We incurred approximately $47.9 million of exploration capital expenditures in 2004.

We anticipate that, based on our current budget, capital expenditures in 2005 will approximate $250 million with approximately 48% allocated to development projects, 27% to exploration activities, 21% to acquisitions and the remainder to other items (primarily capitalized overhead and interest). However, the effects of Hurricanes Katrina and Rita may delay some planned operations into 2006.

Oil and Gas Reserves

We have maintained our reserve base through exploration and exploitation activities despite selling 79.7 Bcfe of our reserves since the fourth quarter of 2001. Historically, we have not acquired significant reserves through acquisition activities. As of December 31, 2004, Ryder Scott estimated our net proved reserves at approximately 237.5 Bcfe, with a PV10 of approximately $668 million and a standardized measure of discounted future net cash flows attributable to our estimated proved reserves of approximately $494.4 million. Please see Business Estimated Proved Reserves for a definition of PV10 and a reconciliation of PV10 to the standardized measure of discounted future net cash flows. To generate our net proved reserves as of June 30, 2005, our management reviewed and updated our historical lease operating expenses, updated our transportation and basis differentials, updated NYMEX prices, adjusted for roll-off and production performance since December 31, 2004, added any new proved undeveloped reserves (including those resulting from our Bass Lite project), updated the categorization of our projects

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as either proved undeveloped, proved developed producing or proved behind pipe, and adjusted capital expenditures and timing of cash outlays. See Business Estimated Proved Reserves for more information concerning our reserve estimates.

The development drilling at our West Texas Aldwell Unit and Gulf of Mexico deepwater divestitures have significantly changed our reserve profile since 2001. Proved reserves as of December 31, 2004 were comprised of 48% West Texas Permian Basin, 15% Gulf of Mexico shelf and 37% Gulf of Mexico deepwater compared to 20% West Texas Permian Basin, 15% Gulf of Mexico shelf and 65% Gulf of Mexico deepwater as of December 31, 2001. Proved undeveloped reserves were approximately 54% of total proved reserves as of December 31, 2004. Approximately 39% of proved undeveloped reserves were related to our West Texas Aldwell Unit, where we had 100% development drilling success on 105 wells from 2002 through 2004.

Since December 31, 1997, we have added proved undeveloped reserves attributable to 12 deepwater projects. Of those projects, ten have either been converted to proved developed reserves or sold as indicated in the following table.

Property	**Net Proved Undeveloped Reserves (Bcfe)(1)**	**Year Added**	**Year Converted to Proved Developed or Sold**
Mississippi Canyon 718 (Pluto)(2)	25.1	1998	2000 (100% converted to proved developed)
Ewing Bank 966 (Black Widow)	14.0	1999	2000 (100% converted to proved developed)
Mississippi Canyon 773 (Devils Tower)	28.0	2000	2001 (100% of Mariner s interest sold)
Mississippi Canyon 305 (Aconcagua)	19.2	2000	2001 (100% of Mariner s interest sold)
Green Canyon 472/473 (King Kong)	25.5	2000	2002 (100% converted to proved developed)
Green Canyon 516 (Yosemite)	14.9	2001	2002 (100% converted to proved developed)
East Breaks 579 (Falcon)	66.8	2001	2002 (50% of Mariner s interest sold) 2003 (all of Mariner s remaining interest sold)
Viosca Knoll 917 (Swordfish)	13.4	2001	2005 (100% converted to proved developed)
Green Canyon 178 (Baccarat)	4.0	2004	2005 (100% converted to proved developed)
Mississippi Canyon 296/252 (Rigel)	22.4	2003	2005 (75% converted to proved developed/ 25% remains undeveloped)

(1) Net proved undeveloped reserves attributable to the project in the year it was first added to our proved reserves.

(2) This field was shut-in in April 2004 pending the drilling of a new well and installation of an extension to the existing infield flowline and umbilical. As a result, as of December 31, 2004, 9.0 Bcfe of our net proved reserves attributable to this project were classified as proved undeveloped reserves. We expect production from Pluto to recommence in the second quarter of 2006.

The proved undeveloped reserves attributable to the remaining two deepwater projects were added as follows:

Property	**Net Proved Undeveloped Reserves (Bcfe)(1)**	**Year Added**	**Year Expected to Convert to Proved Developed Status**
Green Canyon 646 (Daniel Boone)	16.4	2003	2007
Atwater Valley 380/381/382/425/426 (Bass Lite)	30.7	2005	2007

(1) Net proved undeveloped reserves attributable to the project as of June 30, 2005.

Oil and Natural Gas Prices and Hedging Activities

Prices for oil and natural gas can fluctuate widely, thereby affecting the amount of cash flow available for capital expenditures, our ability to borrow and raise additional capital and the amount of oil and natural gas that we can economically produce. Recently, oil and natural gas prices have been at or near historical highs and very volatile as a result of various factors, including weather, industrial demand, war and political instability and uncertainty related to the ability of the energy industry to provide supply to meet future demand.

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas and our ability to find, develop and acquire oil and gas reserves that are economically recoverable while controlling and reducing costs. A substantial or extended decline in oil and natural gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and natural gas reserves that we can economically produce and access to capital.

We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in oil and natural gas prices. Typically, our hedging strategy involves entering into commodity price swap arrangements and costless collars with third parties. Price swap arrangements establish a fixed price and an index-related price for the covered commodity. When the index-related price exceeds the fixed price, we pay the third party the difference, and when the fixed price exceeds the index-related prices, the third party pays us the difference. Costless collars establish fixed cap (maximum) and floor (minimum) prices as well as an index-related price for the covered commodity. When the index-related price exceeds the fixed cap price, we pay the third party the difference, and when the index-related price is less than the fixed floor price, the third party pays us the difference. While our hedging arrangements enable us to achieve a more predictable cash flow, these arrangements also limit the benefits of increased prices. As a result of increased oil and natural gas prices, we incurred cash hedging losses of $27.7 million in 2004, of which $7.9 million relates to the hedge liability recorded at the March 2, 2004 merger date. Major challenges related to our hedging activities include a determination of the proper production volumes to hedge and acceptable commodity price levels for each hedge transaction. Our hedging activities may also require that we post cash collateral with our counterparties from time to time to cover credit risk. We had no collateral requirements as of December 31, 2004 or September 30, 2005.

In accordance with purchase price accounting implemented at the time of the merger of our former indirect parent company on March 2, 2004, we recorded the mark-to-market liability of our hedge contracts at such date totaling $12.4 million as a liability on our balance sheet. As of December 31, 2004, the amount of our mark-to-market hedge liabilities totaled $22.4 million. See Liquidity and Capital Resources Commodity Prices and Related Hedging Activities.

For the year ended December 31, 2004, assuming a totally unhedged position, our price sensitivity for 2004 historical net revenues for a 10% change in average oil prices and average gas prices received is approximately $8.9 million and $14.5 million, respectively. For the nine months ended September 30, 2005, assuming a totally unhedged position, our price sensitivity for net revenues in the first nine months of 2005 for a 10% change in average oil prices and average gas prices received is approximately $6.7 million and $10.5 million, respectively.

Operating Costs

We classify our operating costs as lease operating expense, transportation expense, and general and administrative expenses. Lease operating expenses are comprised of those costs and expenses necessary to produce oil and gas after an individual well or field has been completed and prepared for production. These costs include direct costs such as field operations, general maintenance expenses, work-overs, and the costs associated with production handling agreements for most of our deep water fields. Lease operating expenses also include indirect costs such as oil and gas property insurance and overhead allocations in accordance with joint operating agreements. We also include severance, production, and ad valorem taxes as lease operating expenses.

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Transportation costs are generally variable costs associated with transportation of product to sales meters from the wellhead or field gathering point. General and administrative include employee compensation costs (including stock compensation expense), the costs of third party consultants and professionals, rent and other costs of leasing and maintaining office space, the costs of maintaining computer hardware and software, and insurance and other items.

Critical Accounting Policies and Estimates

Our discussion and analysis of Mariner s financial condition and results of operations are based upon financial statements that have been prepared in accordance with GAAP in the U.S. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in Note 1 to our financial statements. We analyze our estimates, including those related to oil and gas revenues, oil and gas properties, fair value of derivative instruments, income taxes and contingencies and litigation, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our financial statements:

Oil and Gas Properties

Oil and gas properties are accounted for using the full-cost method of accounting. All direct costs and certain indirect costs associated with the acquisition, exploration and development of oil and gas properties are capitalized. Amortization of oil and gas properties is provided using the unit-of-production method based on estimated proved oil and gas reserves. No gains or losses are recognized upon the sale or disposition of oil and gas properties unless the sale or disposition represents a significant quantity of oil and gas reserves, which would have a significant impact on depreciation, depletion and amortization. The net carrying value of proved oil and gas properties is limited to an estimate of the future net revenues (discounted at 10%) from proved oil and gas reserves based on period-end prices and costs.

The costs of unproved properties are excluded from amortization using the full-cost method of accounting. These costs are assessed quarterly for possible inclusion in the full-cost property pool based on geological and geophysical data. If a reduction in value has occurred, costs being amortized are increased. The majority of the costs relating to our unproved properties will be evaluated over the next three years.

Proved Reserves

Our most significant financial estimates are based on estimates of proved natural gas and oil reserves. Estimates of proved reserves are key components of our unevaluated properties, our rate for recording depreciation, depletion and amortization and our full cost ceiling limitation. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future revenues, rates of production and timing of development expenditures, including many factors beyond our control. The estimation process relies on assumptions and interpretations of available geologic, geophysical, engineering and production data, and the accuracy of reserve estimates is a function of the quality and quantity of available data. Our reserves are fully engineered on an annual basis by Ryder Scott, our independent petroleum engineers.

Compensation Expense

As a result of the adoption of SFAS Statement No. 123(R), we will record compensation expense for the fair value of restricted stock and stock options that were granted on March 11, 2005 pursuant to our Equity Participation Plan and Stock Incentive Plan and for the fair value of subsequent grants of stock options or restricted stock made pursuant to our Stock Incentive Plan. In general, compensation expense will be determined at the date of grant based on the fair value of the stock or options granted.

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The fair value of restricted stock that we granted following the closing of the private equity placement pursuant to our Equity Participation Plan was estimated to be $31.7 million. The fair value will be amortized to compensation expense over the applicable vesting periods. Stock options and restricted stock granted under our Stock Incentive Plan will also result in recognition of compensation expense in accordance with FASB No. 123(R). For more information concerning our Equity Participation Plan, see Management of Mariner Equity Participation Plan.

Revenue Recognition

We recognize oil and gas revenue from our interests in producing wells as oil and gas from those wells is produced and sold under the entitlements method. Oil and gas volumes sold are not significantly different from our share of production.

Income Taxes

Our taxable income through 2004 has been included in a consolidated U.S. income tax return with our former indirect parent company, Mariner Energy LLC. The intercompany tax allocation policy provides that each member of the consolidated group compute a provision for income taxes on a separate return basis. We record income taxes using an asset and liability approach which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax bases of assets and liabilities. Valuation allowances are established when necessary to reduce deferred tax assets to the amount more likely than not to be recovered. In February 2005, Mariner Energy LLC was merged into us, and we will file our own income tax return following the effective date of that merger.

Capitalized Interest Costs

We capitalize interest based on the cost of major development projects which are excluded from current depreciation, depletion, and amortization calculations.

Accrual for Future Abandonment Costs

SFAS No. 143, Accounting for Asset Retirement Obligations, addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 requires that the fair value of a liability for an asset s retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized.

Hedging Program

In June 1998 the FASB issued SFAS No. 133, Accounting for Derivative Instruments and Certain Hedging Activities. In June 2000 the FASB issued SFAS No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activity, an Amendment of SFAS No. 133. SFAS No. 133 and SFAS No. 138 require that all derivative instruments be recorded on the balance sheet at their respective fair values.

Mariner utilizes derivative instruments, typically in the form of natural gas and crude oil price swap agreements and costless collar arrangements, in order to manage price risk associated with future crude oil and natural gas production. These agreements are accounted for as cash flow hedges. Gains and losses resulting from these transactions are recorded at fair market value and deferred to the extent such amounts are effective. Such gains or losses are recorded in AOCI as appropriate, until recognized as operating income as the physical production hedged by the contracts is delivered.

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The net cash flows related to any recognized gains or losses associated with these hedges are reported as oil and gas revenues and presented in cash flows from operations. If the hedge is terminated prior to expected maturity, gains or losses are deferred and included in income in the same period as the physical production hedged by the contracts is delivered.

The conditions to be met for a derivative instrument to qualify as a cash flow hedge are the following: (i) the item to be hedged exposes Mariner to price risk; (ii) the derivative reduces the risk exposure and is designated as a hedge at the time the derivative contract is entered into; and (iii) at the inception of the hedge and throughout the hedge period there is a high correlation of changes in the market value of the derivative instrument and the fair value of the underlying item being hedged.

When the designated item associated with a derivative instrument matures, is sold, extinguished or terminated, derivative gains or losses are recognized as part of the gain or loss on sale or settlement of the underlying item. When a derivative instrument is associated with an anticipated transaction that is no longer expected to occur or if correlation no longer exists, the gain or loss on the derivative is recognized in income to the extent the future results have not been offset by the effects of price or interest rate changes on the hedged item since the inception of the hedge.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from these estimates.

Results of Operations

For certain information with respect to our oil and natural gas production, average sales price received and expenses per unit of production for the three years ended December 31, 2004, see Business Production.

Nine Months Ended September 30, 2005 compared to Nine Months Ended September 30, 2004

Operating and Financial Results for the Nine Months Ended September 30, 2005 Compared to the Nine Months Ended September 30, 2004

		Non-GAAP Combined	Post-Merger	Pre-Merger
	Nine Months Ended September 30,		Period from March 3, 2004 through September 30, 2004	Period from January 1, 2004 through March 2, 2004
Summary Operating Information:	**2005**	**2004**	**2004**	**2004**
	(in thousands, except average sales price)			
Net production:				
Oil (MBbls)	1,336	1,748	1,335	413
Natural gas (MMcf)	14,508	17,959	13,726	4,233
Total (Mmcfe)	22,521	28,444	21,731	6,713
Average daily production (Mmcfe/d)	82	104	102	112
Hedging activities:				
Oil revenues (loss)	$ (13,421)	$ (6,874)	$ (6,188)	$ (686)
Gas revenues (loss)	(9,979)	(1,010)	(2,441)	1,431

Total hedging revenues (loss)	$ (23,400)	$ (7,884)	$ (8,629)	$ 745

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Summary Operating Information:	Non-GAAP Combined Nine Months Ended September 30, 2005	Non-GAAP Combined Nine Months Ended September 30, 2004	Post-Merger Period from March 3, 2004 through September 30, 2004	Pre-Merger Period from January 1, 2004 through March 2, 2004
	(in thousands, except average sales price)			
Average Sales Prices:				
Oil (per Bbl) realized(1)	$ 40.12	$ 32.78	$ 33.41	$ 30.75
Oil (per Bbl) unhedged	50.17	36.71	38.05	32.41
Natural gas (per Mcf) realized(1)	6.54	5.85	5.68	6.39
Natural gas (per Mcf) unhedged	7.23	5.90	5.86	6.05
Total natural gas equivalent ($/Mcfe) realized(1)	6.59	5.71	5.64	5.92
Total natural gas equivalent ($/Mcfe) unhedged	7.63	5.98	6.04	5.81
Oil and gas revenues:				
Oil sales	$ 53,579	$ 57,285	$ 44,576	$ 12,709
Gas sales	94,913	105,005	77,950	27,055
Total oil and gas revenues	$ 148,492	$ 162,290	$ 122,526	$ 39,764
Other revenues	2,753			
Lease operating expenses	20,170	19,194	15,073	4,121
Transportation expenses	1,697	4,814	3,744	1,070
Depreciation, depletion and amortization	43,457	48,094	37,464	10,630
General and administrative expenses	26,726	7,305	6,174	1,131
Net interest expense (income)	4,720	4,127	4,213	(86)
Income before taxes	53,977	77,799	54,901	22,898
Provision for income taxes	18,414	27,293	19,221	8,072

(1) Average realized prices include the effects of hedges.

Net production during the nine months ended September 30, 2005 decreased approximately 21% to 22.5 Bcfe from 28.4 Bcfe in the same period of 2004 primarily due to decreased Gulf of Mexico production, partially offset by increased onshore production. Mariner s production was negatively impacted during the third quarter of 2005 due to hurricane activity, primarily Katrina and Rita. Production shut-in and deferred because of the hurricanes impact totaled approximately 1.3 Bcfe during the third quarter of 2005. As of September 30, 2005, approximately 7 MMcfe per day of production remained shut-in awaiting repairs, primarily associated with our Baccarat property (although, production therefrom recommenced in January 2006). Additionally, production that was anticipated to commence in the third quarter of 2005 at our Swordfish, Pluto, and Rigel development projects has been delayed until the fourth quarter of 2005 for Swordfish, and into 2006 at Pluto and Rigel, awaiting repairs to host facilities.

Increased development drilling at our Aldwell unit in West Texas contributed to a 61% increase in onshore production to an average of approximately 17.1 Mmcfe per day in the first nine months of 2005 from an average of approximately 10.5 Mmcfe per day in the first nine months of 2004.

In the deepwater Gulf of Mexico, production decreased approximately 30% to an average of approximately 33 Mmcfe per day in the first nine months of 2005 compared to an average of approximately 47 Mmcfe per day in the first nine months of 2004. The decrease was largely due to reduced production at our Black Widow, Yosemite and Pluto fields. Pluto was shut-in in April 2004 pending drilling of the new Mississippi Canyon 674 #3 well and installation of an extension to the existing subsea facilities. Production at Black Widow and Yosemite are undergoing expected declines.

In the Gulf of Mexico shelf, production decreased by approximately 30% to an average of approximately 32 Mmcfe per day in the first nine months of 2005 from an average of approximately 46 Mmcfe per day in the first nine months of 2004. About 6.2 Mmcfe per day of the decrease is attributable to our Ochre field which remains shut-in due to the effects of Hurricane Ivan in September 2004. Production from three new shelf discoveries (Green Pepper, Royal Flush, and Dice) and production from the 2004 acquisition of interests in five offshore fields offset normal declines at our other Gulf of Mexico shelf fields.

Hedging activities in the first nine months of 2005 decreased our average realized natural gas price received by $0.69 per Mcf and revenues by $10.0 million, compared with a decrease of $0.05 per Mcf and revenues of $1.0 million for the same period in 2004. Our hedging activities with respect to crude oil during the first nine months of 2005 decreased the average sales price received by $10.05 per barrel and revenues by $13.4 million compared with a decrease of $3.93 per barrel and revenues of $6.9 million for the same period in 2004.

Oil and gas revenues decreased 6% to $148.5 million in the first nine months of 2005 when compared to first nine months 2004 oil and gas revenues of $162.3 million, due to the aforementioned 21% decrease in production, partially offset by a 16% increase in realized prices (including the effects of hedging) to $6.59 per Mcfe in the first nine months of 2005 from $5.71 per Mcfe in the same period in 2004.

Other revenues of $2.7 million in the first nine months of 2005 represent an indemnity payment received from our former stockholder related to the merger of $1.9 million and $0.8 million generated by our West Texas Aldwell unit gathering system.

Lease operating expenses increased 5% to $20.2 million in the first nine months of 2005 from $19.2 million in the first nine months of 2004. The increased costs were primarily attributable to the addition of new producing wells at our Aldwell Unit offset by reduced costs on our Black Widow, King Kong/Yosemite, and Pluto deep water fields. On a per unit basis, lease operating expenses were $0.90 per Mcfe in the first nine months of 2005 compared to $0.67 per Mcfe in the first nine months of 2004. The increased per unit costs also reflect lower production rates in the 2005 period, including hurricane-related disruptions.

Transportation expenses were $1.7 million or $0.08 per Mcfe in the first nine months of 2005, compared to $4.8 million or $0.17 per Mcfe in the first nine months of 2004. The reduction is primarily attributable to our deepwater fields and includes reductions caused by the filing of new and higher transportation allowances with the MMS on two of our deepwater fields for purpose of royalty calculation.

Depreciation, depletion, and amortization expense decreased 10% to $43.5 million during the first nine months of 2005 from $48.1 million for the first nine months of 2004 as a result of decreased production of 5.9 Bcfe in the first nine months of 2005 compared to the first nine months of 2004, partially offset by an increase in the unit-of-production depreciation, depletion and amortization rate to $1.93 per Mcfe for the first nine months of 2005 from $1.69 per Mcfe for the same period in 2004. The per unit increase was primarily the result of an increase in future development costs on our deepwater development fields.

General and administrative expenses (G&A), which are net of $3.1 million and $2.2 million of overhead reimbursements billed or received from other working interest owners in the first nine months of 2005 and 2004, respectively, increased 266% to $26.7 million during the first nine months of 2005 compared to $7.3 million in the first nine months of 2004. The increase was primarily due to recognizing $17.6 million in stock compensation expense related to restricted stock and options granted in the first nine months of 2005. We also paid $2.3 million to our former stockholders to terminate a services agreement in the first nine months of 2005, compared to $1.0 million under the same agreement in the first nine months of 2004. In addition, G&A expenses increased by $1.8 million due to a reduction in the amount of G&A capitalized in the first nine months of 2005 compared to the first nine months of 2004.

Net interest expense for the first nine months of 2005 increased 14% to $4.7 million from $4.1 million in the first nine months of 2004, primarily due to lower average debt levels in the first nine months of 2004 compared to the first nine months of 2005. In connection with the Merger on March 2, 2004, Mariner incurred $135 million in new bank debt and issued a $10 million promissory note to JEDI. For comparison purposes, approximately seven months of interest related to such borrowings is reflected in the first nine months of 2004 compared to nine months of interest in 2005.

Income before income taxes decreased to $54.0 million for the first nine months of 2005 compared to $77.8 million for the same period in 2004, attributable primarily to the decrease in oil and gas revenues resulting from the decreased production and increased G&A expenses, both as noted above. Offsetting these factors were the receipt of other income related to the indemnity payment and lower DD&A and transportation expenses.

Provision for income taxes decreased to $18.4 million for the first nine months of 2005 from $27.3 million for the first nine months of 2004 as a result of decreased operating income for the nine months ended September 30, 2005 compared to the prior period.

Year Ended December 31, 2004 compared to Year Ended December 31, 2003

Operating and Financial Results for the Year Ended December 31, 2004 Compared to the Year Ended December 31, 2003

Summary Operating Information:	Year Ended December 31, 2003	Non-GAAP Combined Year Ended December 31, 2004	Post-Merger Period from March 3, 2004 through December 31, 2004	Pre-Merger Period from January 1, 2004 through March 2, 2004
	(in thousands, except average sales price)			
Net production:				
Oil (MBbls)	1,600	2,298	1,885	413
Natural gas (MMcf)	23,772	23,782	19,549	4,233
Total (Mmcfe)	33,374	37,569	30,856	6,713
Average daily production (Mmcfe/d)	91	103	101	112
Hedging activities:				
Oil revenues (loss)	$ (4,969)	$ (12,299)	$ (11,613)	$ (686)
Gas revenues (loss)	(24,494)	(7,498)	(8,929)	1,431
Total hedging revenues (loss)	$ (29,463)	$ (19,797)	$ (20,542)	$ 745
Average Sales Prices:				
Oil (per Bbl) realized(1)	$ 23.74	$ 33.17	$ 33.69	$ 30.75
Oil (per Bbl) unhedged	26.85	38.52	39.85	32.41
Natural gas (per Mcf) realized(1)	4.40	5.80	5.67	6.39
Natural gas (per Mcf) unhedged	5.43	6.12	6.13	6.05
Total natural gas equivalent ($/Mcfe) realized(1)	4.27	5.70	5.65	5.92
Total natural gas equivalent ($/Mcfe) unhedged	5.15	6.23	6.32	5.81

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Summary Operating Information:	Non-GAAP Combined Year Ended December 31, 2003	2004	Post-Merger Period from March 3, 2004 through December 31, 2004	Pre-Merger Period from January 1, 2004 through March 2, 2004
	(in thousands, except average sales price)			
Oil and gas revenues:				
Oil sales	$ 37,992	$ 76,207	$ 63,498	$ 12,709
Gas sales	104,551	137,980	110,925	27,055
Total oil and gas revenues	$ 142,543	$ 214,187	$ 174,423	$ 39,764
Lease operating expenses	24,719	25,484	21,363	4,121
Transportation expenses	6,252	3,029	1,959	1,070
Depreciation, depletion and amortization	48,339	64,911	54,281	10,630
General and administrative expenses	8,098	8,772	7,641	1,131
Impairment of production equipment held for use		957	957	
Net interest expense (income)	6,225	5,734	5,820	(86)
Income before taxes and change in accounting method	45,688	105,300	82,402	22,898
Provision for income taxes	9,387	36,855	28,783	8,072

(1) Average realized prices include the effects of hedges.

Net production during 2004 increased to 37.6 Bcfe from 33.4 Bcfe during 2003 primarily due to the commencement of production on our Roaring Fork and Ochre projects, offset by normal production declines on existing fields.

Hedging activities in 2004 decreased our average realized natural gas price received by $0.32 per Mcf and revenues by $7.5 million, compared with a decrease of $1.03 per Mcf and revenues of $24.5 million for 2003. Our hedging activities with respect to crude oil during 2004 decreased the average sales price received by $5.35 per bbl and revenues by $12.3 million compared with a decrease of $3.11 per bbl and revenues of $5.0 million for 2003.

Oil and gas revenues increased 50% to $214.2 million during 2004 when compared to 2003 oil and gas revenues of $142.5 million, due to a 13% increase in production and a 33% increase in realized prices (including the effects of hedging) to $5.70 per Mcfe in 2004 from $4.27 per Mcfe in 2003.

Lease operating expenses increased 3% to $25.5 million in 2004 from $24.7 million in 2003 due to increased activity in our West Texas Aldwell project, partially offset by lower compression costs on our King Kong and Yosemite projects and the shut-in of our Pluto project for a large portion of 2004 pending the drilling and completion of the Mississippi Canyon 674 No. 3 well, which has been drilled and awaits installation of flowlines and related facilities.

Transportation expenses were $3.0 million for 2004, compared to $6.3 million for 2003. In the fourth quarter of 2004, we filed new transportation allowances with the MMS for purpose of royalty calculation. This resulted in a

$3.2 million decrease in transportation expense in 2004 compared to 2003. In addition, transportation expense from our new Roaring Fork field was offset by declines from our existing fields.

Depreciation, depletion, and amortization expense increased 34% to $64.9 million during 2004 from $48.3 million for 2003 as a result of an increase in the unit-of-production depreciation, depletion and amortization rate to $1.73 per Mcfe from $1.45 per Mcfe for the comparable period and a production increase of 4.2 Bcfe in 2004 compared to 2003. The per unit increase is primarily attributable to non-cash purchase accounting adjustments resulting from the merger.

G&A, which is net of $4.4 million of overhead reimbursements received from other working interest owners, increased 8% to $8.8 million during 2004 compared to $8.1 million in 2003 primarily due to increased compensation costs paid in connection with the merger and payments made pursuant to services contracts with affiliates of our sole stockholder, offset by increased overhead recoveries from our partners and amounts capitalized.

Impairment of production equipment held for use reflects the reduction of the carrying cost of our inventory as of December 31, 2004 by $1.0 million to account for a reduction in estimated value primarily related to subsea trees held in inventory.

Net interest expense for 2004 decreased 8% to $5.7 million from $6.2 million for 2003, primarily due to the repayment of our senior subordinated notes in August 2003, replaced by lower-cost bank debt in March 2004.

Income before income taxes and change in accounting method increased to $105.3 million for 2004 compared to $45.7 million in 2003, attributable primarily to the increase in oil and gas revenues resulting from the increased production and realized prices noted above.

Provision for income taxes increased to $36.9 million for 2004 from $9.4 million for 2003 as a result of increased current year operating income.

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

Net production decreased during 2003 to 33.4 Bcfe from 39.8 Bcfe in 2002. Production from new drilling in our onshore Aldwell project and offshore Roaring Fork and Vermilion 143 projects was offset by production declines in other fields and loss of production from our offshore Pluto project during the first seven months of 2003 as a result of a flowline mechanical problem that required extended maintenance.

Hedging activities in 2003 decreased our average realized natural gas price received by $1.03 per Mcf and revenues by $24.5 million, compared with an increase of $0.68 per Mcf and revenues of $20.3 million in 2002. Our hedging activities with respect to crude oil during 2003 decreased the average sales price received by $3.11 per bbl and revenues by $5.0 million compared with an increase of $1.25 per bbl and revenues of $2.1 million in 2002.

Oil and gas revenues decreased 10% to $142.5 million in 2003 from $158.2 million in 2002 (including the effects of hedge gains and losses), due to a 16% decrease in production offset by an 8% increase in average realized prices to $4.27 per Mcfe in 2003 from $3.97 per Mcfe in 2002 including the effects of hedging gains and losses.

Lease operating expenses decreased 5% to $24.7 million in 2003 from $26.1 million in 2002 due to the reduced chemical requirements at our King Kong and Yosemite projects offset by higher chemical costs at our Pluto field.

Transportation expenses decreased 40% to $6.3 million for 2003 from $10.5 million for 2002. The decrease was primarily attributable to lower minimum fees required under the transportation agreement for our Pluto project.

Depreciation, depletion, and amortization expense decreased 32% to $48.3 million for 2003 from $70.8 million for 2002 as a result of the decrease in the unit-of-production depreciation, depletion and amortization rate to $1.45 per Mcfe from $1.78 per Mcfe and 6.4 Bcfe of less production in 2003 compared to 2002. The primary driver behind the reduced DD&A rate per Mcfe was the reduction of our full cost pool and concurrent reduction of proved reserves by the proceeds from the sale of an interest in the Falcon and Harrier properties in 2003.

Early derivative settlements of non hedge designated instruments resulted in a loss of $3.2 million in 2003. There were no similar transactions in 2002.

G&A, which is net of $1.8 million of overhead reimbursements received from other working interest owners, increased 5% to $8.1 million for 2003 from $7.7 million for 2002. The increase was comprised of an 11% reduction in gross G&A (before capitalized items and overhead recoveries) driven primarily by reduced professional service costs and office rent, offset by higher employee compensation costs, which included retention payments. The reduction in gross G&A was offset by reduced overhead recoveries and capitalized items compared to 2002.

Net interest expense for 2003 decreased 37% to $6.2 million from $9.9 million for 2002, primarily due to mid-year retirement of our senior subordinated notes.

Income before income taxes and change in accounting method increased to a net income of $45.7 million for 2003 from $30.0 million in 2002, primarily as a result of 30% higher operating income (primarily driven by lower DD&A partially offset by lower oil and gas revenues) all as described more fully above.

Provision for income taxes increased to $9.4 million in 2003 as a result of Mariner utilizing all of its net operating losses. The provision for income taxes in 2002 was $0.

Liquidity and Capital Resources

Cash Flows and Liquidity

Working capital at September 30, 2005 was negative $30.2 million, excluding current derivative liabilities and related tax effects. Accounts payable and accrued liabilities at September 30, 2005 increased by approximately 23% over levels at December 31, 2004 primarily due to increased current obligations for our Swordfish and Pluto development projects at quarter end. As of December 31, 2004, we had negative working capital of approximately $18.7 million compared to positive working capital of $38.3 million at December 31, 2003, in each case excluding current derivative liabilities and restricted cash. The reduction in working capital from the prior year is primarily the result of a change in the manner Mariner utilizes excess cash. At year-end 2003, Mariner operated with no debt and consequently accumulated cash (approximately $60 million at year-end 2003) generated by operations and asset sales in order to fund future obligations and business activities. In March 2004, Mariner entered into a revolving credit facility, and since then has utilized excess cash to pay down outstanding advances to maintain debt levels as low as possible. In addition, our accounts payable and accrued liabilities at December 31, 2004 increased by about 32% over levels at December 31, 2003 primarily as a result of funding for development of our deepwater projects in progress at year end.

Our 2004 capital expenditures were $148.9 million. Approximately 60% of our capital expenditures were incurred for development projects, 32% for exploration activities and the remainder for acquisitions and other items (primarily capitalized overhead and interest).

We anticipate that our capital expenditures for 2005 will approximate $250 million with approximately 48% allocated to development projects, 27% to exploration activities, 21% to acquisitions and the remainder to other items (primarily capitalized overhead and interest). This is an increase of approximately $98 million over our original 2005 budget. The increase is primarily driven by acquisitions of interests in properties, by new drilling projects at LaSalle/NW Nansen, and by the cost of remediating a flow line obstruction at our Pluto project.

With the anticipated increase in capital expenditures and reduced production, partially from the impact of hurricanes, cash flows generated by operations for 2005 will not be sufficient to fund our 2005 capital expenditures. Any requirements for funding that exceed our cash flows will be funded through additional borrowings under our existing revolving credit facility. We currently have a borrowing base of $185 million with approximately $75 million drawn as of September 30, 2005. Because of increased capital expenditures in the fourth quarter of 2005 (including about $40 million for acquisitions) and reduced cash flows, borrowings under the revolving credit facility increased to approximately $152.0 million by year-end 2005.

However, the timing of expenditures (especially regarding deepwater projects) is unpredictable. Also, our cash flows are heavily dependent on the oil and natural gas commodity markets and our ability to hedge oil and natural gas prices is limited by our revolving credit facility to no more than 80% of our expected production from proved developed producing reserves. If either oil or natural gas commodity prices decrease from their current levels, our ability to finance our planned capital expenditures could be affected negatively. Furthermore, amounts available for borrowing under our revolving credit facility are largely dependent on our level of proved reserves and current oil and natural gas prices. If either our proved reserves or commodity prices decrease, amounts available to us to borrow under our revolving credit facility could be negatively affected. If our cash flows are less than anticipated or amounts available for borrowing under our revolving credit facility are reduced, we may be forced to defer planned capital expenditures.

In addition, our future oil and natural gas production depends on our success in finding or acquiring additional reserves. If we fail to replace reserves through drilling or acquisitions, our cash flows will be affected adversely. In general, production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves decline as reserves are produced unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both. Our ability to make the necessary capital investment to maintain or expand our asset base of oil and natural gas reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves.

Our existing proved reserves are comprised of West Texas and Gulf of Mexico properties. The West Texas properties are relatively long-life in nature characterized by relatively low decline rates (lower productive rates) while the Gulf of Mexico properties are shorter-life in nature characterized by relatively high decline rates (higher productive rates). For the nine months ended September 30, 2005, our Gulf of Mexico properties comprised about 79% of our total production. We plan to maintain an active drilling program on our onshore properties with the intention of maintaining or increasing production in those areas. Although production from our existing offshore wells will decline more rapidly over time than our onshore wells, the percentage of production attributable to our offshore wells is expected to increase in the coming years as more of our undeveloped deep water projects commence production. While we expect this trend to continue for the near future, oil and gas production (especially for our offshore properties) can be heavily affected by reservoir characteristics and unforeseen events (such as hurricanes and other casualties), so we can not predict with any certainty the timing of declines in production or the commencement of production from new projects.

In conjunction with the March 2004 merger, we established a new credit facility maturing on March 2, 2007. The new credit facility was fully drawn at inception for $135 million. See Credit Facility. In addition, we issued a $10 million promissory note to JEDI as part of the merger consideration. See Business Enron Related Matters and JEDI Term Promissory Note. This note matures in March 2006. Net proceeds from a private equity placement were approximately $45 million, of which $6 million was used to pay down the JEDI promissory note with the remainder used to pay down the credit facility.

For the year ended December 31, 2004 and the nine months ended September 30, 2005, our interest rate sensitivity for a change in interest rates of $^{1}/8$ percent on average outstanding debt under our credit facility is approximately $0.2 million and $0.1 million, respectively. The LIBOR rate on which our bank borrowings are primarily based was 4.19% as of November 23, 2005.

We had a net cash outflow of $57.6 million in 2004, compared to a net cash inflow of $41.8 million in 2003 and a net cash inflow of $6.5 million in 2002. A discussion of the major components of cash flows for these periods follows.

	Combined	Post-Merger	Pre-Merger		
				Year Ended December 31,	
	Year Ended December 31, 2004	Period from March 3, 2004 to December 31, 2004	Period from January 1, 2004 to March 2, 2004	2003	2002
	(in millions)				
Cash flows provided by operating activities	$ 156.2	$ 135.9	$ 20.3	$ 103.5	$ 60.3

Cash flows provided by operating activities in 2004 increased by $52.7 million compared to 2003 primarily due to improved operating results and net income driven by increased production volumes and higher net oil and natural gas prices realized by Mariner.

	Combined	Post-Merger	Pre-Merger		
				Year Ended December 31,	
	Year Ended December 31, 2004	Period from March 3, 2004 to December 31, 2004	Period from January 1, 2004 to March 2, 2004	2003	2002
	(in millions)				
Cash flows used in (provided by) investing activities	$ 148.9	$ 133.6	$ 15.3	$ (38.3)	$ 53.8

Cash flows used in investing activities in 2004 increased by $187.2 million compared to 2003 due to increased capital expenditures in 2004 and the sale of assets in prior years.

	Combined	Post-Merger	Pre-Merger		
				Year Ended December 31,	
	Year Ended	Period from March 3, 2004 to	Period from January 1, 2004 to	2003	2002

	December 31, 2004	December 31, 2004	March 2, 2004	
			(in millions)	
Cash flows used in financing activities	$ (64.9)	$ (64.9)		$ (100.0)

Cash flows used in financing activities in 2004 decreased by $35.1 million compared to 2003 as a result of a $166 million dividend to our former indirect parent used to help repay a term loan to an affiliate of Enron Corp. and the placement of our revolving credit facility.

Commodity Prices and Related Hedging Activities

The energy markets have historically been very volatile, and there can be no assurance that oil and gas prices will not be subject to wide fluctuations in the future. In an effort to reduce the effects of the volatility of the price of oil and natural gas on our operations, management has adopted a policy of hedging oil and natural gas prices from time to time primarily through the use of commodity price swap agreements and costless collar arrangements. While the use of these hedging arrangements limits the downside risk of adverse price movements, it also limits future gains from favorable movements.

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As of September 30, 2005, Mariner had the following hedge contracts outstanding:

Fixed Price Swaps	Quantity	Fixed Price	September 30, 2005 Fair Value Gain/(Loss)
			(in millions)
Crude Oil (Bbls)			
October 1 December 31, 2005	138,000	$ 25.22	$ (5.7)
January 1 December 31, 2006	140,160	29.56	(5.2)
Natural Gas (MMBtus)			
October 1 December 31, 2005	1,352,400	5.00	(12.3)
January 1 December 31, 2006	1,827,547	5.53	(13.6)
Total			$ (36.8)

Costless Collars	Quantity	Floor	Cap	September 30, 2005 Fair Value Gain/(Loss)
				(in millions)
Crude Oil (Bbls)				
October 1 December 31, 2005	57,960	$ 35.60	$ 44.77	$ (1.2)
January 1 December 31, 2006	251,850	32.65	41.52	(6.2)
January 1 December 31, 2007	202,575	31.27	39.83	(4.8)
Natural Gas (MMBtus)				
October 1 December 31, 2005	2,189,600	6.01	8.02	(12.3)
January 1 December 31, 2006	7,347,450	5.78	7.85	(29.1)
January 1 December 31, 2007	5,310,750	5.49	7.22	(14.7)
Total				$ (68.3)

As of December 31, 2004, Mariner had the following hedge contracts outstanding:

Fixed Price Swaps	Quantity	Fixed Price	December 31, 2004 Fair Value Gain/(Loss)
			(in millions)
Crude Oil (Bbls)			
January 1 December 31, 2005	606,000	$ 26.15	$ (10.0)
January 1 December 31, 2006	140,160	29.56	(1.5)
Natural Gas (MMBtus)			

January 1 December 31, 2005	8,670,159	5.41		(7.0)
January 1 December 31, 2006	1,827,547	5.53		(1.9)
Total			$	(20.4)

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Costless Collars		Quantity	Floor	Cap	December 31, 2004 Fair Value Gain/(Loss) (in millions)
Crude Oil (Bbls)					
January 1	December 31, 2005	229,950	$ 35.60	$ 44.77	$ (0.4)
January 1	December 31, 2006	251,850	32.65	41.52	(0.7)
January 1	December 31, 2007	202,575	31.27	39.83	(0.6)
Natural Gas (MMBtus)					
January 1	December 31, 2005	2,847,000	5.73	7.80	0.4
January 1	December 31, 2006	3,514,950	5.37	7.35	(0.3)
January 1	December 31, 2007	1,806,750	5.08	6.26	(0.4)
Total					$ (2.0)

We have reviewed the financial strength of our hedge counterparties and believe our credit risk to be minimal. Under the terms of some of these transactions, from time to time we may be required to provide security in the form of cash or letters of credit to our counterparties. As of December 31, 2004 and September 30, 2005, we had no deposits for collateral.

The following table sets forth the results of third party hedging transactions during the periods indicated:

	Year Ended December 31, 2004	2003	2002
	(dollars in millions)		
Natural Gas			
Quantity settled (MMBtus)	18,823,063	25,520,000	
Increase (Decrease) in Natural Gas Sales	$ (10.8)	$ (27.1)	
Crude Oil			
Quantity settled (Mbbls)	1,554	730	353
Increase (Decrease) in Crude Oil Sales	$ (16.9)	$ (5.0)	$ (0.8)

In accordance with purchase price accounting implemented at the time of the merger of our former indirect parent on March 2, 2004, we recorded the mark-to-market liability of our hedge contracts at such date totaling $12.4 million as a liability on our balance sheet. See Critical Accounting Policies and Estimates Hedging Program. For the year ended December 31, 2004, $7.9 million of the $27.7 million of cash hedge losses relate to the liability recorded at the time of the merger.

Interest Rate Hedges

Borrowings under our revolving credit the facility, discussed below, mature on March 2, 2007, and bear interest at either a LIBOR-based rate or a prime-based rate, at our option, plus a specified margin. Both options expose us to risk of earnings loss due to changes in market rates. We have not entered into interest rate hedges that would mitigate such risk.

Credit Facility

We have a revolving credit facility which provides up to $200 million of revolving borrowing capacity, subject to a borrowing base limitation. We currently expect to replace this credit facility when the merger is completed. See Financing Arrangements Relating to the Spin-Off and the Merger beginning on page 138. The borrowing capacity is currently subject to a borrowing base of $185 million. The borrowing base is subject to redetermination by the lenders quarterly; provided however, if at least $10 million of unused availability exists, the borrowing base will be redetermined semi-annually. The borrowing base is based upon the evaluation by the lenders of our oil and gas reserves and other factors. Any increase in the borrowing base requires the consent of all lenders.

Borrowings under the facility bear interest, at our option, at a rate of (i) LIBOR plus 2.00% to 2.75% depending upon utilization, or (ii) the greater of (a) the Federal Funds Rate plus 0.50% or (b) the Reference Rate, plus 0.00% to 0.50% depending upon utilization.

Substantially all of our assets, other than the assets securing the term promissory note issued to JEDI, are pledged to secure the credit facility and obligations under hedging arrangements with members of our bank group. In addition, both of our subsidiaries, Mariner Energy Texas LP and Mariner LP LLC, have guaranteed our obligations under the credit facility. We must pay a commitment fee of 0.25% to 0.50% per year on the unused availability under the credit facility, depending upon utilization.

The credit facility contains various restrictive covenants and other usual and customary terms and conditions of a revolving credit facility, including limitations on the payment of cash dividends and other restricted payments, limitations on the incurrence of additional debt, prohibitions on the sale of assets, and requirements for hedging a portion of our oil and natural gas production. Financial covenants require us to, among other things:

- maintain a ratio, as of the last day of each fiscal quarter, of (a) current assets (excluding cash posted as collateral to secure hedging obligations) plus unused availability under the credit facility to (b) current liabilities (excluding the current portion of debt and current portion of hedge liabilities) of not less than 1.00 to 1.00;

- maintain a ratio, as of the last day of each fiscal quarter, of (a) EBITDA (earnings before interest, taxes, depreciation, amortization and depletion) to (b) the sum of interest expense and maintenance capital expenditures for such period and 20% (on an annualized basis) of outstanding advances, of not less than 1.20 to 1.00; and

- maintain a ratio, as of the last day of each fiscal quarter, of (a) total debt to (b) EBITDA of not greater than 1.75 to 1.00 prior to the issuance of bonds as described in the credit agreement and 3.00 to 1.00 thereafter.

The credit facility also contains customary events of default, including the occurrence of a change of control or default by us in the payment or performance of any other indebtedness equal to or exceeding $2.0 million.

As of September 30, 2005, $75.0 million was outstanding under the credit facility, and the weighted average interest rate was 5.84%. This debt matures on March 2, 2007. Because of increased capital expenditures in the fourth quarter of 2005 (including about $40 million for acquisitions) and reduced cash flows, borrowings under the revolving credit facility increased to approximately $152.0 million by year-end 2005.

Our management is considering a possible sale in a private placement of between $150 and $250 million in aggregate principal amount of notes. The notes would not be registered under the Securities Act or any state securities laws and may not be offered or sold in the United States absent registration or an applicable exemption from registration. We expect that the notes would be offered only to qualified institutional buyers under Rule 144A and non-U.S. persons under Regulation S. We anticipate that the net proceeds from the offering would be used to repay borrowings under our credit facility, and that the terms of the notes would be no more restrictive than the terms of our credit facility.

JEDI Term Promissory Note

As part of the merger consideration payable to JEDI, we issued a term promissory note to JEDI in the amount of $10 million. The note matures on March 2, 2006, and bears interest, payable in kind at our option, at a rate of 10% per annum until March 2, 2005, and 12% per annum thereafter unless paid in cash in which event the rate remains 10% per annum. We have chosen to pay the interest in cash rather than in kind. The JEDI note is secured by a lien on three of our properties with no proved reserves located in the Gulf of Mexico. We can offset against the note the amount of certain claims for indemnification that can be asserted against JEDI under the terms of the merger agreement. The JEDI term promissory note contains customary events of default, including an event of default triggered by the occurrence of an event of default under our credit facility. We used $6 million of the proceeds from the recent private equity placement to repay a portion of the JEDI note. As of September 30, 2005, $4 million was still outstanding under the JEDI note.

Capital Expenditures and Capital Resources

The following table presents major components of our capital expenditures for each of the three years in the period ended December 31, 2004.

	Combined	Post-Merger	Pre-Merger		
	Year Ended December 31, 2004	Period from March 3, 2004 to December 31, 2004	Period from January 1, 2004 to March 2, 2004	Year Ended December 31, 2003	Year Ended December 31, 2002
	(in millions)				
Capital expenditures:					
Leasehold acquisition	$ 4.8	$ 4.4	$ 0.4	$ 4.8	$ 14.9
Oil and natural gas exploration	43.0	35.9	7.1	26.8	25.5
Oil and natural gas development	88.6	82.0	6.6	44.3	55.3
Proceeds from property conveyances				(121.6)	(52.3)
Acquisitions	4.9	4.9			
Other items (primarily capitalized overhead and interest)	7.6	6.4	1.2	7.4	10.4
Total capital expenditures, net of proceeds from property conveyances	$ 148.9	$ 133.6	$ 15.3	$ (38.3)	$ 53.8

Our net capital expenditures for 2004 increased by $187.2 million, as compared to 2003, as a result of increased exploration and development expenditures with no offsetting proceeds from property conveyances in 2004.

Our net capital expenditures for 2003 decreased $92.1 million as compared to 2002 as a result of higher proceeds from property conveyances and overall lower capital expenditures as result of our shift to a more balanced portfolio among Gulf of Mexico deepwater and shelf and onshore properties.

We had no long-term debt outstanding as of December 31, 2003. As of December 31, 2004, long-term debt was $115 million. See Credit Facility.

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Contractual Commitments

We have numerous contractual commitments in the ordinary course of business, debt service requirements and operating lease commitments. The following table summarizes these commitments at December 31, 2004:

	Total	Less Than One Year	1-3 Years	3-5 Years	More Than 5 Years
			(in millions)		
Long-term debt obligations(1)	$ 115.0	$	$ 115.0	$	$
Interest obligations(2)	0.6	0.5	0.1		
Operating leases	1.1	0.6	0.5		
Abandonment liabilities	24.0	4.7	7.2	7.7	4.4
Derivative liability(3)	22.4	17.0	5.4		
Other long-term liabilities	3.0	2.0	1.0		
Total contractual cash commitments	$ 166.1	$ 24.8	$ 129.2	$ 7.7	$ 4.4

(1) As of December 31, 2004, we had incurred debt obligations under our credit facility and the JEDI promissory note that are due as follows: $10 million in 2006; and $105 million in 2007. However, we used a portion of the net proceeds of the private equity placement to repay a portion of amounts outstanding under our credit facility and $6 million under the JEDI promissory note. As of November 30, 2005, we had incurred debt obligations under our credit facility of $75 million and under the JEDI promissory note of $4 million.

(2) Interest obligations represent approximately 14 months of interest due on the JEDI promissory note at 10%. Future interest obligations under our credit facility are uncertain, due to the variable interest rate on fluctuating balances. Based on a 5.2% weighted average interest rate on amounts outstanding under our credit facility as of December 31, 2004, $5.5 million, $5.5 million and $0.9 million would be due under the credit facility in 2005, 2006 and 2007, respectively.

(3) As of September 30, 2005, the fair value of the derivative liabilities was $105.1 million, including $76.9 million due in less than one year.

MMS Appeal Mariner operates numerous properties in the Gulf of Mexico. Two of such properties were leased from the MMS subject to the Outer Continental Shelf Deep Water Royalty Relief Act (the RRA). The RRA relieved the obligation to pay royalties on certain predetermined leases until a designated volume is produced. These two leases contained language that limited royalty relief if commodity prices exceeded predetermined levels. For the years 2000, 2001, 2003 and 2004, commodity prices exceeded the predetermined levels. Management believes the MMS did not have the authority to set pricing limits, and Mariner filed an administrative appeal with the MMS and has withheld royalties regarding this matter. The MMS filed a motion to dismiss our appeal with the Department of the Interior s Board of Land Appeals. On April 6, 2005, the Board of Land Appeals granted the MMS motion and dismissed our appeal. On October 3, 2005, we filed suit in the U.S. District Court for the Southern District of Texas seeking judicial review of the dismissal of our appeal by the Board of Land Appeals. Mariner has recorded a liability for 100% of the exposure on this matter which on September 30, 2005 was $14.6 million. For additional information concerning the contested royalty payments and the MMS s demands, see Business Legal Proceedings below.

Off-Balance Sheet Arrangements

Transportation Contract In 1999, Mariner constructed a 29-mile flowline from a third party platform to the Mississippi Canyon 674 subsea well. After commissioning, MEGS LLC, an Enron affiliate, purchased the flowline from Mariner and its joint interest partner. In addition, Mariner entered into a firm transportation contract with MEGS LLC at a rate of $0.26 per MMBtu to transport Mariner s share of approximately 130,000,000 MMbtus of natural gas from the commencement of production through March 2009. Mariner s working interest in the well is 51%. For the year ended December 31, 2003, Mariner paid

$1.9 million on this contract. The remaining volume commitment was 14,707,107 MMbtus or $3.8 million net to Mariner. Pursuant to the contract, Mariner was required to deliver minimum quantities through the flowline or be subject to minimum monthly payment requirements.

On May 10, 2004, Mariner and the other 49% working interest owner in the Mississippi Canyon 674 well purchased the flowline from MEGS LLC for an adjusted purchase price of approximately $3.8 million, of which approximately $1.9 million was paid by Mariner, and terminated the transportation contract and associated liability. Accordingly, we currently have no off-balance sheet arrangements.

Recent Accounting Pronouncements

On December 16, 2004, the FASB issued FASB Statement No. 123 (revised 2004), *Share-Based Payment,* (FASB No. 123(R)) that addresses the accounting for share-based payment transactions (for example, stock options and awards of restricted stock) in which an employer receives employee-services in exchange for equity securities of Mariner or liabilities that are based on the fair value of Mariner s equity securities. The new standard replaces FASB Statement No. 123, *Accounting for Stock-Based Compensation (FASB No. 123)* and supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees,* and generally requires such transactions be accounted for using a fair-value-based method that recognizes compensation expense rather than the optional pro forma disclosure allowed under FASB No. 123. Mariner adopted the provisions of the new standard on January 1, 2005.

As a result of the adoption of the above described SFAS No. 123(R), we recorded compensation expense for the fair value of restricted stock that was granted pursuant to our Equity Participation Plan (see Management of Mariner Equity Participation Plan) and for subsequent grants of stock options or restricted stock made pursuant to the Mariner Energy, Inc. Stock Incentive Plan (see Management of Mariner Stock Incentive Plan). We recorded compensation expense for the restricted stock grants equal to their fair value at the time of the grant, amortized pro rata over the restricted period. General and administrative expense for the nine months ended September 30, 2005 includes $17.2 million of compensation expense related to restricted stock granted in 2005 and $0.4 million of compensation expense related to stock options outstanding as of September 30, 2005.

On September 2, 2004, the FASB issued FASB Staff Position No. FAS 142-2, *Application of FASB Statement No. 142, Goodwill and Other Intangible Assets, to Oil and Gas Producing Entities,* addressing whether the scope exception within SFAS No. 142, *Goodwill and Other Intangible Assets* includes the balance sheet classification and disclosures for drilling and mineral rights of oil and gas producing properties. The FASB staff concluded that the accounting framework for oil and gas entities is based on the level of established reserves, not whether an asset is tangible or intangible, and thus the scope exception extended to the balance sheet classification and disclosure provisions for such assets.

On September 28, 2004, the SEC released Staff Accounting Bulletin (SAB) 106 regarding the application of SFAS 143, Accounting for Asset Retirement Obligations (AROs), by oil and gas producing companies following the full cost accounting method. Pursuant to SAB 106, oil and gas producing companies that have adopted SFAS 143 should exclude the future cash outflows associated with settling AROs (ARO liabilities) from the computation of the present value of estimated future net revenues for the purposes of the full cost ceiling calculation. In addition, estimated dismantlement and abandonment costs, net of estimated salvage values, that have been capitalized (ARO assets) should be included in the amortization base for computing depreciation, depletion and amortization expense. Disclosures are required to include discussion of how a company s ceiling test and depreciation, depletion and amortization calculations are impacted by the adoption of SFAS 143. SAB 106 is effective prospectively as of the beginning of the first fiscal quarter beginning after October 4, 2004. Since our adoption of SFAS 143 on January 1, 2003, we have calculated the ceiling test and our depreciation, depletion and amortization expense in accordance with the interpretations set forth in SAB 106; therefore, the adoption SAB 106 had no effect on our financial statements.

On December 16, 2004, the FASB issued Statement 153, Exchanges of Nonmonetary Assets, an amendment of APB Opinion No. 29, to clarify the accounting for nonmonetary exchanges of similar productive assets. SFAS 153 eliminates the exception from the fair value measurement for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. The statement will be applied prospectively and is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. We do not have any nonmonetary transactions for any period presented to which this statement would apply. We do not expect the adoption of SFAS 153 to have a material impact on our financial statements.

Quantitative and Qualitative Disclosures About Market Risk.

For a discussion of our market risk, See Liquidity and Capital Resources Commodity Prices and Related Hedging Activities.

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BUSINESS

We are an independent oil and gas exploration, development and production company with principal operations in the Gulf of Mexico and the Permian Basin in West Texas. As of December 31, 2004, we had 237.5 Bcfe of estimated proved reserves, of which approximately 64% were natural gas and 36% were oil and condensate. The estimated pre-tax PV10 value of our estimated proved reserves as of December 31, 2004 was approximately $668 million, and the standardized measure of discounted future net cash flows attributable to our estimated proved reserves was approximately $494.4 million. Please see Estimated Proved Reserves for a definition of PV10 and a reconciliation of PV10 to the standardized measure of discounted future net cash flows. As of December 31, 2004, approximately 46% of our estimated proved reserves were classified as proved developed. For the year ended December 31, 2004, our total net production was 37.6 Bcfe. Our estimated proved reserve base is balanced, with 48% of the reserves located in the Permian Basin of West Texas, 37% in the Gulf of Mexico deepwater and 15% on the Gulf of Mexico shelf as of December 31, 2004.

The distribution of our proved reserves reflects our efforts over the last three years to diversify our asset base, which in prior years had been focused primarily in the Gulf of Mexico deepwater. We have shifted some of our focus on deepwater activities to increased exploration and development on the Gulf of Mexico shelf and exploitation of our West Texas Permian Basin properties. By allocating our resources among these three areas, we expect to balance the risks associated with the exploration and development of our asset base. We intend to continue to pursue moderate-risk exploratory and development drilling projects in the Gulf of Mexico deepwater and on the Gulf of Mexico shelf, including select deep shelf prospects, and also target low-risk infill drilling projects in West Texas. It is our practice to generate most of our prospects internally, but from time to time we also acquire third-party generated prospects. We then drill to find oil and natural gas reserves, a process that we refer to as growth through the drill bit.

The following discussion includes statements that may be deemed forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. See Cautionary Statement Concerning Forward-Looking Statements for more details. Also, the discussion uses terms that pertain to the oil and gas industry, and you should see Glossary of Oil and Natural Gas Terms for the definition of certain terms.

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Significant Properties

We own oil and gas properties, producing and non-producing, onshore in Texas and offshore in the Gulf of Mexico, primarily in federal waters. Our largest properties, based on the present value of estimated future net proved reserves as of December 31, 2004, are shown in the following table.

	Operator	Mariner Working Interest	Approximate Water Depth (Feet)	Gross Producing Wells(1)	Date Production Commenced/ Expected	Estimated Proved Reserves (Bcfe)	PV10 Value (In $ Millions)(2)	Standardized Measure (In $ Millions)
		%						
West Texas Permian Basin:								
Aldwell Unit	Mariner	66.5(3)	Onshore	185	1949	112.7	$ 203.8	
Gulf of Mexico Deepwater:								
Mississippi Canyon 296/252 (Rigel)	Dominion	22.5	5,200	0	Second Quarter 2006	22.4	82.9	
Viosca Knoll 917/961/962 (Swordfish)	Mariner(4)	15.0	4,700	2	Fourth Quarter 2005	13.4	59.3	
Green Canyon 516 (Yosemite)	ENI	44.0	3,900	1	2002	15.1	66.6	
Mississippi Canyon 718 (Pluto)(5)	Mariner	51.0	2,830	0	1999	9.0	31.7	
Green Canyon 178 (Baccarat)	W&T	40.0	1,400	0	Third Quarter 2005	4.0	14.3	
Green Canyon 472/473 (King Kong)	ENI	50.0	3,850	0	2002	1.2	2.0	
Gulf of Mexico Shelf:								
Mississippi Canyon 66 (Ochre)(6)	Mariner	75.0	1,150	0	2004	3.6	11.7	
Other Properties				43		56.1	195.7	
Total:				231		237.5	$ 668.0	$ 494.4

(1) Wells producing or capable of producing as of December 31, 2004.

(2) Please see Estimated Proved Reserves for a definition of PV10 and a reconciliation of PV10 to the standardized measure of discounted future net cash flows.

(3) We operate the field and own working interests in individual wells ranging from approximately 33% to 84%.

(4) Mariner served as operator until December 2005, at which time pursuant to certain contractual arrangements, Noble Energy, Inc., a 60% partner in the project, began serving as operator.

(5) This field was shut-in in April 2004 pending the drilling of a new well and installation of an extension to the existing infield flowline and umbilical. As a result, as of December 31, 2004, 9.0 Bcfe of our net proved reserves attributable to this project were classified as proved undeveloped reserves. We expect production from Pluto to recommence in the second quarter of 2006.

(6) Field has been shut in since September 2004 due to destruction of host platform by Hurricane Ivan.

West Texas Permian Basin

Aldwell Unit. We operate and own working interests in individual wells ranging from 33% to 84% (with an average working interest of approximately 66.5%), in the 18,500-acre Aldwell Unit. The field is located in the heart of the Spraberry geologic trend southeast of Midland, Texas, and has produced oil and gas since 1949. We began our recent redevelopment of the Aldwell Unit by drilling eight wells in the fourth quarter of 2002, 43 wells in 2003, and 54 wells in 2004. As of December 31, 2004, there were a total of 185 wells producing or capable of producing in the field. Our aggregate net capital expenditures for

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the 2004 drilling program in the field were approximately $20.3 million, and we added 27 Bcfe of proved reserves, while producing 4.0 Bcfe.

During 2005, we have accelerated our development program in West Texas. Through September 30, 2005, we had drilled 65 new wells at our Aldwell and North Stiles Units. All of our drilling in the Aldwell and North Stiles Units has resulted in commercially successful wells that are expected to produce in quantities sufficient to exceed costs of drilling and completion.

We have completed construction of our own oil and gas gathering system and compression facilities in the Aldwell Unit. We began flowing gas production through the new facilities on June 1, 2005. We have also entered into new contracts with third parties to provide processing of our natural gas and transportation of our oil produced in the unit. The new gas arrangement also provides us with the option to sell our gas to one of four firm or five interruptible sales pipelines versus a single outlet under the former arrangement. We expect these arrangements to improve the economics of production from the Aldwell Unit.

In December 2004, we acquired an approximate 45% working interest in two Permian Basin fields containing over 4,000 acres. We believe the fields contain more than twenty 80-acre infill drilling locations and that either or both may also have 40-acre infill drilling opportunities. We have commenced drilling operations in one of the fields. In February 2005, we acquired five producing wells located in Howard County, Texas, approximately 50 miles north of our Aldwell Unit. The purchase price was $3.5 million, subject to post-closing adjustments.

In August 2005, but effective in October 2005, we entered into an agreement covering approximately 33,000 acres in West Texas, pursuant to which, upon closing, we acquired an approximate 35% working interest in approximately 200 existing producing wells effective November 1, 2005, and committed to drill an additional 150 wells within a four year period, funding $36.5 million of our partner s share of drilling costs for such 150-well drilling program. We will obtain an assignment of an approximate 35% working interest in the entire committed acreage upon completion of the 150-well program.

Gulf of Mexico Deepwater

Mississippi Canyon 296 (Rigel). Mariner generated the Rigel prospect and acquired its interest in Mississippi Canyon block 296 at a federal offshore Gulf lease sale in March 1999. Pursuant to an agreement with third parties, in September 1999 we cross-assigned leasehold interests in Mississippi Canyon blocks 208, 252 and 296 with the result that our working interest in all three blocks is now 22.5%. The project is located approximately 130 miles southeast of New Orleans, Louisiana, in water depth of approximately 5,200 feet. A successful exploration well was drilled on the prospect in 1999. In September 2003, a successful appraisal well was drilled. This project is currently under development with a single subsea well and a planned 12-mile subsea tie back to an existing subsea manifold that is connected to an existing platform. We expect production to begin in the second quarter of 2006.

Viosca Knoll 917/961/962 (Swordfish). Mariner generated the Swordfish prospect and entered into a farm-out agreement with BP in September 2001. We operated Swordfish until December 2005 and own a 15% working interest in this project, which is located in the deepwater Gulf of Mexico 105 miles southeast of New Orleans, Louisiana, in a water depth of approximately 4,700 feet. In November and December of 2001, we drilled two successful exploration wells on blocks 917 and 962. In August 2004, a successful appraisal well found additional reserves on block 961. All wells have been completed. Due to the impact of Hurricane Katrina on the host facility, initial production was delayed until the fourth quarter of 2005.

Green Canyon 516 (Yosemite). Mariner generated the Yosemite prospect and acquired the prospect at a Gulf of Mexico federal lease sale in 1998. We have a 44% working interest in this project, located in approximately 3,900 feet of water, approximately 150 miles southeast of New Orleans. In 2001, we drilled an exploratory well on the prospect, and in February 2002, we commenced production via a joint King Kong/ Yosemite 16 mile subsea tieback to an existing platform.

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Mississippi Canyon 718 (Pluto). Mariner initially acquired an interest in this project in 1997, two years after gas was discovered on the project. We operate the property and own a 51% working interest in the project and the 29-mile flowline that connects to a third-party production platform. We developed the field with a single subsea well which is located in the Gulf of Mexico approximately 150 miles southeast of New Orleans, Louisiana, at a water depth of approximately 2,830 feet. The field was shut-in in April 2004 pending the drilling of a new well and completion of the installation of an extension to the existing infield flowline and umbilical. Installation of the subsea facilities is now complete. During start up operations, a paraffin plug was discovered in the flow line between the Pluto field and the host facility. Remediation efforts are in progress and nearing completion. Production is expected to recommence in the second quarter of 2006, following completion of repairs to the host facilities necessitated by damage inflicted by Hurricane Katrina.

Green Canyon 178 (Baccarat). Mariner generated the Baccarat prospect and acquired a 100% working interest in Green Canyon block 178 at a Gulf of Mexico federal offshore lease sale in July 2003. The project is located in approximately 1,400 feet of water approximately 145 miles southwest of New Orleans, Louisiana. Subsequent to the acquisition, Mariner entered into a farmout agreement, retaining a 40% working interest in the project. A successful exploration well was drilled in May 2004. The project is under development as a subsea tieback to an existing host platform and was brought online in the third quarter of 2005. The host platform sustained damage during Hurricane Rita, resulting in production being shut-in. Production recommenced in January 2006.

Green Canyon 472/473 (King Kong). In July 2000, Mariner acquired a 50% working interest in the King Kong Gulf of Mexico project. The project is located in approximately 3,850 feet of water, approximately 150 miles southeast of New Orleans. Mariner completed the project as a joint King Kong/ Yosemite 16 mile subsea tieback to an existing platform. Production began in February 2002.

Other Prospects and Activity

In late 2004, we participated in a successful exploratory well in our North Black Widow prospect in Ewing Banks 921, which is located approximately 125 miles south of New Orleans in approximately 1,700 feet of water. We have a 35% working interest in this project. A development plan for the North Black Widow prospect has been approved and the operator of this project currently anticipates production from this project to begin in the second quarter of 2006. At June 30, 2005 approximately 4.5 Bcfe of estimated proved reserves have been assigned net to Mariner s interest.

In May 2005, we acquired an additional 18.75% working interest in the Bass Lite project for approximately $5.0 million, bringing our total working interest to 38.75%. The Bass Lite project is located in Atwater Valley blocks 380, 381, 382, 425 and 426, approximately 200 miles southeast of New Orleans in approximately 6,500 feet of water. We were elected operator of this project, subject to MMS approval, and negotiations continue with third party host facilities and partners to establish firm development plans. At June 30, 2005 approximately 30.7 Bcfe of estimated proved reserves have been assigned net to Mariner s interest.

In June 2005, we increased our working interest in the LaSalle project (East Breaks 558, 513, and 514) to 100% by acquiring the remaining working interest owned by a third party for $1.5 million. The blocks contain an undeveloped discovery, as well as exploration potential. As of December 31, 2004, we have booked no proved reserves to this project. We have recently executed a participation agreement with Kerr McGee to jointly develop the LaSalle project and Kerr McGee s nearby NW Nansen exploitation project (East Breaks 602). Under the proposed participation agreement, Mariner owns a 33% working interest in the NW Nansen project and a 50% working interest in the LaSalle project. The LaSalle and NW Nansen projects are located approximately 150 miles south of Galveston, Texas in water depths of approximately 3,100 and 3,300 feet, respectively. The development of these projects may require the drilling of up to four wells in 2005 and 2006 and related completion and facility capital in 2006.

At the King Kong/ Yosemite field (Green Canyon blocks 516, 472, and 473) we have planned, in conjunction with the operator, a two well drilling program to exploit potential new reserve additions. We anticipate drilling one development well and one exploration well the first on block 473 and the second on block 472, both in the first quarter of 2006. We own a 50% working interest in blocks GC 472 and 473 and a 44% working interest in block 516.