MARINER ENERGY INC
Form 10-K
February 29, 2008

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

Form 10-K

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2007

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number 1-32747

MARINER ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	**86-0460233**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification Number)*

One BriarLake Plaza, Suite 2000
2000 West Sam Houston Parkway South
Houston, Texas 77042
(Address of principal executive offices and zip code)

(713) 954-5500

(Registrant s telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $.0001 par value	New York Stock Exchange

Securities registered pursuant to section 12(g) of the Act:

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes o No þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or smaller reporting company. See the definitions of large accelerated filer , accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

The aggregate market value of the registrant s common stock held by non-affiliates on June 30, 2007 was approximately $2,044,768,585 based on the closing sale price of $24.25 per share as reported by the New York Stock Exchange on June 29, 2007. The number of shares of common stock of the registrant issued and outstanding on February 20, 2008 was 87,237,800.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of registrant s Proxy Statement relating to the Annual Meeting of Stockholders to be held April 30, 2008 are incorporated by reference into Part III of this Form 10-K.

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Statement Regarding Computation of Ratio of Earnings to Fixed Charges
List of Subsidiaries
Consent of Deloitte & Touche LLP.
Consent of Ryder Scott Company, L.P.
Certification of CEO Pursuant to Section 302
Certification of CFO Pursuant to Section 302
Certification of CEO Pursuant to Section 906
Certification of CFO Pursuant to Section 906

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Various statements in this annual report, including those that express a belief, expectation, or intention, as well as those that are not statements of historical fact, are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. 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 may, estimate, project, predict, believe, expect, anticipate, potential, plan, goal or other words that convey the uncertainty of futu outcomes. The forward-looking statements in this annual report speak only as of the date of this annual report; we disclaim any obligation to update these statements unless required by 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 described in Item 1A. Risk Factors and Item 7.

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Management s Discussion and Analysis of Financial Condition and Results of Operations elsewhere in this annual report. 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;
- risks arising out of our hedging transactions;
- marketing of oil and natural gas;
- competition in the oil and natural gas industry;
- the impact of weather and the occurrence of natural events and natural disasters such as loop currents, hurricanes, fires, floods and other natural events, catastrophic events and natural disasters;
- governmental regulation of the oil and natural gas industry;
- environmental liabilities;
- developments in oil-producing and natural gas-producing countries;
- uninsured or underinsured losses in our oil and natural gas operations;
- risks related to our level of indebtedness; and
- risks related to significant acquisitions or other strategic transactions, such as failure to realize expected benefits or objectives for future operations.

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PART I

The following discussion is intended to assist you in understanding our business and the results of our operations. It should be read in conjunction with the Consolidated Financial Statements and the related notes that appear elsewhere in this report. Certain statements made in our discussion may be forward looking. Forward-looking statements involve risks and uncertainties and a number of factors could cause actual results or outcomes to differ materially from our expectations. See Cautionary Statements at the beginning of this report on Form 10-K for additional discussion of some of these risks and uncertainties. Unless the context otherwise requires or indicates, references to Mariner, we, our, ours, and us refer to Mariner Energy, Inc. and its consolidated subsidiaries collectively. Cert and natural gas industry terms used in this annual report are defined in the Glossary of Oil and Natural Gas Terms set forth in Item 1. Business of this annual report.

Item 1. *Business.*

General

Mariner Energy, Inc. is an independent oil and gas exploration, development, and production company. We were incorporated in August 1983 as a Delaware corporation. Our corporate headquarters are located at One BriarLake Plaza, Suite 2000, 2000 West Sam Houston Parkway South, Houston, Texas 77042. Our telephone number is (713) 954-5500 and our website address is www.mariner-energy.com. Our common stock is listed on the New York Stock Exchange and trades under the symbol ME.

We currently operate in three principal geographic areas:

West Texas, where we are an active driller in the prolific Spraberry field in the Permian Basin at depths between 6,000 and 10,000 feet. Our increasing West Texas operation, which is characterized by long reserve life, stable drilling and production performance, and relatively lower capital requirements, somewhat counterbalances the higher geological risk, operational challenges and capital requirements attendant to most of our deepwater Gulf of Mexico operations. We are aggressively expanding our presence in the region, targeting a combination of infill drilling activities in established producing trends, including the Spraberry, Dean, Wolfcamp and Devonian/Fusselman trends, as well as exploration activities in emerging plays such as the Wolfberry and newer Wolfcamp trends.

Deepwater Gulf of Mexico, where we have actively conducted exploration and development projects since 1996 in water depths ranging from 1,300 feet up to 7,000 feet. Employing our experienced geoscientists, rich seismic database, and extensive subsea tieback expertise, we have participated in more than 75 deepwater wells. Our deepwater exploration operation targets larger potential reserve accumulations than are generally accessible onshore or on the Gulf of Mexico shelf.

Shelf of the Gulf of Mexico, where we drill or participate in conventional shelf wells and deep shelf wells extending to 1,300 foot water depths. We significantly increased our shelf operations and effectively doubled our size with our 2006 acquisition of the Gulf of Mexico operations of Forest Oil Corporation (Forest). See Note 3. Acquisitions and Dispositions in the Notes to the Consolidated Financial Statements in Part II, Item 8 of this Annual Report on Form 10-K for more information regarding this transaction. We currently pursue a two-pronged strategy on the shelf, combining opportunistic acquisitions of legacy producing fields believed to hold exploitation potential and active exploration activities targeting conventional and deep shelf opportunities. Given the highly mature nature of this area and the steep production declines characteristic of most wells in this region, the goal of our shallow water or shelf operation is to maximize cash flow for reinvestment in our deepwater and West Texas operations, as well as for expansion into new operating areas.

In 2007, we generated net income of $143.9 million on total revenues of $874.7 million. We produced approximately 100.3 Bcfe during 2007 and our average daily production rate was 275 MMcfe per day. Our average realized sales price per unit, including the effects of hedging, was $8.71/Mcfe for 2007. At December 31, 2007, we had 835.8 Bcfe of estimated proved reserves, of which approximately 54% were

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natural gas and 46% were oil, natural gas liquids (NGLs) and condensate. Approximately 67% of our estimated proved reserves were classified as proved developed.

We file annual, quarterly and current reports, proxy statements and other information as required by the Securities and Exchange Commission (SEC). Our SEC filings are available to the public over the Internet at the SEC s web site at www.sec.gov. or at the SEC s public reference room at 450 Fifth Street, N.W., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information about the public reference room. Reports and other information about Mariner can be inspected at the offices of the New York Stock Exchange, 20 Broad Street, New York, New York 10005. Copies of our SEC filings are available free of charge on our website at www.mariner-energy.com as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The information on our website is not a part of this annual report. Copies of our SEC filings can also be provided to you at no cost by writing or telephoning us at our corporate headquarters.

Recent Developments

West Texas Acquisition. On December 31, 2007, we acquired additional working interests in certain of our existing properties in the Spraberry field in the Permian Basin, increasing our average working interest across these properties to approximately 72%. A summary of the interests we acquired is:

- an approximate 56% working interest in approximately 32,000 gross acres in Reagan, Midland, Dawson, Glasscock, Martin and Upton Counties;
- interests in 348 (195 net) producing wells producing approximately 7.5 MMcfe per day net to the interests acquired; and
- Ryder Scott Company, L.P. estimated net proved oil and gas reserves attributable to the acquisition of approximately 95.5 Bcfe (75% oil and NGLs).

We anticipate operating substantially all of the assets. We financed the purchase price of approximately $122.5 million under our bank credit facility.

Gulf of Mexico Shelf Acquisition. On January 31, 2008, we acquired 100% of an indirect subsidiary of StatoilHydro ASA that owns substantially all of its former Gulf of Mexico shelf assets and operations. A summary of acquired assets and operations as of January 1, 2008 is:

- Mariner internally estimated proved oil and gas reserves of 52.4 Bcfe, 95% of which are developed;
- interests in 36 (16 net) producing wells producing approximately 53 MMcfe per day net to the subsidiary s interest, 76% of which we intend to operate;
- gas gathering systems comprised of 31 miles of 10-inch, 12-inch and 16-inch pipelines; and
- approximately 106,000 net acres of developed leasehold and 256,000 net acres of undeveloped leasehold.

We paid approximately $243 million in the transaction, subject to customary purchase price adjustments. We financed the transaction through borrowings under our bank credit facility.

Amendment of Bank Credit Facility. On January 31, 2008, we further amended our senior secured revolving credit facility to, among other things, increase the facility s maximum credit availability to $1 billion, subject to an increased borrowing base of $750 million as of that date, and to extend the facility s term to January 31, 2012. See Note 4. Long-Term Debt and Note 13. Subsequent Events in the Notes to the Consolidated Financial Statements in Part II, Item 8 of this Annual Report on Form 10-K for more information regarding the bank credit facility.

MMS Lease Sale 205. We are an active participant in Gulf of Mexico lease sales by the Minerals Management Service of the United States Department of the Interior (MMS). We were the apparent high bidder on a company-record 23 new blocks in MMS lease sale 205 in October 2007, of which 21 recently were awarded, representing at least 15 exploratory projects.

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Balanced Growth Strategy

We are a growth company and strive aggressively to increase our reserves and production from our existing asset base as well as through expansion into new operating areas. Our management team pursues a balanced growth strategy employing varying elements of exploration, development, and acquisition activities in complementary operating regions intended to achieve an overall moderate-risk growth profile at attractive rates of return under most industry conditions.

Exploration: Our exploration program is designed to facilitate organic growth through exploration in a wide variety of exploratory drilling projects, including higher-risk, high-impact projects that have the potential to create substantial value for our stockholders. We view exploration as a core competency. We typically dedicate a significant portion of our capital program each year to prospecting for new oil and gas fields, including in the deepwater Gulf of Mexico where reserve accumulations are typically much larger than those found onshore or on the shelf. Our explorationists have a distinguished track record in the Gulf of Mexico and have made several significant discoveries in the deepwater and shelf. Our reputation for generating high-quality exploration prospects also can create potentially valuable partnering opportunities, which can enable us to participate in exploration projects developed by other operators.

Development: Our development efforts are intended to complement our higher-risk exploration projects through a variety of moderate-risk activities targeted at maximizing recovery and production from known reservoirs as well as finding overlooked oil and gas accumulations in and around existing fields. Our geoscientists and engineers have a solid track record in effectively developing new fields, redeveloping legacy fields, rejuvenating production, controlling unit costs, and adding incremental reserves at attractive finding costs in both onshore and offshore fields. Our development and exploitation program strives to enhance the rate of returns of our projects, allow us to establish critical operating mass from which to expand in our focus areas, and generate a rich portfolio of relatively lower-risk engineering/exploitation projects that counterbalance our higher-risk exploration activities.

Acquisitions: In addition to our internal exploration and development activities on our existing properties, we also compete actively for new oil and gas properties through property acquisitions as well as corporate transactions. Our management team has substantial experience identifying and executing a wide variety of tactical and strategic transactions that augment our existing operations or present opportunities to expand into new operating regions. We primarily focus our acquisition efforts on stable, onshore basins such as West Texas, which can counterbalance our growing deepwater exploration operations, but we also respond in an opportunistic fashion to attractive acquisition opportunities in the Gulf of Mexico. Due to our existing prospect inventory, we are not compelled to make acquisitions in order to grow; however we expect to continue to pursue acquisitions aggressively on an opportunistic basis as an integral part of our growth strategy.

Our Competitive Strengths

We believe our core resources and strengths include:

Diversity of assets and activities. Our assets and operations are diversified among West Texas, and the deepwater and shelf in the Gulf of Mexico. Each of these areas involves distinctly different operational characteristics, as well as different financial and operational risks and rewards. Moreover, within these operating areas we pursue a breadth of exploration, development and acquisition activities, which in turn entail unique risks and rewards. By diversifying our assets both onshore and in the Gulf, and pursuing a full range of exploration, development and acquisition activities, we strive to mitigate concentration risk and avoid overdependence on any single activity to facilitate our growth. By maintaining a variety of investment opportunities ranging from high-risk, high-impact projects in the deepwater to relatively low-risk, repeatable projects in West Texas, we attempt to execute a balanced capital program and attain a more moderate company-wide risk profile while still affording our stockholders the significant potential upside attendant to an active deepwater exploration company.

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Large prospect inventory. We believe we have significant potential for growth through the exploration and development of our existing asset base. Taking into account our legacy assets and our recent acquisition in 2008 of the former StatoilHydro ASA shelf assets, we currently rank as the fourth largest leaseholder in the Gulf of Mexico among independent producers. Additionally, we are an active participant at MMS lease sales. We were the apparent high bidder on a company-record 23 new blocks in MMS lease sale 205 in October 2007, of which 21 were awarded, representing at least 15 exploratory projects. Moreover, in West Texas we have a large and growing asset base that we anticipate is capable of sustaining our current drilling program for a number of years. We believe that our large acreage position makes us less dependent on acquisitions for our growth as compared to companies that have less extensive drilling inventories.

Exploration expertise. Our seasoned team of geoscientists has made significant discoveries in the Gulf of Mexico and has achieved a cumulative 65% success rate during the three years ended December 31, 2007. Our geoscientists average more than 25 years each of relevant industry experience. We believe our emphasis on exploration allows us a competitive advantage over other companies who are either wholly dependent on acquisitions for growth or only sporadically engage in more limited exploration activities.

Operational control and substantial working interests. We serve as operator of projects representing approximately 66% of our production and have an average 68% working interest in our operated properties. We believe operating our production gives us a competitive advantage over non-operating interest holders since we are typically in a position to determine the extent and timing of our capital programs, as well as to assert the most direct impact on operating costs.

Extensive seismic library. We have access to recent-vintage, regional 3-D seismic data covering a significant portion of the Gulf of Mexico. We use seismic technology in our exploration program to identify and assess prospects, and in our development program to assess hydrocarbon reservoirs with a goal of optimizing drilling, workover and recompletion operations. We believe that our investment in 3-D seismic data gives us an advantage over companies with less extensive seismic resources in that we are better able to interpret geological events and stratigraphic trends on a more precise geographical basis utilizing more detailed analytical data.

Subsea tieback expertise. We have accumulated an extensive track record in the use of subsea tieback technology, which enables production from subsea wells to existing third-party production facilities through subsea flow line and umbilical infrastructure. This technology typically allows us to avoid the significant lead time and capital commitment associated with the fabrication and installation of production platforms or floating production facilities, thereby accelerating our project start ups and reducing our financial exposure. In turn, we believe this lowers the economic thresholds of our target prospects and allows us to exploit reserves that otherwise may be considered non-commercial because of the high cost of stand-alone production facilities.

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Properties

Our principal oil and gas properties are located in West Texas, and the deepwater and shelf in the Gulf of Mexico. The Gulf of Mexico properties are primarily in federal waters. The following table presents the top fields by estimated proved reserves for each principal geographic area:

Field	Operator(1)	Approximate Working Interest%	2007 Net Production (Bcfe)	Estimated Proved Reserves (Bcfe)	Estimated Proved Reserves % Oil /% Gas(2)
West Texas:					
Spraberry	Mariner	72%	10.8	384.9	71%/29%
Gulf Of Mexico Deepwater:					
Atwater Valley 426 (Bass Lite)	Mariner	42%	**	48.8	1%/99%
Green Canyon 646 (Daniel Boone)	W&T Offshore	40%		17.4	67%/33%
East Breaks 558/602 (Northwest Nansen)	Anadarko	33-50%	**	12.2	59%/41%
Mississippi Canyon 296 (Rigel)	Dominion	23%	5.0	9.7	*/99.9%
Ewing Bank 921 (North Black Widow)	ENI	35%	2.5	8.5	91%/9%
Gulf Of Mexico Shelf:					
West Cameron 110	Mariner	100%	7.2	38.7	4%/96%
Vermilion 14/26/35	Mariner	100%	1.9	33.7	8%/92%
South Pass 24	Mariner	97%	2.0	26.2	66%/34%
High Island 116	Mariner	100%	1.8	23.3	3%/97%
Vermilion 261	Mariner	79%	***	16.3	76%/24%

(1) See narrative for full name of operator

(2) NGLs are included in Oil

* Less than 1%

** Began production in February 2008

*** Shut-in for drilling operations until August 2007. See narrative below for further detail.

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West Texas Operations

Our West Texas operations historically have emphasized downspacing redevelopment activities in the prolific oil producing Spraberry field in the Permian basin. Since we began our West Texas redevelopment initiative in 2002, we have increased by approximately five-fold our net acreage position in the field and are targeting West Texas for continued expansion through our West Texas operation s headquarters in Midland, Texas. Production from the region is primarily from the Spraberry, Dean and Wolfcamp formations at depths between 6,000 and 10,000 feet, and is heavily weighted toward long-lived oil and NGLs.

During 2007, our West Texas operations produced approximately 11.2 Bcfe (11% of our total production) and accounted for approximately 388.7 Bcfe or 46% of our total estimated proved reserves at year end. Oil and NGLs accounted for 67% of total West Texas production for 2007. We drilled 115 wells in the region during 2007 with a 100% success rate. Based upon our current level of drilling activity, our drilling inventory in this area would sustain a five-year drilling program.

Our largest field in West Texas by reserves is the Spraberry Field, where we have been active for more than 20 years. We operate our wells in this field and hold an average 72% working interest. This property consists of net developed and undeveloped acres of 51,511 and 9,788, respectively on which there were 762 wells as of December 31, 2007 producing approximately 10.8 Bcfe net in 2007. This field is located in the Spraberry trend and productive zones in the field include the Spraberry, Dean and Wolfcamp formations. At year-end 2007, our share of estimated proved reserves attributed to this field was 384.9 Bcfe, consisting of 71% oil and 29% natural gas.

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Gulf of Mexico Deepwater Operations

We have acquired and maintained a significant acreage position in the deepwaters of the Gulf of Mexico. We have successfully generated and operated deepwater exploration and development projects since 1996. As a corollary to our exploration activities, we have pioneered sophisticated deepwater development strategies employing extensive subsea tieback technologies that allow us to produce our discoveries without the expense of permanent production facilities. As of December 31, 2007, we held interests in 57 deepwater blocks and 21 subsea wells. These wells were tied back to 14 host production facilities for production processing. An additional six wells were then under development for tieback to two additional host production facilities. Although we have interests throughout the Gulf of Mexico, we focus much of our efforts in infrastructure-dominated corridors where our subsea technology can be most efficiently deployed. We feel our geological understanding based on exploration success in these corridors gives us a competitive advantage in assessing prospects and vying for new leases.

Production in our deepwater Gulf of Mexico operations is largely from Pleistocene to lower Miocene aged formations and varies between oil and gas depending on formation and age. During 2007, our deepwater operation produced approximately 23.3 Bcfe (23% of our total production) and accounted for approximately 122.9 Bcfe or 15% of our total estimated proved reserves at year end. Natural gas accounted for 63% of total deepwater production for 2007. We drilled seven wells in the region during 2007 with a 43% success rate.

We operate Atwater Valley 426, known as Bass Lite, in which we hold an approximate 42% working interest. It is in the Pleistocene formation and is located in approximately 6,750 feet of water. The field consists of two development wells drilled during 2007 that are connected by a 56-mile subsea tieback to the Devil s Tower spar. Production on Bass Lite began in February 2008 with net production by month end of approximately 25.0 MMcf per day, limited by the production system designed to achieve early production while further system upgrades of the topside facilities continue during 2008. The project is expected to produce at full capacity once the topside facilities work has been completed. At year end 2007, our share of estimated proved reserves attributed to this field was 48.8 Bcfe, of which 99% are natural gas.

Green Canyon 646, known as Daniel Boone, is operated by W&T Offshore, Inc. and consists of one well in the Pliocene/Pleistocene formation. It is located in approximately 4,200 feet of water and we have an approximate 40% working interest in the well. The field is being developed and first production is expected in 2009. At year end 2007, our share of estimated proved reserves attributed to this field was 17.4 Bcfe, consisting of 67% oil and 33% natural gas.

East Breaks 558/602, known as Northwest Nansen, is operated by Anadarko Petroleum Corp. The field, which is in the Pliocene/Pleistocene formation, consists of four wells in approximately 3,500 feet of water that are connected by subsea tiebacks to the Nansen spar. We hold a 50% working interest in the East Breaks 558 well, which was completed as a gas well, and a 33% working interest in the three East Breaks 602 wells, which were completed as oil wells. The field began producing in February 2008 with a combined net daily rate by month end of approximately 26 MMcf and 2,716 Bbls of oil and NGLs. At year end 2007, our share of estimated proved reserves attributed to the field was 12.2 Bcfe, consisting of 59% oil and 41% natural gas.

Mississippi Canyon 296, known as Rigel, is operated by Dominion Resources, Inc. and began producing in 2006. It consists of one well in the Miocene formation and is located in approximately 5,200 feet of water. We hold an approximate 23% working interest. Our share of net production during 2007 was approximately 5.0 Bcfe. At year end 2007, our share of estimated proved reserves attributed to the field was 9.7 Bcfe, which is 99.9% natural gas.

Ewing Bank 921, known as North Black Widow, is operated by ENI Petroleum US and began producing in the Pliocene/Pleistocene formation in 2007. We hold an approximate 35% working interest in one well, which is located in approximately 1,700 feet of water. Our share of net production during 2007 was approximately 2.5 Bcfe. At year end 2007, our share of estimated proved reserves attributed to the field was 8.5 Bcfe, consisting of 91% oil and 9% natural gas.

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Gulf of Mexico Shelf Operations

As an operator on the Gulf of Mexico shelf for a number of years, we expanded our Gulf of Mexico shelf operations in 2006 through our acquisition of Forest s Gulf of Mexico operations. We increased our interests in shelf operations to 235 blocks at year-end 2007 from 225 blocks at year-end 2006. Due to our operational scale and substantial lease position on the shelf, we are able to pursue a diverse array of exploration and development projects on the shelf, including numerous engineering projects designed to increase production and reserves, as well as to manage production costs through optimization of topside facilities and efficiencies of scale. Drilling prospects run the gamut from relatively small, low-risk, conventional shelf projects that can be drilled from one of our numerous stationary platform facilities, to high impact, deep shelf wildcat prospects at depths approaching 20,000 total vertical feet.

During 2007, our Gulf of Mexico shelf operation produced approximately 65.8 Bcfe (66% of our total production) and accounted for approximately 324.2 Bcfe or 39% of our total estimated proved reserves at year end. Natural gas accounted for 75% of total shelf production for 2007. We drilled 18 wells in the region during 2007 with a 78% success rate.

Our largest field in the Gulf of Mexico Shelf by reserves is West Cameron 110 and consists of approximately six producing wells. We operate the field, which has been producing for more than 20 years from numerous formations in approximately 40 feet of water. We hold a 100% working interest in this field, which produced approximately 7.2 Bcfe net in 2007. At year-end 2007, estimated proved reserves attributed to this field were 38.7 Bcfe, consisting of approximately 96% natural gas and 4% oil.

We operate our 100% working interest in Vermilion 14/26/35, which consists of 10 producing wells and six saltwater injection wells in less than 20 feet of water. It has been producing for more than 20 years from numerous formations and in 2007 produced approximately 1.9 Bcfe net. At year-end 2007, estimated proved reserves attributed to this field were 33.7 Bcfe, consisting of approximately 8% oil and 92% natural gas.

We operate South Pass 24 in which we have a 97% working interest consisting of 25 producing wells in approximately 10 feet of water. South Pass 24 has been producing for more than 50 years from numerous formations, and in 2007 produced approximately 2.0 Bcfe net. At year-end 2007, estimated proved reserves attributed to this field were 26.2 Bcfe, consisting of approximately 66% oil and 34% natural gas.

We operate High Island 116 in which we have a 100% working interest consisting of one producing well in approximately 30 feet of water. It has been producing for more than 20 years and in 2007 produced approximately 1.8 Bcfe net. At year-end 2007, estimated proved reserves attributed to this field were 23.3 Bcfe, consisting of approximately 3% oil and 97% natural gas.

We operate Vermilion 261 in which we have an approximate 79% working interest consisting of two wells in approximately 130 feet of water. It has been producing for more than 20 years and in 2007 produced approximately 0.4 Bcfe net after being shut-in for drilling operations until August 2007. At year-end 2007, estimated proved reserves attributed to this field were 16.3 Bcfe, consisting of approximately 76% oil and 24% natural gas.

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The following table presents our total production volumes and revenue, excluding the effects of hedging and other revenues, by area for the year ended December 31, 2007.

	Volumes	Revenue (In thousands)
West Texas:		
Natural Gas (Bcf)	3.7	$ 25,153
Oil (Mbbls)	861.2	61,528
NGLs (Mbbls)	387.3	17,871
Total Natural Gas Equivalent (Bcfe)	11.2	104,552
Gulf of Mexico Deepwater:		
Natural Gas (Bcf)	14.7	104,840
Oil (Mbbls)	1,301.9	90,631
NGLs (Mbbls)	126.2	5,538
Total Natural Gas Equivalent (Bcfe)	23.3	201,009
Gulf of Mexico Shelf:		
Natural Gas (Bcf)	49.4	346,078
Oil (Mbbls)	2,050.3	145,634
NGLs (Mbbls)	686.3	30,783
Total Natural Gas Equivalent (Bcfe)	65.8	522,495
Total Production:		
Natural Gas (Bcf)	67.8	476,071
Oil (Mbbls)	4,213.4	297,793
NGLs (Mbbls)	1,199.8	54,192
Total Natural Gas Equivalent (Bcfe)	100.3	$ 828,056

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Estimated Proved Reserves

The following table presents certain information with respect to our estimated proved oil and natural gas reserves. The reserve information in the table below is based on estimates made in fully engineered reserve reports prepared by Ryder Scott Company, L.P. Reserve volumes and values were determined under the method prescribed by the SEC, which requires the application of period end prices and current costs held constant throughout the projected reserve life. Proved reserve estimates do not include any value for probable or possible reserves, which may exist, nor do they include any value for undeveloped acreage. The proved reserve estimates represent our net revenue interest in our properties.

	Year Ended December, 31		
	2007	2006	2005
Estimated proved oil and natural gas reserves:			
Natural gas reserves (Bcf)	448.4	426.7	207.7
Oil (MMbbls)	41.9	32.0	21.7
Natural gas liquids (MMbbls)(1)	22.6	16.1	
Total proved oil and natural gas reserves (Bcfe)	835.8	715.5	337.6
Total proved developed reserves (Bcfe)	563.9	408.7	167.4
PV10 value ($ in millions):			
Proved developed reserves	$ 2,389.1	$ 1,198.9	$ 849.6
Proved undeveloped reserves	675.1	362.6	432.2
Total PV10 value	$ 3,064.2	$ 1,561.5	$ 1,281.8
Standardized measure of discounted future net cash flows	$ 2,231.9	$ 1,239.8	$ 906.6
Prices used in calculating end of period proved reserve measures (excluding effects of hedging):			
Natural gas ($/MMBtu)	$ 6.79	$ 5.62	$ 10.05
Oil ($/bbl)	$ 96.01	$ 61.06	$ 61.04

(1) In 2005, Natural gas liquids were included as an immaterial component of the natural gas reserves in the reserve report prepared by Ryder Scott Company, L.P.

The following table sets forth certain information with respect to our estimated proved reserves by geographic area as of December 31, 2007 based on estimates made in a reserve report prepared by Ryder Scott Company, L.P.

	Estimated Proved Reserve Quantities							
	Natural Gas	Oil	NGLs	Total	PV10 Value(1)			Standardized
Geographic Area	(Bcf)	(MMbbls)	(MMbbls)	(Bcfe)	Developed	Undeveloped	Total	Measure
					(In millions of dollars)			(In millions)

West Texas	116.2	25.2	20.3	388.7	$ 737.3	$ 284.2	$ 1,021.5	
Gulf of Mexico Deepwater	86.2	5.9	0.1	122.9	575.2	98.9	674.1	
Gulf of Mexico Shelf	246.0	10.8	2.2	324.2	1,076.6	292.0	1,368.6	
Total	448.4	41.9	22.6	835.8	$ 2,389.1	$ 675.1	$ 3,064.2	$ 2,231.9
Proved Developed Reserves	326.1	25.1	14.5	563.9				

(1) PV10 Value (PV10) is a Non-GAAP measure that differs from the corollary GAAP measure standardized measure of discounted future net cash flows in that PV10 is calculated without regard to future income taxes. Management believes that the presentation of PV10 values is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our estimated proved reserves independent of our individual income tax attributes, thereby isolating the intrinsic value of the

estimated future cash flows attributable to our reserves. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. For these reasons, management uses, and believes the industry generally uses, the PV10 measure in evaluating and comparing acquisition candidates and assessing the potential return on investment related to investments in oil and natural gas properties.

PV10 is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP. For our presentation of the standardized measure of discounted future net cash flows, please see Note 15. Supplemental Oil and Gas Reserve and Standardized Measure Information in the Notes to the Consolidated Financial Statements in Part II, Item 8 in this Annual Report on Form 10-K. The table below provides a reconciliation of PV10 to standardized measure of discounted future net cash flows.

	Year Ended December 31,		
Non-GAAP Reconciliation:	**2007**	**2006**	**2005**
		(In millions)	
Present value of estimated future net revenues (PV10)	$ 3,064.2	$ 1,561.5	$ 1,281.8
Future income taxes, discounted at 10%	(832.3)	(321.7)	(375.2)
Standardized measure of discounted future net cash flows	$ 2,231.9	$ 1,239.8	$ 906.6

Uncertainties are inherent in estimating quantities of proved reserves, including many risk factors beyond our control. Reserve engineering is a subjective process of estimating subsurface accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and the interpretation thereof. As a result, estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing and production subsequent to the date of an estimate, as well as economic factors such as change in product prices, may require revision of such estimates. Accordingly, oil and natural gas quantities ultimately recovered will vary from reserve estimates.

Productive Wells

The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of December 31, 2007 and December 31, 2006.

	Year Ended December 31,			
	2007		**2006**	
	Gross	**Net**	**Gross**	**Net**
Oil	939.0	684.0	864.0	436.0
Natural Gas	223.0	130.0	257.0	143.0
Total	1,162.0	814.0	1,121.0	579.0

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Acreage

The following table sets forth certain information with respect to actual developed and undeveloped acreage in which we own an interest as of December 31, 2007.

	Year Ended December 31, 2007			
	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
West Texas	68,134	54,589	12,700	9,788
Gulf of Mexico Deepwater	91,800	37,547	270,720	186,768
Gulf of Mexico Shelf	758,529	371,079	219,952	157,938
Other Onshore	1,311	344	280	116
Total	919,774	463,559	503,652	354,610

The following table sets forth that portion of our offshore undeveloped acreage as of December 31, 2007 that is subject to expiration during the three years ended December 31, 2010. The amount of onshore undeveloped acreage subject to expiration during the period presented is not material.

	Undeveloped Acreage Subject to Expiration in the Year Ended December 31,					
	2008		2009		2010	
	Gross	Net	Gross	Net	Gross	Net
Gulf of Mexico Deepwater	56,049	34,449	11,520	8,352	17,280	1,728
Gulf of Mexico Shelf	55,320	44,250	27,406	14,844	22,280	13,064
Total	111,369	78,699	38,926	23,196	39,560	14,792

Drilling Activity

Certain information with regard to our drilling activity during the years ended December 31, 2007, 2006 and 2005 is set forth below.

	Year Ended December 31,					
	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Productive	11.00	5.96	14.00	5.83	3.00	1.13
Dry	8.00	4.91	8.00	3.65	7.00	2.44
Total	19.00	10.87	22.00	9.48	10.00	3.57

Development wells:						
Productive	121.00	60.43	168.00	86.23	93.00	54.20
Dry						
Total	121.00	60.43	168.00	86.23	93.00	54.20
Total wells:						
Productive	132.00	66.39	182.00	92.06	96.00	55.33
Dry	8.00	4.91	8.00	3.65	7.00	2.44
Total	140.00	71.30	190.00	95.71	103.00	57.77

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Marketing and Customers

We market substantially all of the oil and natural gas production from the properties we operate, as well as the properties operated by others where our interest is significant. The majority of our natural gas, oil and condensate production is sold to a variety of customers under short-term marketing arrangements at market-based prices. The following table lists customers accounting for more than 10% of our total revenues for the year indicated.

Customer	Percentage of Total Revenues for Year Ended December 31, 2007	2006	2005
BP Energy	9%	14%	*
Bridgeline Gas Distributing Company(1)			15%
ChevronTexaco and affiliates(1)	23%	23%	24%
Louis Dreyfus Energy	9%	10%	7%
Plains Marketing LP	7%	11%	10%
Shell	10%	8%	*

(1) Bridgeline Gas Distributing Company is an affiliate of ChevronTexaco

* Less than 1%

Title to Properties

Substantially all of our properties currently are subject to liens securing our bank credit facility and obligations under hedging arrangements with lenders under our bank credit facility. In addition, our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other typical burdens and encumbrances. We do not believe that any of these burdens or encumbrances materially interfere with the use of such properties in the operation of our business. Our properties may also be subject to obligations or duties under applicable laws, ordinances, rules, regulations and orders of governmental authorities.

We believe that we have satisfactory title to or rights in all of our producing properties. As is customary in the oil and natural gas industry, minimal investigation of title is made at the time of acquisition of undeveloped properties. Title investigation is made usually only before commencement of drilling operations. We believe that title issues are less likely to arise with offshore oil and natural gas properties than with onshore properties.

Competition

We believe that our leasehold acreage, exploration, drilling and production capabilities, large 3-D seismic database and technical and operational experience enable us to compete effectively. However, our primary competitors include major integrated oil and natural gas companies, nationally owned or sponsored enterprises, and domestic independent oil and natural gas companies. Many of our larger competitors possess and employ financial and personnel resources substantially greater than those available to us. Such companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and discover reserves in the future is dependent upon our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. In addition, 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.

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Royalty Relief

The Outer Continental Shelf Deep Water Royalty Relief Act (RRA), signed into law on November 28, 1995, provides that all tracts in the Gulf of Mexico west of 87 degrees, 30 minutes West longitude in water more than 200 meters deep offered for bid within five years after the RRA was enacted, will be relieved from normal federal royalties as follows:

Water Depth	Royalty Relief
200-400 meters	no royalty payable on the first 17.5 million BOE produced
400-800 meters	no royalty payable on the first 52.5 million BOE produced
800 meters or deeper	no royalty payable on the first 87.5 million BOE produced

Leases offered for bid within five years after the RRA was enacted are referred to as post-Act leases. The RRA also allows mineral interest owners the opportunity to apply for discretionary royalty relief for new production on leases acquired before the RRA was enacted, or pre-Act leases , and on leases acquired after November 28, 2000, or post-2000 leases . If the MMS determines that new production under a pre-Act lease or a post-2000 lease would not be economical without royalty relief, then the MMS may relieve a portion of the royalty to make the project economical.

In addition to granting discretionary royalty relief, the MMS has elected to include automatic royalty relief provisions in many post-2000 leases. For these post-2000 lease sales that have occurred to-date, for which the MMS has elected to include royalty relief, the MMS has specified the water depth categories and royalty suspension volumes applicable to production from leases issued in the sale.

In 2004, the MMS adopted additional royalty relief incentives for production of natural gas from reservoirs located deep under shallow waters of the Gulf of Mexico. These incentives apply to natural gas produced in water depths of less than 200 meters and from deep natural gas accumulations of at least 15,000 feet of true vertical depth. Drilling of qualified wells must have started on or after March 26, 2003, and production must begin prior to January 26, 2009.

The impact of royalty relief can be significant. Effective with lease sales in 2008, royalty rates for leases in all water depths will increase to 18.75% of production. For leases awarded in 2007 lease sales, the royalty rate is 16.7% of production in all water depths. Royalty relief can substantially improve the economics of projects located in deepwater or in shallow water and involving deep natural gas.

Many of our MMS leases that are subject to royalty relief contain language suspending royalty relief if commodity prices exceed predetermined threshold levels for a given calendar year. As a result, royalty relief for a lease in a particular calendar year may be contingent upon average commodity prices staying below the threshold price specified for that year. Since 2000, commodity prices have exceeded some of the predetermined threshold levels, except in 2002 for a number of our projects, and for the affected leases we have been ordered to pay royalties for natural gas produced in those years. However, we have contested the authority of the MMS to include price thresholds in certain of our post-Act leases. We believe that post-Act leases are entitled to automatic royalty relief under the RRA, regardless of commodity prices, and have pursued administrative and judicial remedies in this dispute with the MMS. For more information concerning the contested royalty payments and the MMS s demands, see Item 3. Legal Proceedings.

Regulation

Our operations are subject to extensive and continually changing regulation affecting the oil and natural gas industry. Many departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding on the oil and natural gas industry and its individual participants. The failure to comply with such rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our

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profitability. We do not believe that we are affected in a significantly different manner by these regulations than are our competitors.

Transportation and Sale of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the regulations promulgated thereunder by the Federal Energy Regulatory Commission, or FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. Deregulation of natural gas sales by producers began with the enactment of the Natural Gas Policy Act of 1978. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining Natural Gas Act of 1938 and Natural Gas Policy Act of 1978 price and non-price controls affecting producer sales of natural gas effective January 1, 1993. Congress could, however, re-enact price controls in the future. The FERC regulates interstate natural gas pipeline transportation rates and service conditions, which affect the marketing of gas produced by us and the revenues received by us for sales of such natural gas. The FERC requires interstate pipelines to provide open-access transportation on a non-discriminatory basis for all natural gas shippers. The FERC frequently reviews and modifies its regulations regarding the transportation of natural gas with the stated goal of fostering competition within all phases of the natural gas industry. In addition, with respect to production onshore or in state waters, the intra-state transportation of natural gas would be subject to state regulatory jurisdiction as well.

In August, 2005, Congress enacted the Energy Policy Act of 2005, or EP Act 2005. Among other matters, EP Act 2005 amends the Natural Gas Act, or NGA, to make it unlawful for any entity , including otherwise non-jurisdictional producers such as Mariner, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. On January 19, 2006, the FERC issued regulations implementing this provision. The regulations make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EP Act 2005 also gives the FERC authority to impose civil penalties for violations of the NGA up to $1,000,000 per day per violation. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted in connection with gas sales, purchases or transportation subject to FERC jurisdiction. It therefore reflects a significant expansion of the FERC s enforcement authority. We do not anticipate we will be affected any differently than other producers of natural gas.

Additional proposals and proceedings that might affect the natural gas industry are considered from time to time by Congress, the FERC, state regulatory bodies and the courts. We cannot predict when or if any such proposals might become effective or their effect, if any, on our operations. The natural gas industry historically has been closely regulated; thus, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue indefinitely into the future.

Regulation of Production

The production of oil and natural gas is subject to regulation under a wide range of state and federal statutes, rules, orders and regulations. State and federal statutes and regulations require permits for drilling operations, drilling bonds, and reports concerning operations. Texas and Louisiana, the states in which we own and operate properties, have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells, the spacing of wells, and the plugging and abandonment of wells and removal of related production equipment. Texas and Louisiana also restrict production to the market demand for oil and natural gas and several states have indicated interests in revising applicable regulations. These regulations can limit

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the amount of oil and natural gas we can produce from our wells, limit the number of wells, or limit the locations at which we can conduct drilling operations. Moreover, each state generally imposes a production or severance tax with respect to production and sale of crude oil, natural gas and gas liquids within its jurisdiction.

Most of our offshore operations are conducted on federal leases that are administered by the MMS. Such leases require compliance with detailed MMS regulations and orders pursuant to the Outer Continental Shelf Lands Act that are subject to interpretation and change by the MMS. Among other things, we are required to obtain prior MMS approval for our exploration plans and development and production plans at each lease. MMS regulations also impose construction requirements for production facilities located on federal offshore leases, as well as detailed technical requirements for plugging and abandonment of wells, and removal of platforms and other production facilities on such leases. The MMS requires lessees to post surety bonds, or provide other acceptable financial assurances, to ensure all obligations are satisfied on federal offshore leases. The cost of these surety bonds or other financial assurances can be substantial, and there is no assurance that bonds or other financial assurances can be obtained in all cases. We are currently in compliance with all MMS financial assurance requirements. Under certain circumstances, the MMS is authorized to suspend or terminate operations on federal offshore leases. Any suspension or termination of operations on our offshore leases could have an adverse effect on our financial condition and results of operations.

Our crude oil and gas production is subject to royalty interests established under the applicable leases. Royalty on production from state and private leases is generally governed by state law and royalty on production from leases on federal or Indian lands is governed by federal law. The MMS is authorized by statute to administer royalty valuation and collection for production from federal and Indian leases. MMS generally exercises this authority through standards established under its regulations and related policies. Our royalty obligations are, therefore, subject to federal and state law that changes from time to time. We do not anticipate that we will be affected by these changes any differently than other producers of crude oil and natural gas.

Environmental and Safety Regulations

Our operations are subject to numerous stringent and complex laws and regulations at the federal, state and local levels governing the discharge of materials into the environment or otherwise relating to human health and environmental protection. These laws and regulations may, among other things:

- require acquisition of a permit before drilling commences;
- restrict the types, quantities and concentrations of various materials that can be released into the environment in connection with drilling and production activities; and
- limit or prohibit construction or drilling activities in certain ecologically sensitive and other protected areas.

Failure to comply with these laws and regulations or to obtain or comply with permits may result in the assessment of administrative, civil and criminal penalties, imposition of remedial requirements and the imposition of injunctions to force future compliance. Offshore drilling in some areas has been opposed by environmental groups and, in some areas, has been restricted. Our business and prospects could be adversely affected to the extent laws are enacted or other governmental action is taken that prohibits or restricts our exploration and production activities or imposes environmental protection requirements that result in increased costs to us or the oil and natural gas industry in general.

The following is a summary of some of the existing laws and regulations to which our business operations are subject:

Spills and Releases. The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), and analogous state laws, impose joint and several liability, without regard to fault or the legality of the original act, on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include the owner and operator of the site where the release occurred, past owners and operators of the site, and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Responsible parties under CERCLA may be liable for the costs of cleaning up hazardous substances that have been released into the environment and for damages to natural resources. Additionally, it is not uncommon for neighboring landowners and other third parties to file tort claims for personal injury and property damage allegedly caused by the release of hazardous substances into the environment. In the course of our ordinary operations, we may generate waste that may fall within CERCLA s definition of a hazardous substance.

We currently own, lease or operate, and have in the past owned, leased or operated, numerous properties that for many years have been used for the exploration and production of oil and gas. Many of these properties have been operated by third parties whose actions with respect to the treatment and disposal or release of hydrocarbons or other wastes were not under our control. It is possible that hydrocarbons or other wastes may have been disposed of or released on or under such properties, or on or under other locations where such wastes may have been taken for disposal. These properties and wastes disposed thereon may be subject to CERCLA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial plugging operations to prevent future contamination, or to pay the costs of such remedial measures. Although we believe we have utilized operating and disposal practices that are standard in the industry, during the course of operations hydrocarbons and other wastes may have been released on some of the properties we own, lease or operate. We are not presently aware of any pending clean-up obligations that could have a material impact on our operations or financial condition.

The Oil Pollution Act (OPA). The OPA and regulations thereunder impose strict, joint and several liability on responsible parties for damages, including natural resource damages, resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A responsible party includes the owner or operator of an onshore facility and the lessee or permittee of the area in which an offshore facility is located. The OPA establishes a liability limit for onshore facilities of $350 million, while the liability limit for offshore facilities is equal to all removal costs plus up to $75 million in other damages. These liability limits may not apply if a spill is caused by a party s gross negligence or willful misconduct, the spill resulted from violation of a federal safety, construction or operating regulation, or if a party fails to report a spill or to cooperate fully in a clean-up.

The OPA also requires the lessee or permittee of an offshore area in which a covered offshore facility is located to provide financial assurance in the amount of $35 million to cover liabilities related to an oil spill. The amount of financial assurance required under the OPA may be increased up to $150 million depending on the risk represented by the quantity or quality of oil that is handled by a facility. The failure to comply with the OPA s requirements may subject a responsible party to civil, criminal, or administrative enforcement actions. We are not aware of any action or event that would subject us to liability under the OPA, and we believe that compliance with the OPA s financial assurance and other operating requirements will not have a material impact on our operations or financial condition.

Water Discharges. The Federal Water Pollution Control Act of 1972, also known as the Clean Water Act, imposes restrictions and controls on the discharge of produced waters and other oil and gas pollutants into navigable waters. These controls have become more stringent over the years, and it is possible that additional restrictions may be imposed in the future. Permits must be obtained to discharge pollutants into state and federal waters. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System, or NPDES, program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and gas industry into certain coastal and offshore water. The Clean Water Act provides for civil, criminal and administrative penalties for unauthorized discharges of oil and other pollutants, and imposes liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. Comparable state statutes impose liabilities and authorize penalties in the case of an unauthorized discharge of petroleum or its derivatives, or other pollutants, into state waters.

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In furtherance of the Clean Water Act, the Environmental Protection Agency (EPA) promulgated the Spill Prevention, Control, and Countermeasure (SPCC) regulations, which require facilities that possess certain threshold quantities of oil that could impact navigable waters or adjoining shorelines to prepare SPCC plans and meet specified construction and operating standards. The SPCC regulations were revised in 2002 and required the amendment of SPCC plans before February 18, 2006, if necessary, and required compliance with the implementation of such amended plans by August 18, 2006. This compliance deadline has been extended multiple times and on May 16, 2007 was extended until July 1, 2009. We have SPCC plans and similar contingency plans in place at several of our facilities, and may be required to prepare such plans for additional facilities where a spill or release of oil could reach or impact jurisdictional waters of the United States.

Air Emissions. The Federal Clean Air Act, and associated state laws and regulations, restrict the emission of air pollutants from many sources, including oil and natural gas operations. New facilities may be required to obtain permits before operations can commence, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Clean Air Act and associated state laws and regulations. We believe that compliance with the Clean Air Act and analogous state laws and regulations will not have a material impact on our operations or financial condition.

Congress is currently considering proposed legislation directed at reducing greenhouse gas emissions. Also, the U.S. Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA* held that greenhouse gases fall under the federal Clean Air Act s definition of air pollutant, which may result in future regulation of greenhouse gas emissions from stationary sources under various Clean Air Act programs. It is not possible at this time to predict how potential legislation or regulation to address greenhouse gas emissions would impact the oil and gas exploration and production business. However, future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial position, results of operations and cash flows.

Waste Handling. The Resource Conservation and Recovery Act (RCRA), and analogous state and local laws and regulations govern the management of wastes, including the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements, and liability for failure to meet such requirements, on a person who is either a generator or transporter of hazardous waste or an owner or operator of a hazardous waste treatment, stora or disposal facility. RCRA specifically excludes from the definition of hazardous waste drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil and natural gas. A similar exemption is contained in many of the state counterparts to RCRA. As a result, we are not required to comply with a substantial portion of RCRA s requirements because our operations generate minimal quantities of hazardous wastes. However, these wastes may be regulated by EPA or state agencies as solid waste. In addition, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes, and waste compressor oils, may be regulated under RCRA as hazardous waste. We do not believe the current costs of managing our wastes, as they are presently classified, to be significant. However, any repeal or modification of the oil and natural gas exploration and production exemption, or modifications of similar exemptions in analogous state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us, as well as our competitors, to incur increased operating expenses.

Endangered Species Act. The Endangered Species Act, or ESA, restricts activities that may affect endangered or threatened species or their habitats. We believe that we are in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Safety. The Occupational Safety and Health Act, or OSHA, and other similar laws and regulations govern the protection of the health and safety of employees. The OSHA hazard communication standard, EPA community right-to-know regulations under Title III of CERCLA and analogous state statutes require that information be maintained about hazardous materials used or produced in our operations and that this

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information be provided to employees, state and local governments and citizens. We believe that we are in substantial compliance with these requirements and with other applicable OSHA requirements.

Employees

As of December 31, 2007, we had 233 full-time employees. Our employees are not represented by any labor unions. We have never experienced a work stoppage or strike and we consider relations with our employees to be satisfactory.

Insurance Matters

Mariner is a member of OIL Insurance, Ltd. (OIL), an energy industry insurance cooperative, which provides the Company s primary layer of physical damage and windstorm insurance coverage. Our coverage is subject to a $10 million per-occurrence deductible for our assets and a $250 million per-occurrence loss limit. However, if a single event causes losses to all OIL-insured assets in excess of $750 million, amounts covered for such losses will be reduced on a pro-rata basis among OIL members.

In addition to our primary coverage through OIL, we also maintain commercial difference in conditions insurance that would apply (with no additional deductible) once our limits with OIL are exhausted, as well as partial business interruption insurance covering certain of our significant producing fields and certain other fields situated in hurricane prone areas. Our business interruption coverage begins to provide benefits after a 60-day waiting period once the designated field is shut-in due to a covered event and is limited to 35% of the forecast cash flow from each designated property. Our commercial policy expires June 1, 2008, and is subject to a general limit of $75 million per occurrence and in the case of named windstorms a combined annual aggregate limit of $75 million covering both property damage and business interruption.

Applicable insurance for our Hurricane Katrina and Rita claims with respect to the Gulf of Mexico assets previously acquired from Forest is provided by OIL. Our coverage for the former Forest properties is subject to a deductible of $5 million per occurrence and a $1 billion industry-wide loss limit per occurrence. OIL has advised us that the aggregate claims resulting from each of Hurricanes Katrina and Rita are expected to exceed the $1 billion per occurrence loss limit and that therefore, our insurance recovery is expected to be reduced pro-rata with all other competing claims from the storms. To the extent insurance recovery under the primary OIL policy is reduced, we believe the shortfall would be covered by applicable commercial excess insurance coverage. This excess coverage is not subject to an additional deductible and has a stated limit of $50 million per occurrence. The insurance coverage for Mariner s legacy properties is subject to a $3.75 million deductible. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources for more information.

Glossary of Oil and Natural Gas Terms

The following is a description of the meanings of some of the oil and natural gas industry terms used in this annual report. The definitions of proved developed reserves, proved reserves and proved undeveloped reserves have been abbreviated from the applicable definitions contained in Rule 4-10(a)(2-4) of Regulation S-X. The entire definitions of those terms can be viewed on the website at *http://www.sec.gov/about/forms/forms-x.pdf.*

3-D seismic data. (Three-Dimensional Seismic Data) Geophysical data that depicts the subsurface strata in three dimensions. 3-D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than two dimensional seismic data.

Appraisal well. A well drilled several spacing locations away from a producing well to determine the boundaries or extent of a productive formation and to establish the existence of additional reserves.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, of crude oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

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Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

Block. A block depicted on the Outer Continental Shelf Leasing and Official Protraction Diagrams issued by the MMS or a similar depiction on official protraction or similar diagrams issued by a state bordering on the Gulf of Mexico.

Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

Btu or British Thermal Unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

Conventional shelf well. A well drilled on the outer continental shelf to subsurface depths above 15,000 feet.

Deep shelf well. A well drilled on the outer continental shelf to subsurface depths below 15,000 feet.

Deepwater. Depths greater than 1,300 feet (the approximate depth of deepwater designation by the MMS).

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. This definition of development costs has been abbreviated from the applicable definitions contained in Rule 4-10(a)(2-4) of Regulation S-X. The entire definition of this term can be viewed on the website at *http://www.sec.gov/about/forms/forms-x.pdf.*

Development well. A well drilled within the proved boundaries of an oil or natural gas reservoir with the intention of completing the stratigraphic horizon known to be productive.

Differential. An adjustment to the price of oil or gas from an established spot market price to reflect differences in the quality and/or location of oil or gas.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Dry hole costs. Costs incurred in drilling a well, assuming a well is not successful, including plugging and abandonment costs.

Exploitation. Ordinarily considered to be a form of development within a known reservoir.

Exploration costs. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells. This definition of exploratory costs has been abbreviated from the applicable definitions contained in Rule 4-10(a)(2-4) of Regulation S-X. The entire definition of this term can be viewed on the website at *http://www.sec.gov/about/forms/forms-x.pdf.*

Exploratory well. A well drilled to find and produce oil or gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir or to extend a known reservoir.

Farm-in or farm-out. An agreement under which the owner of a working interest in an oil or gas lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the

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acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a farm-in while the interest transferred by the assignor is a farm-out.

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gas. Natural gas.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Lease operating expenses. The expenses of lifting oil or gas from a producing formation to the surface, and the transportation and marketing thereof, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs, ad valorem taxes and other expenses incidental to production, but not including lease acquisition or drilling or completion expenses.

Mbbls. Thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. Thousand cubic feet of natural gas.

Mcfe. Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

MMBls. Million barrels of crude oil or other liquid hydrocarbons.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

MMcfe. Million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

MMS. Minerals Management Service of the United States Department of the Interior.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or wells.

Net revenue interest. An interest in all oil and natural gas produced and saved from, or attributable to, a particular property, net of all royalties, overriding royalties, net profits interests, carried interests, reversionary interests and any other burdens to which the person s interest is subject.

Operator. The individual or company responsible for the exploration and/or exploitation and/or production of an oil or gas well or lease.

Payout. Generally refers to the recovery by the incurring party to an agreement of its costs of drilling, completing, equipping and operating a well before another party s participation in the benefits of the well commences or is increased to a new level.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of many states require plugging of abandoned wells.

PV10 or present value of estimated future net revenues. An estimate of the present value of the estimated future net revenues from proved oil and gas reserves at a date indicated after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of federal income taxes. The estimated future net revenues are discounted at an annual rate of 10%, in accordance with the SEC s practice, to determine their present value. The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the properties. Estimates of future net revenues are made using oil and natural gas prices and operating costs at the date indicated and held constant for the life of the reserves.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Prospect. A specific geographic area, which based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed non-producing reserves. Proved developed reserves expected to be recovered from zones behind casing in existing wells.

Proved developed producing reserves. Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production to market.

Proved developed reserves. Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. This definition of proved developed reserves has been abbreviated from the applicable definitions contained in Rule 4-10(a)(2-4) of Regulation S-X. The entire definition of this term can be viewed on the website at *http://www.sec.gov/about/forms/forms-x.pdf.*

Proved reserves. The estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. This definition of proved reserves has been abbreviated from the applicable definitions contained in Rule 4-10(a)(2-4) of Regulation S-X. The entire definition of this term can be viewed on the website at *http://www.sec.gov/about/forms/forms-x.pdf.*

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. This definition of proved undeveloped reserves has been abbreviated from the applicable definitions contained in Rule 4-10(a)(2-4) of Regulation S-X. The entire term definition can be viewed at website *http://www.sec.gov/about/forms/forms-x.pdf.*

Recompletion. The completion for production of an existing well bore in another formation from that which the well has been previously completed.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Shelf. Areas in the Gulf of Mexico with depths less than 1,300 feet. Our shelf area and operations also includes a small amount of properties and operations in the onshore and bay areas of the Gulf Coast.

Subsea tieback. A method of completing a productive well by connecting its wellhead equipment located on the sea floor by means of control umbilical and flow lines to an existing production platform located in the vicinity.

Subsea trees. Wellhead equipment installed on the ocean floor.

Standardized measure of discounted future net cash flows. The standardized measure represents value-based information about an enterprise s proved oil and gas reserves based on estimates of future cash flows, including income taxes, from production of proved reserves assuming continuation of year-end economic and operating conditions.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or gas regardless of whether or not such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

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Item 1A. *Risk Factors.*

Risks Relating to the Oil and Natural Gas Industry and to Our Business

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. To the extent that oil or natural gas comprises more than 50% of our production or estimated proved reserves, our financial results may be more sensitive to movements in prices of that commodity. 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. See Item 1. Business Estimated Proved Reserves.

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, 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 project production rates and timing of development expenditures. We 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 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, 2007, 33% of our estimated proved reserves 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 report. See Item 1. Business Estimated Proved Reserves for information about our oil and gas reserves.

In estimating future net revenues from estimated proved reserves, we assume that future prices and costs are fixed and apply a fixed discount factor. If any such assumption or the discount factor is materially inaccurate, our revenues, profitability and cash flow could be materially less than our estimates.

The present value of future net revenues from our estimated proved reserves referred to in this report is not necessarily the actual current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our estimated proved reserves 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 Item 1. Business Royalty Relief and Item 3. Legal Proceedings. 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 estimated proved reserves and their present value. In addition, the 10% discount factor that we use to calculate the net present value of future net cash flows for reporting purposes in accordance with SEC 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 natural 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.

If oil and natural gas prices decrease, we may be required to write-down the carrying value and/or the estimates of total reserves of our oil and natural gas properties.

Accounting rules applicable to us require that we review periodically the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write-down the carrying value of our oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. We may incur non-cash charges in the future, which could have a material adverse effect on our results of operations in the period taken. We may also reduce our estimates of the reserves that may be economically recovered, which could have the effect of reducing the value of our reserves.

We need to replace our reserves at a faster rate than companies whose reserves have longer production periods. Our failure to replace our reserves would result in decreasing reserves and production over time.

Unless we conduct successful exploration and development activities or acquire properties containing proven reserves, our estimated proved reserves will decline as reserves are depleted. Producing oil and natural gas reserves are generally characterized by declining production rates that vary depending on reservoir characteristics and other factors. High production rates generally result in recovery of a relatively higher percentage of reserves from properties during the initial few years of production. A significant portion of our current operations are conducted in the Gulf of

Mexico. Production from reserves in the Gulf of Mexico generally declines more rapidly than reserves from reservoirs in other producing regions. As a result, our need to replace reserves from new investments is relatively greater than those of producers who produce their reserves over a longer time period, such as those producers whose reserves are located in areas where the rate of reserve production is lower. If we are not able to find, develop or acquire additional reserves to replace our current and future production, our production rates will decline even if we drill the undeveloped locations that were included in our estimated proved reserves. Our future oil and natural gas reserves and production, and therefore our cash flow and income, are dependent on our success in economically finding or acquiring new reserves and efficiently developing our existing reserves.

Approximately 55% of our total estimated proved reserves are either developed non-producing or undeveloped and those reserves may not ultimately be produced or developed.

As of December 31, 2007, approximately 22% of our total estimated proved reserves were developed non-producing and approximately 33% were undeveloped. These reserves may not ultimately be developed or produced. Furthermore, not all of our undeveloped or developed non-producing reserves may be ultimately produced during the time periods we have planned, at the costs we have budgeted, or at all, which in turn may have a material adverse effect on our results of operations.

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 is 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. 3-D seismic data do not enable an interpreter to conclusively determine whether hydrocarbons are present or producible economically. In addition, the use of 3-D seismic and other advanced technologies require greater predrilling expenditures than other 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 events and natural disasters, such as loop currents, and hurricanes and other adverse weather conditions;
- 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 natural 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.

Exploration for oil or natural gas in the deepwater 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. Moreover, deepwater projects often lack proximity to the physical and oilfield service infrastructure present in the shallow waters of the

Gulf of Mexico, necessitating significant capital investment in subsea flow line infrastructure. Subsea tieback production systems require substantial time and the use of advanced and very sophisticated installation equipment supported by remotely operated vehicles. These operations may encounter mechanical difficulties and equipment failures that could result in significant cost overruns. As a result, a significant amount of time and capital must be invested before we can market 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. See Item 1. Business Properties Gulf of Mexico Deepwater Operations in this Annual Report on Form 10-K for information about our use of tieback technology.

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 typically enter into hedging arrangements pertaining to a substantial portion of our expected future production in order 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. Our hedging arrangements reduced the benefit we received from increases in the prices for oil and natural gas by approximately $49.3 million in 2005, increased the benefit we received by $33.0 million in 2006, and increased the benefit we received by $45.1 million in 2007. 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.

Counterparty contract default could have an adverse effect on us.

Our revenues are generated under contracts with various counterparties. Results of operations would be adversely affected as a result of non-performance by any of these counterparties of their contractual obligations under the various contracts. A counterparty s default or non-performance could be caused by factors beyond our control such as a counterparty experiencing credit default. A default could occur as a result of circumstances relating directly to the counterparty, such as defaulting on its credit obligations, or due to circumstances caused by other market participants having a direct or indirect relationship with the counterparty. Defaults by counterparties may occur from time to time, and this could negatively impact our results of operations, financial position and cash flows.

Properties we acquire 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 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 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

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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.

Increased drilling activity since 2003 has resulted in service cost increases and shortages in drilling rigs, personnel, equipment and supplies in certain areas. Shortages in availability 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. Increases in drilling activity in the United States or the Gulf of Mexico could exacerbate this situation.

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.

Financial difficulties encountered by our farm-out partners, working interest owners or third-party operators could adversely affect our ability to timely complete the exploration and development of our prospects.

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 timing or scope of drilling and development activities on properties we do not operate, and therefore we may not be in a position to control 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 United States 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 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 Item 1. Business Regulation for more information on our regulatory and environmental matters.

Compliance with MMS regulations could significantly delay or curtail our operations or require us to make material expenditures, all of which could have a material adverse effect on our financial condition or results of operations.

A significant portion of our operations are located on federal oil and natural gas leases that are administered by the MMS. As an offshore operator, we must obtain MMS approval for our exploration, development and production plans prior to commencing such operations. The MMS has promulgated regulations that, among other things, require us to meet stringent engineering and construction specifications, restrict the flaring or venting of natural gas, govern the plug and abandonment of wells located offshore and the installation and removal of all production facilities and govern the calculation of royalties and the valuation of crude oil produced from federal leases.

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 the losses sustained in 2005 from Hurricanes Katrina and Rita, as well as other factors affecting market conditions, premiums and deductibles for certain insurance policies, including windstorm insurance, have increased substantially. 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.

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Although we maintain insurance at levels that 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. In addition, we have not yet been able to determine the full extent of our insurance recovery and the net cost to us resulting from the hurricanes. See Item 1. Business Insurance Matters and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources for more information.

Risks Relating to Significant Acquisitions and Other Strategic Transactions

The evaluation and integration of significant acquisitions may be difficult.

We periodically evaluate acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy. Significant acquisitions and other strategic transactions may involve many risks, including:

- diversion of our management s attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of ours while carrying on our ongoing business;
- our exposure to unforeseen liabilities of acquired businesses, operations or properties;
- possibility of faulty assumptions underlying our expectations, including assumptions relating to reserves, future production, volumes, revenues, costs and synergies;
- difficulty associated with coordinating geographically separate organizations; and
- challenge of attracting and retaining personnel associated with acquired operations.

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 a significant acquisition, our results of operations may be lower than we expect.

The success of a significant acquisition will depend, in part, on our ability to realize anticipated growth opportunities from combining the acquired assets or operations with those of ours. Even if a combination is successful, it may not be possible to realize the full benefits we may expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame. Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices, or in oil and natural gas industry conditions, or by risks and uncertainties relating to the exploratory prospects of the combined assets or operations, or an increase in operating or other costs or other difficulties. If we fail to realize the benefits we anticipate from an acquisition, our results of operations may be adversely affected.

Financing and other liabilities of a significant acquisition may adversely affect our financial condition and results of operations or be dilutive to stockholders.

Future significant acquisitions and other strategic transactions could result in our incurring additional debt, contingent liabilities and expenses, all of which could decrease our liquidity or otherwise have a material adverse effect on our financial condition and operating results. In addition, an issuance of securities in connection with such transactions could dilute or lessen the rights of our current common stockholders.

Risks Relating to Financings

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 may require financing beyond our cash flow from operations to fully execute our business plan. 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, exploration arrangements with other parties, the issuance of debt securities, privately raised equity and borrowings from affiliates. In the future, we will require substantial capital to fund our business plan and operations. We expect to meet our needs from our excess cash flow, debt financings and additional equity offerings. 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. This could also 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.

We may not be able to generate enough cash flow to meet our debt obligations.

We expect our earnings and cash flow to vary significantly from year to year due to price volatility. As a result, the amount of debt that we can manage, in some periods, may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and commitments, including the notes. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance and, as a result, our ability to generate cash flow from operations and to pay our debt. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy or competitive initiatives of our competitors, are beyond our control.

Our debt level and the covenants in the agreements governing our debt could negatively impact our financial condition, results of operations and business prospects and prevent us from fulfilling our obligations under our debt obligations.

Our level of indebtedness and the covenants contained in the agreements governing our debt could have important consequences for our operations, including:

- making it more difficult for us to satisfy our debt obligations and increasing the risk that we may default on our debt obligations;

- requiring us to dedicate a substantial portion of our cash flow from operations to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;

limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate and other activities;

limiting management s discretion in operating our business;

limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;

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- detracting from our ability to withstand, successfully, a downturn in our business or the economy generally;
- placing us at a competitive disadvantage against less leveraged competitors; and
- making us vulnerable to increases in interest rates, because debt under our bank credit facility will, in some cases, vary with prevailing interest rates.

We may be required to repay all or a portion of our debt on an accelerated basis in certain circumstances. If we fail to comply with the covenants and other restrictions in the agreements governing our debt, it could lead to an event of default and the consequent acceleration of our obligation to repay outstanding debt. Our ability to comply with these covenants and other restrictions may be affected by events beyond our control, including prevailing economic and financial conditions.

In addition, under the terms of our bank credit facility and the indentures governing our two series of senior unsecured notes, we must comply with certain financial covenants, including current asset and total debt ratio requirements. Our ability to comply with these covenants in future periods will depend on our ongoing financial and operating performance, which in turn will be subject to general economic conditions and financial, market and competitive factors, in particular the selling prices for our products and our ability to successfully implement our overall business strategy.

The breach of any of the covenants in the indentures or the bank credit facility could result in a default under the applicable agreement, which would permit the applicable lenders or noteholders, as the case may be, to declare all amounts outstanding thereunder to be due and payable, together with accrued and unpaid interest. We may not have sufficient funds to make such payments. If we are unable to repay our debt out of cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We cannot assure that we will be able to generate sufficient cash flow to pay the interest on our debt or those future borrowings, equity financings or proceeds from the sale of assets will be available to pay or refinance such debt. The terms of our debt, including our bank credit facility, may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions, the value of our assets and our operating performance at the time of such offering or other financing. We cannot assure that any such offerings, refinancing or sale of assets could be successfully completed.

Item 1B. ***Unresolved Staff Comments.***

None.

Item 2. ***Properties.***

See Item 1. Business for discussion of oil and gas properties and locations.

We have offices in Houston and Midland, Texas and Lafayette, Louisiana. As of December 31, 2007, our leases covered approximately 68,361 square feet, 6,580 square feet and 14,376 square feet of office space in Houston, Midland and Lafayette, respectively. The leases run through October 31, 2018, October 31, 2011 and September 30, 2013 in Houston, Midland and Lafayette, respectively. The total annual costs of our leases for 2007 were approximately $1.4 million.

Item 3. ***Legal Proceedings.***

Mariner and its subsidiary, Mariner Energy Resources, Inc. (MERI), own numerous properties in the Gulf of Mexico. Certain of such properties were leased from the MMS subject to the RRA. This Act relieved lessees of the obligation to pay royalties on certain leases until a designated volume was produced. Two of these leases held by the Company and one held by MERI contained language that limited royalty relief if commodity prices exceeded predetermined levels. Since 2000, commodity prices have exceeded some of the predetermined levels, except in 2002. The Company and MERI believe the MMS did not have the authority to include commodity price threshold language in these leases and have withheld payment of royalties on the

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leases while disputing the MMS authority in pending proceedings. The Company has recorded a liability for 100% of its estimated exposure on these leases, which at December 31, 2007 was $29.1 million, including interest. The potential liability of MERI under its lease relates to production from the lease commencing July 1, 2005, the effective date of Mariner s acquisition of MERI. Legal and administrative proceedings include:

In April 2005, the Interior Board of Land Appeals denied Mariner s administrative appeal of the MMS April 2001 order asserting royalties were due for production during calendar year 2000 because price thresholds had been exceeded. In October 2005, Mariner filed suit in the U.S. District Court for the Southern District of Texas seeking judicial review of the dismissal. Upon motion of the MMS, the Company s lawsuit was dismissed on procedural grounds. In August 2006, the Company filed an appeal of such dismissal. In August 2007, the United States Court of Appeals for the Fifth Circuit affirmed the dismissal on procedural grounds. The Fifth Circuit s dismissal is now final and unappealable. However, the Company believes the royalties asserted in the MMS April 2001 order are covered by its May 2006 order noted below, which the Company is appealing.

In May 2006, the MMS issued an order asserting price thresholds were exceeded in calendar years 2000, 2001, 2003 and 2004 and, accordingly, that royalties were due under such leases on oil and gas produced in those years. Mariner has filed and is pursuing an administrative appeal of that order. The MMS has not yet made demand for non-payment of royalties alleged to be due for calendar years subsequent to 2004 on the basis of price thresholds being exceeded.

The enforceability of the price threshold provisions of leases granted pursuant to the 1995 Royalty Relief Act currently is being litigated in several administrative appeals filed by other companies in addition to Mariner, as well as in Kerr-McGee Oil & Gas Corp. v. Burton, C.A. No. 06-0439, pending in federal court for the Western District of Louisiana. By order entered October 30, 2007, the court granted Kerr-McGee s motion for summary judgment, ruling that the price threshold provisions are unlawful. On December 21, 2007, the Department of the Interior filed a Notice of Appeal of that order. We continue to monitor the case.

In the ordinary course of business, we are a claimant and/or a defendant in various legal proceedings, including proceedings as to which we have insurance coverage and those that may involve the filing of liens against us or our assets. We do not consider our exposure in these proceedings, individually or in the aggregate, to be material.

Item 4. *Submission of Matters to a Vote of Security Holders.*

Not applicable.

Executive Officers of the Registrant

The following table sets forth the names, ages (as of February 20, 2008) and titles of the individuals who are executive officers of Mariner. All executive officers hold office until their successors are elected and qualified. There are no family relationships among any of our directors or executive officers.

Name	Age	Position with Company
Scott D. Josey	50	Chairman of the Board, Chief Executive Officer and President
Dalton F. Polasek	56	Chief Operating Officer
John H. Karnes	46	Senior Vice President, Chief Financial Officer and Treasurer
Jesus G. Melendrez	49	Senior Vice President Corporate Development
Mike C. van den Bold	45	Senior Vice President and Chief Exploration Officer
Teresa G. Bushman	58	Senior Vice President, General Counsel and Secretary
Judd A. Hansen	52	Senior Vice President Shelf and Onshore
Cory L. Loegering	52	Senior Vice President Deepwater
Richard A. Molohon	53	Vice President Reservoir Engineering

Scott D. Josey Mr. Josey has served as Chairman of the Board since August 2001. Mr. Josey was appointed Chief Executive Officer in October 2002 and President in February 2005. From 2000 to 2002, Mr. Josey served as Vice President of Enron North America Corp. and co-managed its Energy Capital Resources group. From 1995 to 2000, Mr. Josey provided investment banking services to the oil and gas industry and portfolio management services. From 1993 to 1995, Mr. Josey was a Director with Enron Capital & Trade Resources Corp. in its energy investment group. From 1982 to 1993, Mr. Josey worked in all phases of drilling, production, pipeline, corporate planning and commercial activities at Texas Oil and Gas Corp. Mr. Josey is a member of the Society of Petroleum Engineers and the Independent Producers Association of America.

Dalton F. Polasek Mr. Polasek was appointed Chief Operating Officer in February 2005. From April 2004 to February 2005, Mr. Polasek served as Executive Vice President Operations and Exploration. From August 2003 to April 2004, he served as Senior Vice President Shelf and Onshore. From August 2002 to August 2003, he was Senior Vice President, and from October 2001 to January 2003, he was a consultant to Mariner. Prior to joining Mariner, Mr. Polasek was self employed from February 2001 to October 2001 and served as: Vice President of Gulf Coast Engineering for Basin Exploration, Inc. from 1996 until February 2001; Vice President of Engineering for SMR Energy Income Funds from 1994 to 1996; director of Gulf Coast Acquisitions and Engineering for General Atlantic Resources, Inc. from 1991 to 1994; and manager of planning and business development for Mark Producing Company from 1983 to 1991. He began his career in 1975 as a reservoir engineer for Amoco Production Company. Mr. Polasek is a Registered Professional Engineer in Texas and a member of the Independent Producers Association of America.

John H. Karnes Mr. Karnes was appointed Senior Vice President, Chief Financial Officer and Treasurer in October 2006. He was Senior Vice President and Chief Financial Officer of CDX Gas, LLC from July 2006 to August 2006.

He served as Executive Vice President and Chief Financial Officer of Maxxam Inc. from April 2006 to July 2006. He served as Senior Vice President and Chief Financial Officer of The Houston Exploration Company from November 2002 through December 2005. Earlier in his career, he served in senior management roles at several publicly-traded companies, including Encore Acquisition Company, Snyder Oil

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Corporation and Apache Corporation, practiced law with the national law firm of Kirkland & Ellis, and was employed in various roles in the securities industry.

Jesus G. Melendrez Mr. Melendrez was promoted to Senior Vice President Corporate Development in April 2006 and served as Vice President Corporate Development from July 2003 to April 2006. Mr. Melendrez also served as a director of Mariner from April 2000 to July 2003. From February 2000 until July 2003, Mr. Melendrez was a Vice President of Enron North America Corp. in the Energy Capital Resources group where he managed the group s portfolio of oil and gas investments. He was a Senior Vice President of Trading and Structured Finance with TXU Energy Services from 1997 to 2000, and from 1992 to 1997, Mr. Melendrez was employed by Enron in various commercial positions in the areas of domestic oil and gas financing and international project development. From 1980 to 1992, Mr. Melendrez was employed by Exxon in various reservoir engineering and planning positions.

Mike C. van den Bold Mr. van den Bold was promoted to Senior Vice President and Chief Exploration Officer in April 2006 and served as Vice President and Chief Exploration Officer from April 2004 to April 2006. From October 2001 to April 2004, he served as Vice President Exploration. Mr. van den Bold joined Mariner in July 2000 as Senior Development Geologist. From 1996 to 2000, Mr. van den Bold worked for British-Borneo Oil & Gas plc. He began his career at British Petroleum. Mr. van den Bold has over 19 years of industry experience. He is a Certified Petroleum Geologist, a Texas Board Certified Geologist and a member of the American Association of Petroleum Geologists.

Teresa G. Bushman Ms. Bushman was promoted to Senior Vice President, General Counsel and Secretary in April 2006 and served as Vice President, General Counsel and Secretary from June 2003 to April 2006. From 1996 until joining Mariner in 2003, Ms. Bushman was employed by Enron North America Corp., most recently as Assistant General Counsel representing the Energy Capital Resources group, which provided debt and equity financing to the oil and gas industry. Prior to joining Enron, Ms. Bushman was a partner with Jackson Walker, LLP, in Houston.

Judd A. Hansen Mr. Hansen was promoted to Senior Vice President Shelf and Onshore in April 2006 and served as Vice President Shelf and Onshore from February 2002 to April 2006. From April 2001 to February 2002, Mr. Hansen was self-employed as a consultant. From 1997 until March 2001, Mr. Hansen was employed as Operations Manager of the Gulf Coast Division for Basin Exploration, Inc. From 1991 to 1997, he was employed in various engineering positions at Greenhill Petroleum Corporation, including Senior Production Engineer and Workover/Completion Superintendent. Mr. Hansen started his career with Shell Oil Company in 1978 and has 29 years of experience in conducting operations in the oil and gas industry.

Cory L. Loegering Mr. Loegering was promoted to Senior Vice President Deepwater in September 2006 and served as Vice President Deepwater from August 2002 to September 2006. Mr. Loegering joined Mariner in July 1990 and since 1998 has held various positions including Vice President of Petroleum Engineering and Director of Deepwater development. Mr. Loegering was employed by Tenneco from 1982 to 1988, in various positions including as senior engineer in the economic, planning and analysis group in Tenneco s corporate offices. Mr. Loegering began his career with Conoco in 1977 and held positions in the construction, production and reservoir departments responsible for Gulf of Mexico production and development. Mr. Loegering has 30 years of experience in the industry.

Richard A. Molohon Mr. Molohon was appointed Vice President Reservoir Engineering in May 2006. He joined Mariner in January 1995 as a Senior Reservoir Engineer and since then has held various positions in reservoir engineering, economics, acquisitions and dispositions, exploration, development, and planning and basin analysis, including Senior Staff Engineer from January 2000 to January 2004, and Manager, Reserves and Economics from January 2004 to May 2006. Mr. Molohon has more than 29 years of industry experience. He began his career with Amoco Production Company as a Production Engineer from 1977 until 1980. From 1980 to 1991, he was a Project Petroleum Engineer for various subsidiaries of Tenneco, Inc. From 1991 to 1995 he was a Senior Acquisition

Engineer for General Atlantic Inc. Mr. Molohon has been a Registered Professional Engineer in Texas since 1983 and is a member of the Society of Petroleum Engineers.

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PART II

Item 5. *Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.*

Mariner s common stock commenced regular way trading on March 3, 2006 on the New York Stock Exchange (NYSE) under the symbol ME. The following table sets forth, for the periods indicated, the reported high and low closing sales prices of our common stock:

Year	Period Ended	High	Low
2006	March 3, 2006 through March 31, 2006	$ 21.00	$ 18.05
	June 30, 2006	20.65	14.81
	September 30, 2006	19.68	15.94
	December 31, 2006	21.36	17.68
2007	March 31, 2007	$ 20.33	$ 16.95
	June 30, 2007	25.65	19.30
	September 30, 2007	25.26	18.87
	December 31, 2007	25.00	20.67
2008	January 1, 2008 through February 20, 2008	$ 26.62	$ 23.69

As of February 20, 2008 there were 907 holders of record of our issued and outstanding common stock; we believe that there are significantly more beneficial holders of our stock.

We currently intend to retain our earnings for the development of our business and do not expect to pay any cash dividends. We have not paid any cash dividends for the fiscal years 2005, 2006 or 2007. Refer to Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Bank Credit Facility and Note 4. Long-Term Debt in the Notes to the Consolidated Financial Statements in Part II of this Annual Report on Form 10-K for a discussion of certain covenants in our bank credit facility and indentures governing our senior unsecured notes, which restrict our ability to pay dividends.

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Performance Graph

The following graph compares the cumulative total stockholder return for our common stock to that of the Standard & Poor s 500 Index and a peer group for the period indicated as prescribed by SEC rules. Cumulative total return means the change in share price during the measurement period, plus cumulative dividends for the measurement period (assuming dividend reinvestment), divided by the share price at the beginning of the measurement period. The graph assumes $100 was invested on March 3, 2006 (the date on which our common stock began regular way trading on the NYSE) in each of our common stock, the Standard & Poor s Composite 500 Index and a peer group.

COMPARISON OF CUMULATIVE TOTAL RETURN AMONG
MARINER ENERGY, INC., THE S&P 500 INDEX AND A DEFINED PEER GROUP[(1),(2)]

Note: The stock price performance of our common stock is not necessarily indicative of future performance.

	Cumulative Total Return(1)		
	Initial	**12/31/06**	**12/31/07**
Mariner Energy, Inc.	$ 100.00	$ 96.69	$ 112.88
S&P 500 Index	$ 100.00	$ 110.18	$ 114.07
Peer Group(2)	$ 100.00	$ 98.03	$ 107.97

(1) Total return assuming reinvestment of dividends. Assumes $100 invested on March 3, 2006 in each of our common stock, S&P 500 Index, and a peer group of companies. Initial data is taken from March 3, 2006, which corresponds to when we began regular way trading on the NYSE.

(2) Composed of the following seven independent oil and gas exploration and production companies: ATP Oil & Gas Corporation, Bois d Arc Energy, Inc., Callon Petroleum Co., Energy Partners, Ltd., Plains Exploration & Production Company, Stone Energy Corporation, and W&T Offshore, Inc.

The above information under the caption Performance Graph shall not be deemed to be soliciting material and shall not be deemed to be incorporated by reference by any general statement incorporating by reference this Form 10-K into any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, and shall not otherwise be deemed filed under such acts.

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Issuer Purchases of Equity Securities

Period	Total Number of Shares (or Units) Purchased		Average Price Paid per Share (or Unit)	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
October 1, 2007 to October 31, 2007(1)	4,999	$	22.42		
November 1, 2007 to November 30, 2007(1)	378	$	22.26		
December 1, 2007 to December 31, 2007(1)	495	$	22.19		
Total	5,872	$	22.29		

(1) These shares were withheld upon the vesting of employee restricted stock grants in connection with payment of required withholding taxes.

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Item 6. *Selected Financial Data*.

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 Merger). Prior to the Merger, we were owned indirectly by Enron Corp. As a result of the Merger, we ceased being affiliated with Enron Corp in 2004.

The selected financial data table below shows our historical consolidated financial data as of and for the years ended December 31, 2007, 2006 and 2005, the period from March 3, 2004 through December 31, 2004, the period from January 1, 2004 through March 2, 2004, and for the year ended December 31, 2003. The historical consolidated financial data as of and for the years ended December 31, 2007, 2006 and 2005, are derived from Mariner s audited Consolidated Financial Statements included herein, and the historical consolidated financial data for the periods March 3, 2004 through December 31, 2004 (Post-2004 Merger), January 1, 2004 through March 2, 2004 (Pre-2004 Merger), and as of and for the year ended December 31, 2003, are derived from Mariner s audited Consolidated Financial Statements that are not included herein. The financial information contained herein is presented in the style of Post-2004 Merger activity and Pre-2004 Merger activity 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. You should read the following data in connection with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and the Consolidated Financial Statements and related notes thereto included in Part II, Item 8 of this Annual Report on Form 10-K, where there is additional disclosure regarding the information in the following table. Mariner s historical results are not necessarily indicative of results to be expected in future periods.

	Post-2004 Merger				Pre-2004 Merger	
	Year Ended December 31,			Period from March 3, through December 31,	Period from January 1, through March 2,	Year Ended December 31,
	2007	2006	2005	2004	2004	2003
	(In thousands, except per share data)					
Statement of Operations Data:						
Total revenues(1)	$ 874,725	$ 659,505	$ 199,710	$ 174,423	$ 39,84	$ 142,543
Operating expenses(2)	174,482	105,739	32,218	23,322	5,191	30,971
Depreciation, depletion and amortization	384,321	292,180	59,469	54,281	10,630	48,339
Derivative settlement						3,222
General and administrative expense	41,126	33,372	36,766	7,641	1,131	8,098
Operating income	268,710	227,470	69,168	88,222	22,812	51,913
Interest expense, net of amounts capitalized	54,665	39,649	8,172	6,045	(5)	6,981
Provision for income taxes	77,324	67,344	21,294	28,783	8,072	9,387

Cumulative effect of changes in accounting method						1,943
Net income	143,934	121,462	40,481	53,619	14,826	38,244
Earnings per common share:						
Basic:						
Income before cumulative effect of changes in accounting method per common share	$ 1.68	$ 1.59	$ 1.24	$ 1.80	$ 0.50	$ 1.22
Cumulative effect of changes in accounting method						.07
Net income per common share basic	$ 1.68	$ 1.59	$ 1.24	$ 1.80	$ 0.50	$ 1.29
Diluted:						
Income before cumulative effect of changes in accounting method per common share	$ 1.67	$ 1.58	$ 1.20	$ 1.80	$ 0.50	$ 1.22
Cumulative effect of changes in accounting method						.07
Net income per common share diluted	$ 1.67	$ 1.58	$ 1.20	$ 1.80	$ 0.50	$ 1.29

(1) Includes effects of hedging.

(2) Operating expenses include Lease operating expense, Severance and ad valorem taxes and Transportation expenses

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	Post-2004 Merger December 31, 2007	2006	2005	2004	Pre-2004 Merger December 31, 2003
	(In thousands)				
Balance Sheet Data:(1)					
Current Assets	$ 248,980	$ 306,018	$ 141,432	$ 65,746	$ 103,081
Current Liabilities	315,189	239,727	204,006	101,412	66,590
Working capital / (deficit)	$ (66,209)	$ 66,291	$ (62,574)	$ (35,666)	$ 36,491
Property and equipment, net, full-cost method	2,420,194	2,012,062	515,943	303,773	207,872
Total assets	3,083,635	2,680,153	665,536	376,019	312,104
Long-term debt, less current maturities	779,000	654,000	156,000	115,000	
Stockholders equity	1,391,018	1,302,591	213,336	133,907	218,157

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

	Post-2004 Merger Year Ended December 31, 2007	2006	2005	Period from March 3, through December 31, 2004	Pre-2004 Merger Period from January 1, through March 2, 2004	Year Ended December 31, 2003
	(In thousands, except per share data)					
Cash Flow Data:						
Net cash provided by operating activities	$ 536,113	$ 277,161	$ 165,444	$ 135,243	$ 20,295	$ 88,909
Net cash (used) provided by investing activities	$ (643,779)	$ (561,390)	$ (247,799)	$ (132,977)	$ (15,341)	$ 52,921
Net cash (used) provided by financing activities	$ 116,676	$ 289,252	$ 84,370	$ (64,853)	$	$ (100,000)

Item 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations.***

Business Overview

We are an independent oil and natural gas exploration, development and production company with principal operations in West Texas and the Gulf of Mexico. As of December 31, 2007, approximately 67% of our total estimated proved reserves were classified as proved developed, with approximately 46% of the total estimated proved reserves located in West Texas, 15% in the Gulf of Mexico deepwater and 39% on the Gulf of Mexico shelf.

West Texas Acquisition. On December 31, 2007, Mariner acquired additional working interests in certain of its existing properties in the Spraberry field in the Permian Basin, increasing Mariner s average working interest across these properties to approximately 72%. A summary of the acquired interests includes an approximate 56% working interest in approximately 32,000 gross acres in Reagan, Midland, Dawson, Glasscock, Martin and Upton Counties, and interests in 348 (195 net) producing wells producing approximately 7.5 MMcfe per day net to the interests acquired. Ryder Scott Company, L.P. estimated net proved oil and gas reserves attributable to the acquisition of approximately 95.5 Bcfe (75% oil and NGLs). Mariner anticipates operating substantially all of the assets. Mariner financed the purchase price of approximately $122.5 million under its bank credit facility.

Forest Merger. On March 2, 2006, a subsidiary of Mariner completed a merger transaction with Forest Energy Resources, Inc. (the Forest Merger) pursuant to which Mariner effectively acquired Forest s Gulf of Mexico operations. Prior to the consummation of the Forest Merger, Forest transferred and contributed the assets and certain liabilities associated with its Gulf of Mexico operations to Forest Energy Resources.

Immediately prior to the Forest Merger, Forest distributed all of the outstanding shares of Forest Energy Resources to Forest stockholders on a pro rata basis. Forest Energy Resources then merged with a newly-formed subsidiary of Mariner, became a new wholly-owned subsidiary of Mariner, and changed its name to Mariner Energy Resources, Inc. Immediately following the Forest Merger, approximately 59% of Mariner common stock was held by stockholders of Forest and approximately 41% of Mariner common stock was held by the pre-merger stockholders of Mariner. In the Forest Merger, Mariner issued 50,637,010 shares of common stock to the stockholders of Forest Energy Resources, Inc. Our acquisition of Forest Energy Resources added approximately 298 Bcfe of estimated proved reserves. The Forest Merger has had a significant effect on the comparability of operating and financial results between periods.

Private Placement. 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 $38 million of the remaining net proceeds of approximately $44 million to repay borrowings drawn on our bank credit facility, and the balance to pay down $6 million of a $10 million promissory note payable to a former affiliate. See Note 4. Long Term Debt in the Notes to the Consolidated Financial Statements in Part II, Item 8 of this Annual Report on Form 10-K. As a result, after the private placement, an affiliate of MEI Acquisitions Holdings, LLC beneficially owned approximately 5.3% of our outstanding common stock.

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and natural 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 significantly in the future. Although we attempt to mitigate the impact of price declines and provide for more predictable cash flows 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. Conversely, the use of derivative instruments also can prevent us from realizing the full benefit of upward price movements.

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Results of Operations

Year Ended December 31, 2007 compared to Year Ended December 31, 2006

Operating and Financial Results for the Year Ended December 31, 2007
Compared to the Year Ended December 31, 2006

	Year Ended December 31, 2007	Year Ended December 31, 2006	Increase (Decrease)	% change
	(In thousands, except average sales price)			
Summary Operating Information:				
Net Production:				
Natural gas (MMcf)	67,793	56,064	11,729	21%
Oil (Mbbls)	4,214	3,237	977	30%
Natural gas liquids (Mbbls)	1,200	838	362	43%
Total natural gas equivalent (MMcfe)	100,273	80,512	19,761	25%
Average daily production (MMcfe per day)	275	221	54	25%
Hedging Activities:				
Natural Gas revenue gain	$ 58,465	$ 32,881	$ 25,584	78%
Oil revenue gain (loss)	(13,388)	90	(13,478)	> (100)%
Total hedging revenue gain (loss)	$ 45,077	$ 32,971	$ 12,106	37%
Average Sales Prices:				
Natural gas (per Mcf) realized(1)	$ 7.88	$ 7.37	$ 0.51	7%
Natural gas (per Mcf) unhedged	7.02	6.78	0.24	4%
Oil (per Bbl) realized(1)	67.50	62.63	4.87	8%
Oil (per Bbl) unhedged	70.68	59.68	11.00	18%
Natural gas liquids (per Bbl) realized(1)	45.16	48.37	(3.21)	(7)%
Natural gas liquids (per Bbl) unhedged	45.16	48.37	(3.21)	(7)%
Total natural gas equivalent ($/Mcfe) realized(1)	8.71	8.15	0.56	7%
Total natural gas equivalent ($/Mcfe) unhedged	8.26	7.74	0.52	7%
Summary of Financial Information:				
Natural gas revenue	$ 534,537	$ 412,967	$ 121,570	29%
Oil revenue	284,405	202,744	81,661	40%
Natural gas liquids revenue	54,192	40,507	13,685	34%
Lease operating expense	152,593	91,592	61,001	67%
Severance and ad valorem taxes	13,101	9,070	4,031	44%
Transportation expense	8,788	5,077	3,711	73%
Depreciation, depletion and amortization	384,321	292,180	92,141	32%
General and administrative expense	41,126	33,372	7,754	23%
Net interest expense	53,262	38,664	14,598	38%
Income before taxes and minority interest	221,259	188,806	32,453	17%
Provision for income taxes	77,324	67,344	9,980	15%
Net income	143,934	121,462	22,472	19%

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

Net Production Natural gas production increased 21% in 2007 to approximately 186 MMcf per day, compared to approximately 154 MMcf per day in 2006. Oil production increased 30% in 2007 to approximately 11,500 barrels per day, compared to approximately 8,900 barrels per day in 2006. Natural gas liquids increased 43% in 2007 and total overall production increased 25% in 2007 to approximately 275 MMcfe per day, compared to 221 MMcfe per day in 2006. Natural gas production comprised approximately 68% of total production in 2007 compared to approximately 70% in 2006. The increase in production and the oil to gas ratio resulted from the 12 full months of ownership of the Forest Gulf of Mexico operations in 2007, compared to approximately 10 months in 2006. Our Gulf of Mexico production in 2006 was adversely affected by the 2005 hurricane season, resulting in shut-in production and startup delays. As a result of ongoing repairs to pipelines, facilities, terminals and host facilities, most of the shut-in production recommenced by the end of 2006. Specifically, our Rigel project recommenced production in the first quarter of 2006, and our Pluto and Ochre projects recommenced production in the third quarter of 2006.

Production in the Gulf of Mexico increased 25% to 89.1 Bcfe for 2007 from 71.3 Bcfe for 2006, while onshore production increased 22% to 11.2 Bcfe for 2007 from 9.2 Bcfe for 2006.

Natural gas, oil and NGL revenues Total natural gas, oil and NGL revenues increased 33% to $873.1 million for 2007 compared to $656.2 million for 2006. Total natural gas revenues were $534.5 million and $413.0 million for 2007 and 2006, respectively. Total oil revenues for 2007 were $284.4 million compared to $202.8 million for 2006. Total NGL revenues increased 34% from $40.5 million in 2006 as compared to $54.2 million in 2007.

Natural gas prices (excluding the effects of hedging) for 2007 averaged $7.02/Mcf compared to $6.78/Mcf for 2006. Oil prices (excluding the effects of hedging) for 2007 averaged $70.68/Bbl compared to $59.68/Bbl for 2006. For 2007, hedges increased average natural gas pricing by $0.86/Mcf to $7.88/Mcf and decreased average oil pricing by $3.18/Bbl to $67.50/Bbl, resulting in a net recognized hedging gain of $45.1 million.

The cash activity on oil and gas derivative instruments, classified as cash flow hedges, settled for natural gas and oil produced during 2007 resulted in a $46.7 million gain. An unrealized loss of $1.6 million was recognized for 2007 related to the ineffective portion of open contracts that were not eligible for deferral under SFAS 133 due primarily to the basis differentials between the contract price, which is NYMEX-based for oil and Henry Hub-based for gas, and the indexed price at the point of sale.

Lease operating expense (including workover expenses) (LOE) was $152.6 million for 2007 compared to $91.6 million for 2006. The increase primarily was attributable to 12 full months of ownership of the Forest Gulf of Mexico shelf assets in 2007 as compared to only 10 months in 2006, which carry a higher operating cost than Mariner s legacy deepwater operations. Additionally, insurance premiums increased from $10.5 million in 2006 to $17.8 million in 2007 as a result of Hurricanes Katrina and Rita. Field costs increased $7.6 million year-over-year in West Texas with the addition of new productive wells in the Spraberry field. Per unit lease operating expenses rose to $1.52 per Mcfe for 2007 compared to $1.14 per Mcfe for 2006.

Severance and ad valorem taxes were $13.1 million and $9.1 million for 2007 and 2006, respectively. The increase was primarily attributable to increased production and appreciated property values on West Texas properties. For 2007 and 2006, severance and ad valorem taxes were $0.13 and $0.11 per Mcfe, respectively.

Transportation expense for 2007 was $8.8 million, or $0.09 per Mcfe, compared to $5.1 million, or $0.06 per Mcfe, for 2006. The increase in expense was primarily due to increased production.

Depreciation, depletion and amortization (DD&A) expense increased 32% to $384.3 million from $292.2 million for 2007 and 2006, respectively. The increase was a result of increased production due to 12 full months of ownership of the Forest Gulf of Mexico operations in 2007 as compared to only ten months in 2006, as well as an increase in the unit-of-production depreciation, depletion and amortization rate. The per unit rate increased to $3.83/Mcfe from $3.63/Mcfe for the years ended 2007 and 2006, respectively. The per unit increase was primarily due to an increase in deepwater development activities and the Forest Gulf of Mexico operations, as well as increased accretion of asset retirement obligations due to the Forest Gulf of Mexico operations.

General and administrative (G&A) expense totaled $41.1 million for the year ended 2007, compared to $33.4 million for the year ended 2006. The increase was primarily related to a $4.4 million increase in professional fees associated with system enhancements, Sarbanes-Oxley compliance efforts, insurance claim activities and an increase in health insurance costs. In addition, overhead reimbursements billed or received from working interest owners decreased $4.2 million from $16.7 million in 2006 to $12.5 million in 2007. Salaries and wages for 2007 remained relatively flat at $35.2 million as the integration of the Forest Gulf of Mexico operations has stabilized. The 2006 G&A expenses included severance, retention, relocation and transition costs of $2.6 million related to the acquisition of the Forest Gulf of Mexico operations.

Capitalized G&A related to our acquisition, exploration and development activities increased to $14.0 million in 2007 from $11.0 million for 2006.

G&A expense includes charges for share-based compensation expense of $10.9 million for 2007 compared to $10.2 million for 2006. For 2007 and 2006, $7.0 and $6.6 million of share-based compensation expense, respectively, resulted from amortization of the cost of restricted stock granted at the closing of Mariner s equity private placement in March 2005 and the remaining related to the amortization of new grants issued in 2007 and 2006 with vesting periods of three to four years. The restricted stock related to Mariner s equity private placement fully vested by May 2006 and there will be no further charges related to those stock grants.

Net interest expense increased to $53.3 million from $38.7 million for 2007 and 2006, respectively. This increase was primarily due to an increase in average debt levels to $632.1 million for 2007 from $475.1 million for 2006. Debt increased during 2007 as a result of the April 2007 issuance of $300 million principal amount of 8% Senior Notes due 2017 (the 8% Notes), as well as continuing hurricane-related repair and abandonment costs of $37.8 million. Additionally, the amendment and restatement of the bank credit facility on March 2, 2006 was treated as an extinguishment of debt for accounting purposes, and resulted in a charge of $1.2 million to interest expense. Capitalized interest decreased from $1.5 million in 2006 to $0.5 million in 2007.

Income before taxes and minority interest increased 17% to $221.3 million from $188.8 million for 2007 and 2006, respectively. This increase was primarily the result of higher operating income attributed to 12 full months of ownership of the Forest Gulf of Mexico operations.

Provision for income taxes reflected an effective tax rate of 34.9% for 2007 as compared to an effective tax rate of 35.7% for the comparable period of 2006.

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Year Ended December 31, 2006 compared to Year Ended December 31, 2005

Operating and Financial Results for the Year Ended December 31, 2006 Compared to the Year Ended December 31, 2005

	Year Ended December 31, 2006	Year Ended December 31, 2005(1)	Increase (Decrease)	% change
	(In thousands, except average sales price)			
Summary Operating Information:				
Net Production:				
Natural gas (MMcf)	56,064	18,354	37,710	205%
Oil (Mbbls)	3,237	1,791	1,446	81%
Natural gas liquids (Mbbls)	838		838	%
Total natural gas equivalent (MMcfe)	80,512	29,100	51,412	177%
Average daily production (MMcfe per day)	221	80	141	177%
Hedging Activities:				
Natural Gas revenue gain (loss)	$ 32,881	$ (30,613)	$ 63,494	207%
Oil revenue gain (loss)	90	(18,671)	18,761	100%
Total hedging revenue gain (loss)	$ 32,971	$ (49,284)	$ 82,255	167%
Average Sales Prices:				
Natural gas (per Mcf) realized(2)	$ 7.37	$ 6.66	$ 0.71	11%
Natural gas (per Mcf) unhedged	6.78	8.33	(1.55)	(19)%
Oil (per Bbl) realized(2)	62.63	41.23	21.40	52%
Oil (per Bbl) unhedged	59.68	51.66	8.02	16%
Natural gas liquids (per Bbl) realized(2)	48.37		48.37	%
Natural gas liquids (per Bbl) unhedged	48.37		48.37	%
Total natural gas equivalent ($/Mcfe) realized(2)	8.15	6.74	1.41	21%
Total natural gas equivalent ($/Mcfe) unhedged	7.74	8.43	(0.69)	(8)%
Summary of Financial Information:				
Natural gas revenue	$ 412,967	$ 122,291	$ 290,676	238%
Oil revenue	202,744	73,831	128,913	175%
Natural gas liquids revenue	40,507		40,507	%
Lease operating expense	91,592	24,882	66,710	268%
Severance and ad valorem taxes	9,070	5,000	4,070	81%
Transportation expense	5,077	2,336	2,741	117%
Depreciation, depletion and amortization	292,180	59,469	232,711	391%
General and administrative expense	33,372	36,766	(3,394)	(9)%
Net interest expense	38,664	7,393	31,271	423%
Income before taxes and minority interest	188,806	61,775	127,031	206%
Provision for income taxes	67,344	21,294	46,050	216%
Net income	121,462	40,481	80,981	200%

(1)

In 2005, an immaterial amount of NGLs representing approximately 4% of our net production was combined with natural gas.

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

Net Production Natural gas production increased 205% in 2006 to approximately 154 MMcf per day, compared to approximately 50 MMcf per day in 2005. Oil production increased 81% in 2006 to approximately 8,900 barrels per day, compared to approximately 4,900 barrels per day in 2005. Total production increased 177% in 2006 to approximately 221 MMcfe per day, compared to 80 MMcfe per day in 2005. Natural gas production comprised approximately 70% of total production in 2006 compared to approximately 63% in 2005. The increase in production and the gas to oil ratio primarily resulted from the acquisition of the Forest Gulf of Mexico operations. Production continued to be adversely affected by the 2005 hurricane season, resulting in shut-in production and startup delays. As a result of ongoing repairs to pipelines, facilities, terminals and host facilities, most of the shut-in production recommenced by the end of 2006.

In the last two quarters of 2005 our production was negatively impacted by Hurricanes Katrina and Rita. Production shut-in and deferred because of the hurricanes impact totaled approximately 6.0 to 8.0 Bcfe during

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the last two quarters of 2005. As of December 31, 2005 approximately 5.0 MMcfe per day of production remained shut-in awaiting repairs, primarily associated with our Green Canyon 178 (Baccarat) property, which was brought back on-line in January 2006. While 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 until the fourth quarter of 2005. 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). Our Rigel project recommenced production in the first quarter of 2006, and our Pluto and Ochre projects recommenced production in the third quarter of 2006.

Production in the Gulf of Mexico increased 216% to 71.3 Bcfe for 2006 from 22.5 Bcfe for 2005, while onshore production increased 39% to 9.2 Bcfe for 2006 from 6.6 Bcfe for 2005.

Natural gas, oil and NGL revenues Total natural gas, oil and NGL revenues increased 235% to $656.2 million for 2006 compared to $196.1 million for 2005. Natural gas revenues were $413.0 million and $122.3 million for 2006 and 2005, respectively. Total oil and NGL revenues for 2006 were $243.3 million compared to $73.8 million for 2005.

Natural gas prices (excluding the effects of hedging) for 2006 averaged $6.78/Mcf compared to $8.33/Mcf for 2005. Oil prices (excluding the effects of hedging) for 2006 averaged $59.68/Bbl compared to $51.66/Bbl for 2005. For 2006, hedges increased average natural gas pricing by $0.59/Mcf to $7.37/Mcf and increased average oil pricing by $2.95/Bbl to $62.63/Bbl, resulting in a net recognized hedging gain of $33.0 million.

The cash activity on contracts settled for natural gas and oil produced during 2006 resulted in an $11.3 million gain. An unrealized gain of $4.2 million was recognized for 2006 related to the ineffective portion of open contracts that were not eligible for deferral under SFAS 133 due primarily to the basis differentials between the contract price, which is NYMEX-based for oil and Henry Hub-based for gas, and the indexed price at the point of sale. In addition, the fair value of oil and natural gas derivatives acquired through the Forest Merger resulted in a $17.5 million non-cash gain. The fair value of the acquired derivatives was fully recognized in 2006.

Lease operating expense (including workover expenses) was $91.6 million for 2006 compared to $24.9 million for 2005. The increase primarily was attributable to the consolidation of the Forest Gulf of Mexico operations and increased costs attributable to the addition of new productive wells onshore. Per unit operating expenses rose to $1.14 per Mcfe for 2006 compared to $0.86 per Mcfe for 2005. Continued shut-in production from the impact of the 2005 hurricanes contributed to the increased per-unit operating costs.

Severance and ad valorem taxes were $9.1 million and $5.0 million for 2006 and 2005, respectively. The increase was primarily attributable to increased production and appreciated property values on West Texas properties. For 2006 and 2005, severance and ad valorem taxes were $0.11 and $0.17 per Mcfe, respectively.

Transportation expense for 2006 was $5.1 million, or $0.06 per Mcfe, compared to $2.3 million, or $0.08 per Mcfe, for 2005. The increase in expense was primarily due to increased production.

Depreciation, depletion and amortization expense increased 391% to $292.2 million from $59.5 million for 2006 and 2005, respectively. The increase was a result of increased production due to the consolidation of the Forest Gulf of Mexico operations, as well as an increase in the unit-of-production depreciation, depletion and amortization rate. The per unit rate increased to $3.63/Mcfe from $2.04/Mcfe for 2006 and 2005, respectively. The per unit increase was primarily due to an increase in deepwater development activities and the Forest Gulf of Mexico operations, as well as increased accretion of asset retirement obligations due to the Forest Gulf of Mexico operations.

General and administrative expense totaled $33.4 million for 2006, compared to $36.8 million for 2005. G&A expense includes charges for share-based compensation expense of $10.2 million for 2006 compared to $25.7 million for 2005. For 2006, $6.6 million of share-based compensation expense resulted from amortization of the cost of restricted stock granted at the closing of Mariner s equity private placement in March 2005

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and the remaining related to the amortization of new grants issued in 2006 with vesting periods of three to four years. The restricted stock related to Mariner s equity private placement fully vested by May 2006 and there will be no future charges related to those stock grants. The 2005 share-based compensation expense relates solely to the amortization of the restricted stock granted under Mariner s private equity placement. Included in the 2006 G&A expenses are severance, retention, relocation and transition costs of $2.6 million related to the acquisition of the Forest Gulf of Mexico operations. Salaries and wages for 2006 increased by $20.3 million compared to 2005. The increase was primarily the result of staffing additions related to the acquisition of the Forest Gulf of Mexico operations. In addition, 2005 included $2.3 million in payments to our former stockholders to terminate monitoring agreements. Reported G&A expenses for 2006 are net of $16.7 million of overhead reimbursements billed or received from other working interest owners, compared to $6.9 million for the comparable period of 2005, and capitalized G&A costs related to our acquisition, exploration and development activities during 2006 and 2005 of $11.0 million and $5.3 million, respectively.

Net interest expense increased to $38.7 million from $7.4 million for 2006 and 2005, respectively. This increase was primarily due to an increase in average debt levels to $475.1 million for 2006 from $96.7 million for 2005. The increased debt was primarily the result of the issuance of $300 million principal amount of 71/2% Senior Notes due 2013, the assumption of debt in the Forest Merger of $176.2 million, hurricane repairs and related abandonment costs of $84.3 million, and acquisition of interests in West Cameron 110/111 for $70.9 million. Additionally, the amendment and restatement of the bank credit facility on March 2, 2006 was treated as an extinguishment of debt for accounting purposes, and resulted in a charge of $1.2 million to interest expense. Capitalized interest increased from $0.7 million in 2005 to $1.5 million in 2006.

Income before taxes and minority interest increased 206% to $188.8 million from $61.8 million for 2006 and 2005, respectively. This increase was primarily the result of higher operating income attributed to the Forest Gulf of Mexico operations.

Provision for income taxes reflected an effective tax rate of 35.7% for 2006 as compared to an effective tax rate of 34.5% for the comparable period of 2005. The increase in the effective tax rate for 2006 was primarily a result of the Texas Margins tax, which was enacted during the second quarter of 2006 for all properties located in Texas.

Liquidity and Capital Resources

Financial Condition

	Years Ended December 31, 2007	2006
	(In thousands, except ratios)	
Current ratio(1)	0.8 to 1	1.3 to 1
Working capital(2)	(66,209)	66,291
Total debt	779,000	654,000
Operating cash flow(3)	622,610	490,378
Interest expense, net of capitalization	54,665	39,649
Fixed-charge coverage ratio(4)	4.96	5.66
Total cash and marketable securities less debt	(760,411)	(644,421)
Stockholders equity	1,391,018	1,302,591
Total liabilities to equity	1.22 to 1	1.06 to 1

(1) Current ratio is current assets divided by current liabilities.

(2) Working capital is the difference between current assets and current liabilities.

(3) Operating cash flow is net income before allowance for doubtful accounts, deferred income tax, DD&A, amortization of deferred financing costs, ineffectiveness of derivative instruments and share-based compensation expense. See the following Reconciliation of Non-GAAP Measure: Operating Cash Flow.

(4) Fixed-charge coverage ratio is net earnings before taxes, minority interest and fixed charges divided by fixed charges (interest expense, net of capitalization plus amortization of discounts.)

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Reconciliation of Non-GAAP Measure: Operating Cash Flow

Operating cash flow (OCF) is not a financial or operating measure under GAAP. The table below reconciles OCF to related GAAP information. We believe that OCF 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 OCF should not be considered in isolation or as a substitute for net income, operating income, cash flow from operating activities or any other measure of financial performance presented in accordance with GAAP or as a measure of our profitability or liquidity.

	Years Ended December 31,	
	2007	2006
	(In thousands)	
Cash flow from operating activities (GAAP)	$ 536,113	$ 277,161
Changes in operating assets and liabilities	86,497	213,217
Operating cash flow (Non-GAAP)	$ 622,610	$ 490,378

2007 Cash Flows

The following table presents cash payments for interest and income taxes:

	Years Ended December 31,		
	2007	2006	2005
		(In millions)	
Cash payments for interest	$ 49.1	$ 28.8	$ 6.1
Cash payments for income taxes	$ 0.6	$	$

Net cash provided by operating activities increased by $258.9 million to $536.1 million from $277.2 million for the year ended December 31, 2007 and 2006, respectively. The increase was due to greater operating revenue due to increased production of 54 MMcfe per day or $161.0 million and an increase in the realized price per Mcfe of $0.56 or $55.9 million, offset by higher lease operating expense and an increase in hurricane-related expenditures.

As of December 31, 2007, the Company had a working capital deficit of $66.1 million, including non-cash current derivative assets and liabilities and deferred tax assets and liabilities. In addition, working capital is negatively impacted by accrued capital expenditures. This deficit will be funded by cash flow from operating activities and our bank credit facility, as needed.

Net cash flows used in investing activities increased to $643.8 million from $561.4 million for the year ended December 31, 2007 and 2006, respectively, primarily due to increased capital expenditures of approximately $190.2 million attributable to increased activity in our drilling programs. This increase was partially offset by $26.8 million of restricted cash received in January 2007 from the sale of our interest in Cottonwood and $20.8 million of Forest Merger acquisition costs paid in 2006.

Net cash flows provided by financing activities were $116.7 million for the year ended December 31, 2007 compared to $289.3 million for the comparable period in 2006. The $172.6 million decrease was due primarily to repayment of $175.0 million of debt under our bank credit facility offset by proceeds from our issuance in April 2007 of $300.0 million aggregate principal amount of 8% Notes due in 2017 and financings in 2006, which were primarily used to fund the Forest Merger. On March 2, 2006, Mariner also paid the remaining balance of a term note payable to a former affiliate.

2007 Uses of Capital. Our primary uses of capital during 2007 were as follows:

funding capital expenditures (excluding hurricane repairs and acquisitions) of approximately $639.4 million;

funding hurricane repairs and hurricane-related abandonment expenditures of approximately $37.8 million;

paying interest of approximately $49.1 million;

paying the purchase price for West Texas assets of approximately $122.5 million; and

paying routine operating and administrative expenses.

2007 Capital Expenditures. The following table presents major components of our capital expenditures during 2007 compared to 2006.

	Year Ended December 31, 2007	Year Ended December 31, 2006(1)
	(In thousands)	
Capital expenditures:		
Leasehold acquisitions	$ 24,189	$ 22,405
Oil and natural gas exploration	182,645	165,705
Oil and natural gas development	448,577	359,754
Proceeds from property conveyances(2)	(4,116)	(33,829)
Acquisitions	122,895	70,928
Other items (primarily gathering system, capitalized overhead and interest)	15,952	14,988
Total capital expenditures, net of proceeds from property conveyances	$ 790,142	$ 599,951

(1) The Forest Energy Resources, Inc. merger is excluded.

(2) Proceeds from sale of Cottonwood project in 2006 (Garden Banks 244) of $31.8 million are recorded as restricted cash (Refer to Restricted Cash under Note 1. Summary of Significant Accounting Policies in the Notes to the Consolidated Financial Statements in Part II, Item 8 of this Annual Report on Form 10-K).

2007 Hurricane Expenditures. During the year ended 2007, we incurred approximately $37.8 million in hurricane expenditures resulting from Hurricanes Ivan, Katrina and Rita, of which $24.7 million were repairs and $13.1 million were hurricane-related abandonment costs. Substantially all of the costs incurred pertained to the Gulf of Mexico assets acquired from Forest. Since 2004, we have incurred approximately $131.7 million in hurricane expenditures from Hurricanes Ivan, Katrina and Rita, of which $103.1 million were repairs and $28.6 million were hurricane-related abandonment costs. Net of our deductible of $14.6 million and insurance proceeds received of $4.9 million, our insurance receivable at December 31, 2007 was $83.6 million, of which $26.7 million is expected to be settled within the next 12 months. However, due to the magnitude of Hurricanes Katrina and Rita and the complexity of the insurance claims being processed by the insurance industry, the timing of our ultimate insurance recovery cannot be ascertained. We expect to maintain a potentially significant insurance receivable for the indefinite future, while we actively pursue settlement of our claims to minimize the impact to our working capital and liquidity. Any differences between our insurance recoveries and insurance receivables will be recorded as adjustments to our oil and natural gas properties.

2007 Sources of Capital. Our primary sources of capital during 2007 were as follows:

- cash flow from operations;
- borrowings under our revolving bank credit facility; and
- proceeds from our issuance of $300 million aggregate principal amount of 8% Notes.

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Bank Credit Facility Effective January 31, 2008, Mariner further amended its bank credit facility to, among other things, increase the maximum credit availability to $1 billion for revolving loans, including up to $50 million in letters of credit, with a $750 million borrowing base as of that date. As amended, the bank credit facility will mature on January 31, 2012. On January 31, 2008, the Company borrowed $243 million under its bank credit facility to finance its Gulf of Mexico shelf acquisition, bringing total outstanding borrowings thereunder to $469 million as of that date. Mariner s obligations under the credit agreement are secured by a security interest in substantially all of the Company s oil and gas properties and certain other assets in favor of the lenders under the agreement.

During 2007, the borrowing base under the bank credit facility was $450 million. As of December 31, 2007, $179 million was outstanding under the bank credit facility, and the interest rate was 7.25%. In addition, four letters of credit totaling $4.7 million (excluding the Dedicated Letter of Credit discussed below) were outstanding, of which $4.2 million is required for plugging and abandonment obligations at certain of the Company s offshore fields. The outstanding principal balance of loans under the bank credit facility may not exceed the borrowing base. If the borrowing base falls below the sum of the amount borrowed and uncollateralized letter of credit exposure, then to the extent of the deficit, the Company must prepay borrowings and cash collateralize letter of credit exposure, pledge additional unencumbered collateral, repay borrowings and cash collateralize letters of credit on an installment basis, or effect some combination of these actions.

On March 2, 2006, Mariner obtained under its bank credit facility a dedicated $40 million letter of credit in favor of Forest to secure Mariner s performance of its obligations to drill and complete 150 wells under a drill-to-earn program (the Dedicated Letter of Credit). The Dedicated Letter of Credit was not included as a use of the borrowing base and reduced periodically by an amount equal to the product of $0.5 million times the number of wells exceeding 75 that were drilled and completed. As of December 31, 2007, Mariner drilled and completed all 150 wells under the program and the Dedicated Letter of Credit was cancelled in January 2008. The Dedicated Letter of Credit balance as of December 31, 2007 was $3.2 million.

The bank credit facility contains various restrictive covenants and other usual and customary terms and conditions, including limitations on the payment of cash dividends and other restricted payments, the incurrence of additional debt, the sale of assets and speculative hedging. The financial covenants under the bank credit facility require the Company to, among other things:

- maintain a ratio of consolidated current assets plus the unused borrowing base to consolidated current liabilities of not less than 1.0 to 1.0; and

- maintain a ratio of total debt to EBITDA, as defined in the credit agreement, of not more than 2.5 to 1.0.

The Company was in compliance with the financial covenants under the bank credit facility as of December 31, 2007.

The Company must pay a commitment fee of 0.250% to 0.375% per year on the unused availability under the bank credit facility.

Senior Notes Mariner has outstanding the following two issues of debt issued in registered transactions, referred to collectively as the Notes :

- $300 million principal amount of 71/2% Senior Notes due 2013 issued in March 2006

- $300 million principal amount of 8% Senior Notes due 2017 issued in April 2007

The Notes are senior unsecured obligations of Mariner, rank senior in right of payment to any future subordinated indebtedness, rank equally in right of payment with each other and with Mariner s existing and future senior unsecured indebtedness and are effectively subordinated in right of payment to Mariner s senior secured indebtedness, including its obligations under its bank credit facility, to the extent of the collateral securing such indebtedness, and to all existing and future indebtedness and other liabilities of any non-guarantor subsidiaries.

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The Notes are jointly and severally guaranteed on a senior unsecured basis by Mariner s existing and future domestic subsidiaries. In the future, the guarantees may be released or terminated under certain circumstances. Each subsidiary guarantee ranks senior in right of payment to any future subordinated indebtedness of the guarantor subsidiary, ranks equally in right of payment to all existing and future senior unsecured indebtedness of the guarantor subsidiary and effectively subordinate to all existing and future secured indebtedness of the guarantor subsidiary, including its guarantees of indebtedness under Mariner s bank credit facility, to the extent of the collateral securing such indebtedness.

Interest on the 71/2% Notes is payable on April 15 and October 15 of each year. The 71/2% Notes mature on April 15, 2013. Interest on the 8% Notes is payable on May 15 and November 15 of each year, beginning November 15, 2007. The 8% Notes mature on May 15, 2017. There is no sinking fund for the Notes.

The Company may redeem the 71/2% Notes at any time before April 15, 2010 and the 8% Notes at any time before May 15, 2012, in each case at a price equal to the principal amount redeemed plus a make-whole premium, using a discount rate of the Treasury rate plus 0.50% and accrued but unpaid interest. Beginning on the dates indicated below, the Company may redeem the Notes from time to time, in whole or in part, at the prices set forth below (expressed as percentages of the principal amount redeemed) plus accrued but unpaid interest:

71/2% Notes	**8% Notes**
April 15, 2010 at 103.750%	May 15, 2012 at 104.000%
April 15, 2011 at 101.875%	May 15, 2013 at 102.667%
April 15, 2012 and thereafter at 100.000%	May 15, 2014 at 101.333%
	May 15, 2015 and thereafter at 100.000%

In addition, before April 15, 2009, the Company may redeem up to 35% of the 71/2% Notes with the proceeds of equity offerings at a price equal to 107.50% of the principal amount of the 71/2% Notes redeemed. Before May 15, 2010, the Company may redeem up to 35% of the 8% Notes with the proceeds of equity offerings at a price equal to 108% of the principal amount of the 8% Notes redeemed plus accrued but unpaid interest.

If the Company experiences a change of control (as defined in each of the indentures governing the Notes), subject to certain exceptions, the Company must give holders of the Notes the opportunity to sell to the Company their Notes, in whole or in part, at a purchase price equal to 101% of the principal amount, plus accrued and unpaid interest and liquidated damages to the date of purchase.

The Company and its restricted subsidiaries are subject to certain negative covenants under each of the indentures governing the Notes. The indentures limit the ability of the Company and each of its restricted subsidiaries to, among other things:

- make investments;
- incur additional indebtedness or issue preferred stock;
- create certain liens;
- sell assets;
- enter into agreements that restrict dividends or other payments from its subsidiaries to itself;

consolidate, merge or transfer all or substantially all of its assets;

engage in transactions with affiliates;

pay dividends or make other distributions on capital stock or subordinated indebtedness; and

create unrestricted subsidiaries.

Costs associated with the 71/2% Notes offering were approximately $8.5 million, excluding discounts of $3.8 million. Costs associated with the 8% Notes offering included aggregate underwriting discounts of approximately $5.3 million and offering expenses of approximately $1.3 million.

Future Uses of Capital. Our identified needs for liquidity in the future are as follows:

funding future capital expenditures;

funding hurricane repairs and hurricane-related abandonment operations;

financing any future acquisitions that Mariner may identify;

paying routine operating and administrative expenses; and

paying other commitments comprised largely of cash settlement of hedging obligations and debt service.

2008 Capital Expenditures. We anticipate that our base operating capital expenditures for 2008 will be approximately $757 million (excluding hurricane-related expenditures and acquisitions, including an acquisition in January 2008 totaling approximately $243 million), with significant potential expansion contingent on drilling success and cash flow experience during the year. Approximately 43% of the base operating capital program is planned to be allocated to development activities, 33% to exploration activities, and the remainder to other items (primarily capitalized overhead and interest). In addition, we expect to incur additional hurricane-related abandonment costs during 2008 related to Hurricanes Katrina and Rita of approximately $42.0 million that we believe is covered under applicable insurance, although complete recovery or settlement is not expected to occur during the next 12 months.

Obligations and Commitments

Consolidated Contractual Obligations The following table presents a summary of our consolidated contractual obligations and commercial commitments as of December 31, 2007:

	Payments due by Period					
	2008	2009	2010	2011-2012	Thereafter	Total
	(In millions)					
Debt obligations(1)	$	$	$ 179.0	$	$ 600.0	$ 779.0
Letters of Credit	7.9					7.9
Interest obligations(2)	67.8	59.5	48.7	93.0	111.4	380.4
Operating leases	1.9	2.2	2.5	4.9	12.0	23.5
Abandonment liabilities	31.0	28.2	38.6	40.7	83.5	222.0
MMS royalty liabilities	29.1					29.1
Seismic obligations	14.6					14.6
Capital accrual obligations	159.0					159.0
Other liabilities(3)	90.5					90.5
Total contractual cash commitments	$ 401.8	$ 89.9	$ 268.8	$ 138.6	$ 806.9	$ 1,706.0

(1) As of December 31, 2007, we had incurred debt obligations under our bank credit facility and under our 71/2% Notes and 8% Notes.

(2) Interest obligations represent interest due on the senior unsecured notes at 7.5% and 8%. Future interest obligations under our bank credit facility are uncertain, due to the variable interest rate on fluctuating balances. Based on a 7.27% weighted average interest rate on amounts outstanding under our bank credit facility as of December 31, 2007, $13.6 million, $13.0 million and $2.2 million would be due under the bank credit facility by 2008, 2009 and 2010, respectively.

(3) Other liabilities include accrued LOE of $22.1 million, accrued liabilities of $17.0 million, gas balancing of $17.0 million, oil and gas payable of $14.4 million, accrued compensation of $8.1 million and other liabilities for $11.9 million.

Adequacy of Capital Sources and Liquidity

Future Capital Resources. Our anticipated sources of liquidity in the future are as follows:

- cash flow from operations in future periods;
- proceeds under our bank credit facility;
- proceeds from insurance policies relating to hurricane repairs; and
- proceeds from future capital markets transactions as needed.

In 2008, we intend to tailor our operating capital program (exclusive of hurricane-related expenditures and acquisitions) within our projected operating cash flow so that our operating capital requirements are largely self-sustaining under normal commodity price assumptions. We anticipate using proceeds under our bank credit facility only for working capital needs or acquisitions and not generally to fund our operations. We would generally expect to fund future acquisitions on a case by case basis through a combination of bank debt and capital markets activities. Based on our current operating plan and assumed price case, our expected cash flow from operations and continued access to our bank credit facility allows us ample liquidity to conduct our operations as planned for the foreseeable future.

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. 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. Amounts available for borrowing under our bank credit facility are largely dependent on our level of estimated proved reserves and current oil and natural gas prices. If either our estimated proved reserves or commodity prices decrease, amounts available to us to borrow under our bank credit facility could be reduced. If our cash flows are less than anticipated or amounts available for borrowing are reduced, we may be forced to defer planned capital expenditures.

Off-Balance Sheet Arrangements

Mariner s bank credit facility has a letter of credit subfacility of up to $50 million that is included as a use of the borrowing base. As of December 31, 2007, four such letters of credit totaling $4.7 million were outstanding.

Critical Accounting Policies and Estimates

Our discussion and analysis of Mariner s financial condition and results of operations are based upon Consolidated Financial Statements that have been prepared in accordance with generally accepted accounting principles in the United States of America (GAAP). The preparation of these Consolidated 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 Consolidated Financial Statements. See Note 1. Summary of Significant Accounting Policies in the Notes to the Consolidated Financial Statements in Part II, Item 8 of this Annual Report on Form 10-K. We analyze our estimates, including those related to oil and gas revenues; oil and gas properties; fair value of derivative instruments; goodwill; abandonment liabilities; income taxes; commitments and contingencies; depreciation, depletion and amortization; share-based compensation; and full-cost ceiling calculation. Our estimates are based on historical experience and various 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 Consolidated Financial Statements.

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Oil and Gas Properties

Our 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, including certain general and administrative expenses. Depletion 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 the depreciation, depletion and amortization rate.

At the end of each quarter, a full-cost ceiling limitation calculation is made whereby net capitalized costs related to proved properties less related deferred income taxes may not exceed an amount equal to the present value, discounted at 10%, of estimated future net revenues from estimated proved reserves plus the lower of cost or fair value of unproved properties less estimated future production and development costs and related income tax expense. The full-cost ceiling limitation is calculated using natural gas and oil prices in effect as of the balance sheet date and adjusted for basis or location differential, held constant over the life of the reserves.

We use derivative financial instruments that qualify for cash flow hedge accounting under Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities, (SFAS 133) to hedge against the volatility of natural gas and crude oil prices and, in accordance with SEC guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation. If net capitalized costs related to proved properties less related deferred income taxes were to exceed this limit, the excess would be impaired and a permanent write-down would be recorded on our Consolidated Statements of Operations. Additional guidance was provided in Staff Accounting Bulletin No. 47, Topic 12(D)(c)(3), primarily regarding the use of cash flow hedges, asset retirement obligations, and the effect of subsequent events on the ceiling test calculation. Once incurred, a write-down is not reversible at a later date.

Estimated Proved Reserves

Our most significant financial estimates are based on estimates of proved oil and natural gas reserves. Estimates of proved reserves are key components in determining 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. 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 Company, L.P.

Unproved Properties

The costs associated with unevaluated properties and properties under development are not initially included in the full-cost depletion base. Some unevaluated costs include but are not limited to unproved leasehold acreage, seismic data, wells and production facilities in progress, wells pending determination and capitalized interest costs associated with these projects. Unevaluated leasehold costs are transferred to the depletion base once determination has been made or upon expiration of a lease. Geological and geophysical costs, including 3-D seismic data costs, are included in the full-cost depletion base as incurred when such costs cannot be associated with specific unevaluated properties for which we own a direct interest. Seismic data costs are associated with specific unevaluated properties if the seismic data is acquired for the purpose of evaluating acreage or trends covered by a leasehold interest owned by us. We make this determination based on an analysis of leasehold and seismic maps and discussions with our Chief Exploration Officer. Geological and geophysical costs included in unproved properties are transferred to the full-cost depletion base along with the associated leasehold costs on a specific project basis. Costs associated with wells in progress and wells pending determination are transferred to the depletion base once a determination is made whether or not estimated proved reserves can be assigned to the property. Costs of dry holes are transferred to the depletion base immediately upon determination that the well is unsuccessful. All items included in our unevaluated property balance are assessed on a quarterly basis for possible impairment or reduction in value.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed in the acquisition. We account for goodwill in accordance with SFAS No. 142, Goodwill and Other Intangible Assets (SFAS 142). SFAS 142 requires an annual impairment assessment and a more frequent assessment if certain events occur that indicate impairment may have occurred. We performed the goodwill impairment assessment in the fourth quarter of 2007. The initial impairment assessment compares Mariner s net book value to its estimated fair value. If impairment is indicated, then Mariner is required to make estimates of the fair value of goodwill. The estimated fair value of goodwill is based on many factors, including future net cash flows of estimated proved reserves as well as the success of future exploration and development of unproved reserves. If the carrying amount of goodwill exceeds the estimated fair value, then a measurement of the loss is performed with any excess charged to expense. To date, no impairment to goodwill has been recorded.

Income Taxes

Our provision for taxes includes both state and federal taxes. Mariner records its federal 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. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carry forwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Valuation allowances are established when necessary to reduce deferred tax assets to the amount more likely than not to be recovered.

We apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from these estimates, which could impact our financial position, results of operations and cash flows.

Additionally, in May 2006, the State of Texas enacted substantial changes to its tax structure beginning in 2007 by implementing a new margin tax of 1% to be imposed on revenues less certain costs, as specified in the legislation.

Abandonment Liability

SFAS No. 143, Accounting for Asset Retirement Obligations, (SFAS 143) addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. We adopted SFAS 143 on January 1, 2003. SFAS 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.

To estimate the fair value of an asset retirement obligation, we employ a present value technique, which reflects certain assumptions, including our credit-adjusted risk-free interest rate, the estimated settlement date of the liability and the estimated current cost to settle the liability. Changes in timing or to the original estimate of cash flows will result in changes to the carrying amount of the liability.

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Hedging Program

We use derivative instruments in the form of natural gas and crude oil price swap agreements and costless collar arrangements in order to manage the price risk associated with future crude oil and natural gas production and fixed-price crude oil and natural gas purchase and sale commitments. Such agreements are accounted for as cash flow hedges whereby gains and losses resulting from these transactions, recorded at market value, are reported in Other Comprehensive Income as a component of Stockholders Equity in the Consolidated Balance Sheets. Once the physical production that was hedged by the contracts is delivered, then the gain or loss is recognized in Net Income in our Consolidated Statements of Operations.

We are required to assess the effectiveness of all our derivative contracts at inception and at every quarter-end. If open contracts cease to qualify for hedge accounting, mark-to-market accounting is utilized and changes in the fair value of open contracts are recognized in the Consolidated Statements of Operations. Not qualifying for hedge accounting may cause volatility in Net Income. Fair value is assessed, measured and estimated by obtaining market quotes, credit adjusted risk-free interest rates and estimated volatility factors from independent third parties. In addition, forward price curves and estimates of future volatility factors are used to assess and measure the effectiveness of our open contracts at the end of each period. The fair values we report in our Consolidated Financial Statements change as estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

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 hedged item associated with a derivative instrument matures, is sold, extinguishes or terminates, 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.

Revenue Recognition

Our natural gas, crude oil and NGL revenues are recorded using the entitlement method. Under the entitlement method, revenue is recorded when title passes based on Mariner s net interest or nominated deliveries. Mariner records its entitled share of revenues based on entitled volumes and contracted sales prices. The sales price for natural gas, crude oil and NGLs are adjusted for revenue deductions. The revenue deductions are based on contractual or historical data and do not require significant judgment. Subsequently, these revenue deductions are adjusted to reflect actual charges based on third party documents. Historically, these adjustments have been insignificant. Since there is a ready market for natural gas, crude oil and NGLs, Mariner sells the majority of its products soon after production at various locations at which time title and risk of loss pass to the buyer. As a result, Mariner maintains a minimum amount of product inventory in storage.

Gas imbalances occur when Mariner sells more or less than its entitled ownership percentage of total gas production. Any amount received in excess (overproduction) of Mariner s share is treated as a liability. If Mariner receives less than it is entitled, the shortage (underproduction) is recorded as a receivable. Imbalances are reduced either by subsequent recoupment of over-and-under deliveries or by cash settlement, as required by applicable contracts. Production imbalances are marked-to-market at the end of each month at the lowest of (i) the price in effect at the time of production, (ii) the current market price or (iii) the contract price, if a contract exists. Mariner s gas imbalances are not material, as oil and natural gas volumes sold are not significantly different from its share of production.

Share-Based Compensation Expense

We account for share-based compensation in accordance with the fair value recognition provisions of SFAS No. 123(R), Share-Based Payment (SFAS 123(R)). Under the fair value recognition provisions of SFAS 123(R), share-based compensation cost is measured at the grant date based on the value of the award and is recognized as expense over the vesting period. We utilize the Black-Scholes option pricing model to determine the fair value of share-based awards on the grant date, which requires judgment in estimating the expected life of the option and the expected volatility of our stock.

Actual results could differ significantly from these estimates, and these differences could materially impact our financial position, results of operations and cash flows.

In addition to the critical estimates discussed above, estimates are used in accounting and computing depreciation, depletion and amortization, the full cost ceiling, accruals of operating costs and production revenues.

Reclassifications and Use of Estimates in the Preparation of Consolidated Financial Statements

Some amounts from the previous years have been reclassified to conform to the 2007 presentation of Consolidated Financial Statements. These reclassifications do not affect net income.

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

Principles of Consolidation

Our Consolidated Financial Statements include our accounts and the accounts of our subsidiaries. All significant intercompany balances and transactions have been eliminated.

Recent Accounting Pronouncements

In December 2007, Financial Accounting Standards Board (FASB) issued SFAS No. 141(R), Business Combinations (SFAS 141(R)), which replaces SFAS 141. SFAS 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements, which will enable users to evaluate the nature and financial effects of the business combination. SFAS 141(R) is effective for fiscal years beginning after December 15, 2008. The adoption of SFAS 141(R) will have an impact on accounting for business combinations once adopted, but the effect is dependent upon acquisitions at that time.

In December 2007, FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of Accounting Research Bulletin No. 51 (SFAS 160), which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent s ownership interest and the valuation of retained non-controlling equity investments when a subsidiary is deconsolidated. The Statement also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. SFAS 160 is effective for fiscal years beginning after December 15, 2008. The Company has not determined the effect that the application of SFAS 160 will have on its Consolidated Financial Statements.

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In April 2007, FASB issued FASB Interpretation No. 39-1, Amendment of FASB Interpretation No. 39 (FIN 39-1), which addresses certain modifications to FASB Interpretation No. 39, Offsetting of Amounts Related to Certain Contracts, and whether a reporting entity that is party to a master netting arrangement can offset fair value amounts recognized for the right to reclaim or obligation to return cash collateral against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement in accordance with Interpretation 39. FIN 39-1 is effective for fiscal years beginning after November 15, 2007, with early application permitted. We are evaluating the impact that FIN 39-1 will have on our Consolidated Financial Statements.

During February 2007, FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (SFAS 159), which permits all entities to choose, at specified election dates, to measure eligible items at fair value. SFAS 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value, and thereby mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. This Statement also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS 159 is effective as of the beginning of an entity s first fiscal year that begins after November 15, 2007. We are evaluating the impact that this standard will have on our consolidated financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS 157), which establishes guidelines for measuring fair value and expands disclosures regarding fair value measurements. SFAS 157 does not require any new fair value measurements but rather it eliminates inconsistencies in the guidance found in various prior accounting pronouncements. SFAS 157 is effective for fiscal years beginning after November 15, 2007. Earlier adoption is encouraged, provided the company has not yet issued financial statements, including for interim periods, for that fiscal year. We are evaluating the impact that this standard will have on our consolidated financial position, results of operations or cash flows.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

Commodity Prices and Related Hedging Activities

Our major market risk exposure continues to be the prices applicable to our natural gas and oil production. The sales price of our production is primarily driven by the prevailing market price. Historically, prices received for our natural gas and oil production have been volatile and unpredictable. Hypothetically, if production levels were to remain at 2007 levels, a 10% increase in commodity prices from those as of December 31, 2007 would increase our cash flow by approximately $82.6 million for the year ended December 31, 2008.

The energy markets have historically been very volatile, and we can reasonably expect that oil and gas prices will 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. In addition, forward price curves and estimates of future volatility are used to assess and measure the ineffectiveness of our open contracts at the end of each period. If open contracts cease to qualify for hedge accounting, the mark-to-market change in fair value is recognized in oil and natural gas revenue in the Consolidated Statements of Operations. Not qualifying for hedge accounting and cash flow hedge designation will cause volatility in Net Income. The fair values we report in our Consolidated Financial Statements change as estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

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Hedge gains and losses are recorded by commodity type in oil and natural gas revenues in the Consolidated Statements of Operations. The effects on our oil and gas revenues from our hedging activities were as follows:

	Year Ended December 31, 2007	2006	2005(3)
	(In thousands)		
Cash Gain (Loss) on Settlements	$ 46,732	$ 11,273	$ (53,799)
Gain (Loss) on Hedge Ineffectiveness(1)	(1,655)	4,175	
Non-cash Gain on hedges acquired(2)		17,523	4,515
Total	$ 45,077	$ 32,971	$ (49,284)

(1) Unrealized gain (loss) recognized in natural gas revenue related to the ineffective portion of open contracts that are not eligible for deferral under SFAS 133 Accounting for Derivative Instruments and Hedging Activities , due primarily to the basis differentials between the contract price and the indexed price at the point of sale.

(2) In 2006, relating to the hedges acquired through the Forest transaction.

(3) $4.5 million of the $49.3 million loss relates to the hedge liability associated with the 2004 merger.

As of December 31, 2007, the Company had the following hedging activity outstanding:

Fixed Price Swaps	Quantity	Weighted-Average Fixed Price	December 31, 2007 Fair Value Gain/(Loss) (In thousands)
Natural Gas (MMBtus)			
January 1 December 31, 2008	40,583,847	$ 8.46	$ 27,672
January 1 December 31, 2009	31,642,084	$ 8.48	(1,494)
Crude Oil (Bbls)			
January 1 December 31, 2008	2,263,552	$ 78.99	(31,219)
January 1 December 31, 2009	2,172,210	$ 76.15	(23,158)
Total			$ (28,199)

Costless Collars	Quantity	Floor	Cap	December 31, 2007 Fair Value Gain/(Loss) (In thousands)

Natural Gas (MMBtus)					
January 1 December 31, 2008	12,347,000	$ 7.83	$ 14.60	$	7,201
Crude Oil (Bbls)					
January 1 December 31, 2008	1,195,495	$ 61.66	$ 86.81		(11,259)
Total				$	(4,058)

As of December 31, 2006, the Company had the following hedging activity outstanding:

Fixed Price Swaps	**Quantity**		**Weighted-Average Fixed Price**		**December 31, 2006 Fair Value Gain (In thousands)**
Natural Gas (MMBtus)					
January 1 December 31, 2007	15,846,323	$	9.67	$	47,855
January 1 December 31, 2008	3,059,689	$	9.58		4,344
Total				$	52,199

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Costless Collars		Quantity	Floor	Cap	December 31, 2006 Fair Value Gain (In thousands)
Natural Gas (MMBtus)					
January 1	December 31, 2007	14,106,750	$ 6.87	$ 11.82	$ 5,916
January 1	December 31, 2008	12,347,000	$ 7.83	$ 14.60	9,416
Crude Oil (Bbls)					
January 1	December 31, 2007	2,032,689	$ 59.84	$ 84.21	717
January 1	December 31, 2008	1,195,495	$ 61.66	$ 86.80	3,393
Total					$ 19,442

As of February 20, 2008, there were no hedging transactions entered into subsequent to December 31, 2007.

We have reviewed the financial strength of our counterparties and believe the credit risk associated with these swaps and costless collars to be minimal. Hedges with counterparties that are lenders under our bank credit facility are secured under the bank credit facility.

Interest Rates

Borrowings under our bank credit facility as further amended in January 2008, discussed above, mature on January 31, 2012, 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. During 2007, the interest rate on our outstanding bank debt averaged 7.27%. If the balance of our bank debt at December 31, 2007 were to remain constant, a 10% increase in market interest rates would decrease our cash flow by approximately $1.3 million for the year ended December 31, 2007.

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Item 8. ***Financial Statements and Supplementary Data.***

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MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, including Mariner s chief executive officer and chief financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting for Mariner. Mariner s internal control system was designed to provide reasonable assurance to Mariner s management and directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may deteriorate.

Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Mariner s internal control over financial reporting was effective as of December 31, 2007. Deloitte & Touche LLP, Mariner s independent auditor for 2007, has issued an attestation report on Mariner s internal control over financial reporting that is included in the accompanying Report of Independent Registered Public Accounting Firm.

/s/ SCOTT D. JOSEY	/s/ JOHN H. KARNES
Scott D. Josey, Chairman of the Board, Chief Executive Officer and President	John H. Karnes, Senior Vice President, Chief Financial Officer and Treasurer

Houston, Texas
February 29, 2008

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Mariner Energy, Inc.
Houston, Texas

We have audited the accompanying consolidated balance sheets of Mariner Energy, Inc. and subsidiaries (the Company) as of December 31, 2007 and 2006, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2007, 2006, and 2005. We also have audited the Company s internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company s management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company s internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed by, or under the supervision of, the company s principal executive and principal financial officers, or persons performing similar functions, and effected by the company s board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Mariner Energy, Inc. and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control   Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

DELOITTE & TOUCHE LLP

Houston, Texas
February 29, 2008

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MARINER ENERGY, INC.

CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2006
	(In thousands except share data)	
Current Assets:		
Cash and cash equivalents	$ 18,589	$ 9,579
Receivables, net of allowances of $2,449 and $726, respectively	157,774	149,692
Insurance receivables	26,683	61,001
Derivative financial instruments	11,863	54,488
Intangible assets	17,209	20,835
Prepaid expenses and other	10,630	10,423
Deferred tax asset	6,232	
Total current assets	248,980	306,018
Property and Equipment:		
Proved oil and gas properties, full-cost method	3,118,273	2,345,041
Unproved properties, not subject to amortization	40,455	40,246
Total oil and gas properties	3,158,728	2,385,287
Other property and equipment	15,545	13,512
Accumulated depreciation, depletion and amortization	(754,079)	(386,737)
Total property and equipment, net	2,420,194	2,012,062
Restricted Cash	5,000	31,830
Goodwill	295,598	288,504
Insurance Receivables	56,924	
Derivative Financial Instruments	691	17,153
Other Assets, net of amortization	56,248	24,586
TOTAL ASSETS	$ 3,083,635	$ 2,680,153
Current Liabilities:		
Accounts payable	$ 1,064	$ 1,822
Accrued liabilities	96,936	74,880
Accrued capital costs	159,010	99,028
Deferred income tax		26,857
Abandonment liability	30,985	29,660
Accrued interest	7,726	7,480
Derivative financial instruments	19,468	
Total current liabilities	315,189	239,727
Long-Term Liabilities:		
Abandonment liability	191,021	188,310

Deferred income tax	343,948	262,888
Derivative financial instruments	25,343	
Long-term debt, bank credit facility	179,000	354,000
Long-term debt, senior unsecured notes	600,000	300,000
Minority interest of consolidated subsidiary	1	
Other long-term liabilities	38,115	32,637
Total long-term liabilities	1,377,428	1,137,835
Commitments and Contingencies (see Note 8)		
Stockholders Equity:		
Preferred stock, \$.0001 par value; 20,000,000 shares authorized, no shares issued and outstanding at December 31, 2007 and December 31, 2006		
Common stock, \$.0001 par value; 180,000,000 shares authorized, 87,229,312 shares issued and outstanding at December 31, 2007; 180,000,000 shares authorized, 86,375,840 shares issued and outstanding at December 31, 2006	9	9
Additional paid-in-capital	1,054,089	1,043,923
Accumulated other comprehensive income/(loss)	(22,576)	43,097
Accumulated retained earnings	359,496	215,562
Total stockholders equity	1,391,018	1,302,591
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 3,083,635	$ 2,680,153

The accompanying Notes to the Consolidated Financial Statements are an integral part of these financial statements

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MARINER ENERGY, INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2007	2006	2005
	(In thousands except share data)		
Revenues:			
Natural gas	$ 534,537	$ 412,967	$ 122,291
Oil	284,405	202,744	73,831
Natural gas liquids	54,192	40,507	
Other revenues	1,591	3,287	3,588
Total revenues	874,725	659,505	199,710
Costs and Expenses:			
Lease operating expense	152,593	91,592	24,882
Severance and ad valorem taxes	13,101	9,070	5,000
Transportation expense	8,788	5,077	2,336
General and administrative expense	41,126	33,372	36,766
Depreciation, depletion and amortization	384,321	292,180	59,469
Other miscellaneous expense	6,086	744	244
Impairment of production equipment held for use			1,845
Total costs and expenses	606,015	432,035	130,542
OPERATING INCOME	268,710	227,470	69,168
Other Income/(Expenses):			
Interest income	1,403	985	779
Interest expense, net of amounts capitalized	(54,665)	(39,649)	(8,172)
Other income/(expense)	5,811		
Income Before Taxes and Minority Interest	221,259	188,806	61,775
Provision for Income Taxes	(77,324)	(67,344)	(21,294)
Minority Interest Expense	(1)		
NET INCOME	$ 143,934	$ 121,462	$ 40,481
Earnings per share:			
Net income per share basic	$ 1.68	$ 1.59	$ 1.24
Net income per share diluted	$ 1.67	$ 1.58	$ 1.20
Weighted average shares outstanding basic	85,645,199	76,352,666	32,667,582
Weighted average shares outstanding diluted	86,125,811	76,810,466	33,766,577

The accompanying Notes to the Consolidated Financial Statements are an integral part of these financial statements

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MARINER ENERGY, INC.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

	Common Stock	Stock Amount	Additional Paid-In-Capital	Accumulated Other Comprehensive Income/ (Loss)	Accumulated Retained Earnings	Total Stockholders Equity
			(In thousands)			
Balance at December 31, 2004	29,748	$ 1	$ 91,917	$ (11,630)	$ 53,619	$ 133,907
Common shares issued private equity offering	3,600	2	44,331			44,333
Common shares issued restricted stock	2,267	1	(1)			
Amortization of unearned compensation			25,129			25,129
Share-based compensation expense stock options			594			594
Contributed capital Mariner Energy, LLC and Mariner Holdings, Inc.			3,057			3,057
Merger adjustments			(4,322)			(4,322)
Comprehensive income:						
Net income					40,481	40,481
Change in fair value of derivative hedging instruments net of income taxes of ($33,318)				(61,878)		(61,878)
Hedge settlements reclassified to income net of income taxes of $17,249				32,035		32,035
Total comprehensive income (loss)				(29,843)	40,481	10,638
Balance at December 31, 2005	35,615	$ 4	$ 160,705	$ (41,473)	$ 94,100	$ 213,336
Common shares issued Forest transaction	50,637	5	886,142			886,147
Common shares issued restricted stock	907					
Treasury stock bought and cancelled on same day	(808)		(14,028)			(14,028)
Forfeiture of restricted stock	(27)					
Amortization of unearned compensation			9,248			9,248

Share-based compensation expense stock options			980			980
Stock options exercised	52		718			718
Merger adjustments			158			158
Comprehensive income:						
Net income					121,462	121,462
Change in fair value of derivative hedging instruments net of income taxes of $35,930				63,139		63,139
Hedge settlements reclassified to income net of income taxes of $11,540				21,431		21,431
Total comprehensive income				84,570	121,462	206,032
Balance at December 31, 2006	86,376	$ 9	$ 1,043,923	$ 43,097	$ 215,562	$ 1,302,591
Common shares issued restricted stock	906					
Treasury stock bought and cancelled on same day	(72)		(1,553)			(1,553)
Forfeiture of restricted stock	(45)		(907)			(907)
Amortization of unearned compensation			10,375			10,375
Share-based compensation expense stock options			1,422			1,422
Stock options exercised	64		829			829
Comprehensive income:						
Net income					143,934	143,934
Change in fair value of derivative hedging instruments net of income taxes of ($52,385)				(94,935)		(94,935)
Hedge settlements reclassified to income net of income taxes of $15,815				29,262		29,262
Total comprehensive income				(65,673)	143,934	78,261
Balance at December 31, 2007	87,229	$ 9	$ 1,054,089	$ (22,576)	$ 359,496	$ 1,391,018

The accompanying Notes to the Consolidated Financial Statements are an integral part of these financial statements

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MARINER ENERGY, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2007	2006	2005
	(In thousands)		
Cash flow from operating activities:			
Net income	$ 143,934	$ 121,462	$ 40,481
Adjustments to reconcile net income to net cash provided by operating activities:			
Allowance for doubtful accounts	1,723	226	500
Deferred income tax	77,324	67,344	21,294
Depreciation, depletion and amortization	384,321	295,292	60,640
Amortization of deferred financing costs	2,763		
Ineffectiveness of derivative instruments	1,655	(4,175)	
Share-based compensation	10,890	10,229	25,726
Impairment of production equipment held for use			1,845
Changes in operating assets and liabilities:			
Receivables	(9,805)	(12,972)	(33,416)
Insurance receivables	(22,606)	(55,690)	(4,542)
Prepaid expenses and other	(23,406)	18,626	(843)
Accounts payable and accrued liabilities	(30,680)	(169,819)	53,759
Net realized loss on derivative contracts acquired		6,638	
Net cash provided by operating activities	536,113	277,161	165,444
Cash flow from investing activities:			
Acquisitions and additions to property and equipment	(674,712)	(542,581)	(247,817)
Property conveyances	4,102	33,829	18
Purchase price adjustment		(20,808)	
Restricted cash designated for investment	26,830	(31,830)	
Minority interest	1		
Net cash used in investing activities	(643,779)	(561,390)	(247,799)
Cash flow from financing activities:			
Debt and working capital acquired from Forest Energy Resources, Inc.		(176,200)	
Repayment of term note		(4,000)	(6,000)
Credit facility borrowings (repayments), net	(175,000)	202,000	47,000
Proceeds from private equity offering			44,331
Proceeds from note offering	300,000	300,000	
Repurchase of stock	(1,553)	(14,027)	
Net realized loss on derivative contracts acquired		(6,638)	
Proceeds from exercise of stock options	829	718	
Deferred offering costs	(6,600)	(12,601)	(3,840)

Capital contributions from affiliates			2,879
Partner contributions/ (distributions)	(1,000)		
Net cash provided by financing activities	116,676	289,252	84,370
Increase in Cash and Cash Equivalents	9,010	5,023	2,015
Cash and Cash Equivalents at Beginning of Period	9,579	4,556	2,541
Cash and Cash Equivalents at End of Period	$ 18,589	$ 9,579	$ 4,556

The accompanying Notes to the Consolidated Financial Statements are an integral part of these financial statements

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MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
For the Years Ended December 31, 2007, 2006 and 2005

Note 1. Summary of Significant Accounting Policies

Mariner Energy, Inc. (Mariner or the Company) is an independent oil and gas exploration, development and production company with principal operations in West Texas and in the Gulf of Mexico, both shelf and deepwater. Unless otherwise indicated, references to Mariner , the Company , we , our , ours and us refer to Mariner Energy and its subsidiaries collectively.

Cash and Cash Equivalents All short-term, highly liquid investments that have an original maturity date of three months or less are considered cash equivalents.

Restricted Cash In connection with the sale of the Company s interest in Cottonwood, see Note 3. Acquisitions and Dispositions , net cash proceeds were deposited in escrow with qualified intermediaries for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code. The proceeds were designated for the potential future acquisition of natural gas and oil assets and were invested in interest-bearing accounts with creditworthy financial institutions. The reporting requirements of Section 1031 required the Company to identify replacement property within 45 days. The Company did not identify replacement property within the required time period and received proceeds and interest of $32.0 million on January 19, 2007.

Receivables Substantially all of the Company s receivables arise from sales of oil or natural gas, or from reimbursable expenses billed to the other participants in oil and gas wells for which the Company serves as operator. We routinely assess the recoverability of all material trade and other receivables to determine their collectability. We accrue a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated.

Insurance receivables The balance at December 31, 2007 is repair-related costs incurred to bring productive properties back to operating condition after sustaining significant damage from Hurricanes Ivan, Katrina and Rita in 2004 and 2005. We believe our insurance receivable is collectable under our insurance policies. Any differences between our insurance recoveries and insurance receivables will be recorded as an adjustment to oil and gas properties.

Oil and Gas Properties Our 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, including certain general and administrative expenses (G&A). 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 the depreciation, depletion and amortization rate.

At the end of each quarter, a full-cost ceiling limitation calculation is performed whereby net capitalized costs related to proved and unproved properties less related deferred income taxes may not exceed a ceiling limitation. The ceiling limitation is the amount equal to the present value discounted at 10% of estimated future net revenues from estimated proved reserves plus the lower of cost or fair value of unproved properties less estimated future production and development costs and net of related income tax effect. The full-cost ceiling limitation is calculated using natural gas and oil prices in effect as of the balance sheet date and is adjusted for basis or location differential. Price is held constant over the life of the reserves. We use derivative financial instruments that qualify for cash flow hedge accounting under Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities, (SFAS 133) to hedge against the volatility of natural gas prices and, in accordance with Securities and Exchange Commission (SEC) guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation. If net capitalized costs related to proved properties less related deferred income taxes were to exceed the ceiling limitation, the excess would be impaired and a permanent write-down would be recorded in the Consolidated Statements of Operations. Additional guidance was provided in Staff

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2007, 2006 and 2005

Accounting Bulletin No. 47, Topic 12(D)(c)(3), primarily regarding the use of cash flow hedges, asset retirement obligations, and the effect of subsequent events on the ceiling test calculation. Once incurred, a write-down is not reversible at a later date.

Unproved Properties The costs associated with unevaluated properties and properties under development are not initially included in the full-cost amortization base. These costs relate to unproved leasehold acreage and include costs for seismic data, wells and production facilities in progress and wells pending determination together with interest costs capitalized for these projects. Unevaluated leasehold costs are transferred to the amortization base once determination has been made or upon expiration of a lease. Geological and geophysical costs, including 3-D seismic data costs, are included in the full-cost amortization base as incurred when such costs cannot be associated with specific unevaluated properties for which we own a direct interest. Seismic data costs are associated with specific unevaluated properties if the seismic data is acquired for the purpose of evaluating acreage or trends covered by a leasehold interest owned by us. We make this determination based on an analysis of leasehold and seismic maps and discussions with our Chief Exploration Officer. Geological and geophysical costs included in unproved properties are transferred to the full-cost amortization base along with the associated leasehold costs on a specific project basis. Costs associated with wells in progress and wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. Costs of dry holes are transferred to the amortization base immediately upon determination that the well is unsuccessful. All items included in our unevaluated property balance are assessed on a quarterly basis for possible impairment or reduction in value.

Other Property and Equipment Other property and equipment consists of IT equipment, office furniture and fixtures, leasehold improvements as well as a gas gathering system. Depreciation of other property and equipment is provided on a straight-line basis over their estimated useful lives, which range from three to twenty-two years.

Prepaid Expenses and Other Prepaid expenses and other includes $5.3 million of prepaid insurance and $5.3 million for other prepaids and deposits at December 31, 2007. Prepaid expenses and other at December 31, 2006 includes $4.9 million of prepaid insurance and $5.5 million of other prepaids and deposits.

Other Assets Other assets at December 31, 2007 were primarily comprised of $18.9 million of oil and gas lease and well equipment held in inventory, $17.6 million earnest money for the Gulf of Mexico shelf acquisition, $13.9 million of amortizable note offering costs and discounts, $0.6 million of amortizable bank fees, $4.9 million of long-term deposits and the remaining balance consisting of deferred acquisition costs of $0.3 million. Other assets at December 31, 2006 were primarily comprised of $10.2 million of amortizable note offering costs and discounts, $2.4 million of oil and gas lease and well equipment held in inventory, $1.1 million of amortizable bank fees, $4.0 million of prepaid seismic costs and the remaining balance consist of long-term deposits of $6.7 million. Other assets are net of accumulated amortization as of December 31, 2007 and 2006 of $3.6 million and $5.0 million, respectively.

Goodwill Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed in the acquisition. We account for goodwill in accordance with SFAS No. 142 Goodwill and Other Intangible Assets (SFAS 142). SFAS 142 requires an annual impairment assessment and a more frequent assessment if certain events occur that indicate impairment may have occurred. We performed the goodwill impairment assessment in the fourth quarter of 2007. The initial impairment assessment compares the Company s net book value to its estimated fair value. If impairment is indicated, then the Company is required to make estimates of the fair value of goodwill. The estimated fair value of goodwill is based on many factors, including future net cash flows of estimated proved reserves as well as the success of future exploration and development of unproved reserves. If the carrying amount of goodwill exceeds the estimated fair value, then a measurement of the loss is performed with any

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MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2007, 2006 and 2005

excess charged to expense. To date, no impairment to goodwill has been recorded. In 2007, goodwill was adjusted for differences between book and tax basis relating to Louisiana deferred income taxes.

Income Taxes Our provision for taxes includes both state and federal taxes. The Company records its federal 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. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carry forwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Valuation allowances are established when necessary to reduce deferred tax assets to the amount more likely than not to be recovered.

We apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from these estimates, which could impact our financial position, results of operations and cash flows.

Additionally, in May 2006, the State of Texas enacted substantial changes to its tax structure beginning in 2007 by implementing a new margin tax of 1% to be imposed on revenues less certain costs, as specified in the legislation.

Abandonment Liability SFAS No. 143, Accounting for Asset Retirement Obligations, (SFAS 143) addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. The Company adopted SFAS 143 on January 1, 2003. SFAS 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.

To estimate the fair value of an asset retirement obligation, we employ a present value technique, which reflects certain assumptions, including our credit-adjusted risk-free interest rate, the estimated settlement date of the liability and the estimated current cost to settle the liability. Changes in timing or to the original estimate of cash flows will result in changes to the carrying amount of the liability.

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2007, 2006 and 2005

The following roll forward is provided as a reconciliation of the beginning and ending aggregate carrying amounts of the asset retirement obligation.

		(In millions)
Abandonment Liability as of December 31, 2005(1)	$	49.5
Liabilities Incurred		29.6
Liabilities Settled		(31.1)
Accretion Expense		15.3
Revisions to previous estimates		(10.5)
Liabilities incurred from assets acquired(2)		165.2
Abandonment Liability as of December 31, 2006(3)	$	218.0
Liabilities Incurred		6.6
Liabilities Settled		(57.8)
Accretion Expense		17.0
Revisions to previous estimates		38.2
Abandonment Liability as of December 31, 2007(4)	$	222.0

(1) Includes $11.4 million classified as a current accrued liability at December 31, 2005.

(2) Represents the fair value of the asset retirement obligation acquired through the Forest Merger.

(3) Includes $29.7 million classified as a current accrued liability at December 31, 2006.

(4) Includes $31.0 million classified as a current accrued liability at December 31, 2007.

Hedging Program The Company utilizes derivative instruments 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 and fixed-price crude oil and natural gas purchase and sale commitments. Such agreements are accounted for as hedges using the deferral method of accounting. Gains and losses resulting from these transactions, recorded at market value, are deferred and recorded in Accumulated Other Comprehensive Income as appropriate, until recognized as operating income in the Company s Consolidated Statements of Operations as the physical production hedged by the contracts is delivered.

We are required to assess the effectiveness of all our derivative contracts at inception and at every quarter-end. If open contracts cease to qualify for hedge accounting, mark-to-market accounting is utilized and changes in the fair value of open contracts are recognized in the Consolidated Statements of Operations. Not qualifying for hedge accounting may cause volatility in Net Income. Fair value is assessed, measured and estimated by obtaining forward commodity pricing, credit adjusted risk-free interest rates and estimated volatility factors. In addition, forward price curves and estimates of future volatility factors are used to assess and measure the effectiveness of our open contracts at the end of each period. The fair values we report in our Consolidated Financial Statements change as estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

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 the Company to price risk; (ii) the derivative reduces the risk exposure and

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2007, 2006 and 2005

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.

Financial Instruments The Company s financial instruments consist of cash and cash equivalents, restricted cash, receivables, derivatives, payables and outstanding debt comprised of a bank credit facility and unsecured senior notes. The carrying amount of the Company s financial instruments approximate fair value due to the short-term nature of these investments. The carrying amount of our bank credit facility approximates fair value as the interest rates are indexed to current market rates. The carrying amount of our unsecured senior notes approximate fair value as the interest rates are fixed.

Revenue Recognition Our natural gas, crude oil and natural gas liquids (NGLs) revenues are recorded using the entitlement method. Under the entitlement method, revenue is recorded when title passes based on the Company s net interest or nominated deliveries. The Company records its entitled share of revenues based on entitled volumes and contracted sales prices. The sales price for natural gas, crude oil and NGLs are adjusted for revenue deductions. The revenue deductions are based on contractual or historical data and do not require significant judgment. Subsequently, these revenue deductions are adjusted to reflect actual charges based on third party documents. Historically, these adjustments have been insignificant. Since there is a ready market for natural gas, crude oil and NGLs, the Company sells the majority of its products soon after production at various locations at which time title and risk of loss pass to the buyer. As a result, the Company maintains a minimum amount of product inventory in storage.

Gas imbalances occur when Mariner sells more or less than its entitled ownership percentage of total gas production. Any amount received in excess (overproduction) of Mariner s share is treated as a liability. If Mariner receives less than it is entitled, the shortage (underproduction) is recorded as a receivable. Imbalances are reduced either by subsequent recoupment of over-and-under deliveries or by cash settlement, as required by applicable contracts. Production imbalances are marked-to-market at the end of each month at the lowest of (i) the price in effect at the time of production, (ii) the current market price or (iii) the contract price, if a contract exists. Mariner s gas imbalances are not material, as oil and natural gas volumes sold are not significantly different from its share of production.

Other revenues are primarily processing fees earned by the Spraberry Aldwell processing plant in West Texas.

Concentration of Credit Risk We extend credit, primarily in the form of uncollateralized oil and gas sales and joint interest owners receivables, to various companies in the oil and gas industry, which results in a concentration of credit risk. The concentration of credit risk may be affected by changes in economic or other conditions within our industry and may accordingly impact our overall credit risk. However, we believe that the risk of these unsecured receivables is mitigated by the size, reputation, and nature of the companies to which we extend credit.

Operating Costs We classify our operating costs as lease operating expense, severance and ad valorem taxes, transportation expense and general and administrative expense. Lease operating expense is 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, workovers and the costs associated with production handling agreements for most of our deepwater

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fields. Lease operating expense also includes indirect costs such as oil and gas property insurance and overhead allocations in accordance with joint operating agreements.

Severance and ad valorem taxes are comprised of severance, production and ad valorem taxes and are generally variable costs based on production, except for ad valorem taxes.

Transportation expense includes variable costs associated with transportation of product to sales meters from the wellhead or field gathering point.

General and administrative expense includes employee compensation costs (including share-based 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.

General and Administrative Expense Under the full-cost method of accounting, a portion of our general and administrative expenses that are directly attributable to our acquisition, exploration and development activities are capitalized as part of our full-cost pool. We capitalized general and administrative costs related to our acquisition, exploration and development activities of approximately $14.0 million for 2007, $11.0 million for 2006, and $5.3 million for 2005. Share-based compensation expense is classified with general and administrative expenses. See Note 5. Stockholders Equity for further discussion on share-based compensation expense.

We receive reimbursement for administrative and overhead expenses incurred on behalf of other working interest owners on properties we operate. These reimbursements totaling $12.5 million, $16.7 million and $6.9 million for the years ended December 31, 2007, 2006 and 2005, respectively, were allocated as reductions to general and administrative expenses incurred. Generally, we do not receive any reimbursements or fees in excess of the costs incurred; however, if we did, we would credit the excess to the full-cost pool to be recognized through lower cost amortization as production occurs.

Accounting for Stock Options and Restricted Stock The Company adopted SFAS No. 123(R), Share-Based Payment (SFAS 123(R)) using the modified retrospective application effective January 1, 2005. As a result of the adoption of SFAS 123(R), we record share-based compensation expense for the fair value of restricted stock granted under our various equity plans, (Refer to Note 5. Stockholders Equity in these Notes to the Consolidated Financial Statements.) We determine share-based compensation expense for the restricted stock grants equal to their fair value at the date of grant. The fair value will then be amortized to share-based compensation expense over the applicable vesting period. Share-based compensation expense is included with general and administrative expenses on the Consolidated Statements of Operations.

Capitalized Interest Costs The Company capitalizes interest based on the cost of major development projects, which are excluded from current depreciation, depletion, and amortization calculations. Capitalized interest costs were approximately $0.5 million for 2007, $1.5 million for 2006, and $0.7 million for 2005.

Reclassifications and Use of Estimates in the Preparation of Financial Statements Some amounts from the previous years have been reclassified to conform to the 2007 presentation of financial statements. These reclassifications do not affect net income.

The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America (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.

Principles of Consolidation The Consolidated Financial Statements include our accounts and those of our subsidiaries. All intercompany transactions are eliminated upon consolidation.

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Net Income per Share Basic earnings per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding during the period. Fully diluted earnings per share assumes the conversion of all potentially dilutive securities and is calculated by dividing net income by the sum of the weighted average number of shares of common stock outstanding plus all potentially dilutive securities.

Effective March 3, 2005, we effected a stock split increasing our authorized shares from 2,000,000 to 70,000,000 and our outstanding shares from 1,380 to 29,748,130. We also changed the stated par value of our stock from $1 to $.0001 per share. The accompanying financial and earnings per share information has been restated utilizing the post-split shares.

Outstanding restricted stock and unexercised stock options diluted earnings by $0.01 per share for both years ended December 31, 2007 and 2006, respectively.

Comprehensive Income Comprehensive income includes net income and certain items recorded directly to stockholder s equity and classified as other comprehensive income. The table below summarizes comprehensive income and provides the components of the change in accumulated other comprehensive income for years ended December 31, 2007, 2006 and 2005:

	Years Ended December 31, 2007	2006 (In thousands)	2005
Net Income	$ 143,934	$ 121,462	$ 40,481
Other comprehensive income (loss), net of tax:			
Derivative contracts settled and reclassified, net of tax	29,262	21,431	32,035
Change in unrealized mark-to-market gains/(losses) arising during period, net of tax	(94,935)	63,139	(61,878)
Change in accumulated other comprehensive income (loss)	(65,673)	84,570	(29,843)
Comprehensive income	$ 78,261	$ 206,032	$ 10,638

Major Customers During the year ended December 31, 2007, sales of oil and gas to our three highest purchasers accounted for 23%, 10% and 9% of total revenues. During the year ended December 31, 2006, sales of oil and gas to our three highest purchasers accounted for 23%, 14% and 11% of total revenues. During the year ended December 31, 2005, sales of oil and gas to our three highest purchasers accounted for 24%, 10% and 15% of total revenues. Management believes that the loss of any of these purchasers would not have a material impact on the Company s financial condition, results of operations or cash flows.

Percentage of Total

Customer	Revenues for Year Ended December 31, 2007	2006	2005
BP Energy	9%	14%	*
Bridgeline Gas Distributing Company(1)			15%
ChevronTexaco and affiliates(1)	23%	23%	24%
Louis Dreyfus Energy	9%	10%	7%
Plains Marketing LP	7%	11%	10%
Shell	10%	8%	*

(1) Bridgeline Gas Distributing Company is an affiliate of ChevronTexaco

* Less than 1%

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Recent Accounting Pronouncements

In December 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 141(R), Business Combinations (SFAS 141(R)), which replaces SFAS 141. SFAS 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements, which will enable users to evaluate the nature and financial effects of the business combination. SFAS 141(R) is effective for fiscal years beginning after December 15, 2008. The adoption of SFAS 141(R) will have an impact on accounting for business combinations once adopted, but the effect is dependent upon acquisitions at that time.

In December 2007, FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of Accounting Research Bulletin No. 51 (SFAS 160), which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent s ownership interest and the valuation of retained non-controlling equity investments when a subsidiary is deconsolidated. The Statement also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. SFAS 160 is effective for fiscal years beginning after December 15, 2008. The Company has not determined the effect that the application of SFAS 160 will have on its Consolidated Financial Statements.

In April 2007, FASB issued FASB Interpretation No. 39-1, Amendment of FASB Interpretation No. 39 (FIN 39-1), which addresses certain modifications to FASB Interpretation No. 39, Offsetting of Amounts Related to Certain Contracts, and whether a reporting entity that is party to a master netting arrangement can offset fair value amounts recognized for the right to reclaim or obligation to return cash collateral against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement in accordance with Interpretation 39. FIN 39-1 is effective for fiscal years beginning after November 15, 2007, with early application permitted. We are evaluating the impact that FIN 39-1 will have on our Consolidated Financial Statements.

During February 2007, FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (SFAS 159), which permits all entities to choose, at specified election dates, to measure eligible items at fair value. SFAS 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value, and thereby mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. This Statement also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS 159 is effective as of the beginning of an entity s first fiscal year that begins after November 15, 2007. We are evaluating the impact that this standard will have on our consolidated financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS 157), which establishes guidelines for measuring fair value and expands disclosures regarding fair value measurements. SFAS 157 does not require any new fair value measurements but rather it eliminates inconsistencies in the guidance found in various prior accounting pronouncements. SFAS 157 is effective for fiscal years beginning after November 15, 2007. Earlier adoption is encouraged, provided the company has not yet issued financial statements, including for interim periods, for that fiscal year. We are evaluating the impact that this standard will have on our consolidated financial position, results of operations or cash flows.

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Note 2. Related Party Transactions

Organization and Ownership of the Company

On February 10, 2005, in anticipation of the private placement by the Company and its sole stockholder of an aggregate 31,452,500 shares of the Company s common stock in March 2005 (the Private Equity Placement), the Company s former parent companies were merged into the Company and ceased to exist. The mergers had no operational or financial impact on the Company; however, intercompany receivables of $0.2 million and $2.9 million in cash held by the affiliates were transferred to the Company in February 2005 and accounted for as additional paid in capital. In the Private Equity Placement, the Company sold 16,350,000 shares of its common stock and its sole stockholder sold 15,102,500 shares of the Company s common stock. The Company s net proceeds in the Private Equity Placement were $212.9 million, before offering costs of $2.2 million, of which $166.0 million was paid to its sole stockholder to redeem 12,750,000 shares of the Company s common stock in March 2005.

In March 2004, the Company was acquired in a merger by an affiliate of two unrelated private equity funds. The Company then became obligated to make payments under management agreements and monitoring agreements with affiliates of these private equity funds. In February 2005, the monitoring agreements were terminated in consideration of payments by the Company of an aggregate $2.3 million. No obligations under the management and monitoring agreements continued after February 2005.

Note 3. Acquisitions and Dispositions

West Texas Acquisition. On December 31, 2007, Mariner acquired additional working interests in certain of its existing properties in the Spraberry field in the Permian Basin. Ryder Scott Company, L.P. estimated net proved oil and gas reserves attributable to the acquisition of approximately 95.5 Bcfe (75% oil and NGLs). Mariner intends to operate substantially all of the assets. Mariner financed the purchase price of approximately $122.5 million under its bank credit facility.

Interest in Cottonwood On December 1, 2006, we sold our 20% interest in the Garden Banks 244 (Cottonwood) project to Petrobras America, Inc., for $31.8 million. The sale was effective November 1, 2006 and represented approximately 6.6 Bcfe of estimated proved reserves. Proceeds from the sale were deposited in trust with a qualified intermediary to preserve our ability to reinvest them in a tax-deferred, like-kind exchange transaction for federal income tax purposes. Inasmuch as we elected not to identify replacement like-kind property to facilitate the exchange, proceeds and related interest totaling $32.0 million were disbursed to us on January 19, 2007 and used to repay borrowings under our bank credit facility. No gain was recorded for book purposes on this disposition.

West Cameron 110/111 On August 7, 2006, the Company exercised its preferential right to purchase the interest of BP Exploration and Production Inc. (BP) in West Cameron Block 110 and the southeast quadrant of West Cameron Block of 111 in the Gulf of Mexico. BP retained rights to depths below 15,000 feet. The acquisition cost was $70.9 million, which was financed by borrowing under our bank credit facility. A $10.4 million letter of credit under our bank credit facility was also issued in favor of BP to secure plugging and abandonment liabilities.

Forest Gulf of Mexico Operations On March 2, 2006, a subsidiary of the Company completed a merger transaction with Forest Energy Resources, Inc. (the Forest Merger). Prior to the consummation of the Forest Merger, Forest Oil Corporation (Forest) transferred and contributed the assets of, and certain liabilities associated with, its offshore Gulf of Mexico operations to Forest Energy Resources, Inc. Immediately prior to the Forest Merger, Forest distributed all of the outstanding shares of Forest Energy Resources, Inc. to Forest stockholders on a pro rata basis. Forest Energy Resources, Inc. then merged with a newly formed subsidiary of Mariner, became a new wholly owned subsidiary of Mariner and changed its name to Mariner Energy Resources, Inc. (MERI). Immediately following the Forest Merger, approximately 59% of the Mariner

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common stock was held by stockholders of Forest and approximately 41% of Mariner common stock was held by the pre-merger stockholders of Mariner.

To acquire MERI, Mariner issued 50,637,010 shares of its common stock to the stockholders of Forest Energy Resources, Inc. The aggregate consideration was valued at $890.0 million, comprised of $3.8 million in pre-merger costs and $886.2 million in common stock, based on the closing price of the Company s common stock of $17.50 per share on September 12, 2005 (which was the date that the terms of the acquisition were announced).

The Forest Merger was accounted for using the purchase method of accounting under the accounting standards established in SFAS 141, Business Combinations and SFAS 142, Goodwill and Other Intangible Assets. As a result, the assets and liabilities acquired by Mariner in the Forest Merger are included in the Company s December 31, 2006 Consolidated Balance Sheet. The Company reflected the results of operations of the Forest Merger beginning March 2, 2006. The Company recorded the estimated fair values of the assets acquired and liabilities assumed at the March 2, 2006 closing date, which are summarized in the following table:

	(In millions)
Oil and natural gas properties	$ 1,211.4
Abandonment liabilities	(165.2)
Long-term debt	(176.2)
Fair value of oil and natural gas derivatives	(17.5)
Deferred tax liability	(199.4)
Other assets and liabilities	(24.5)
Goodwill	261.4
Net Assets Acquired	$ 890.0

The Forest Merger includes a large undeveloped offshore acreage position, which complements the Company s large seismic database and a large portfolio of potential exploratory prospects. The initial fair value estimate of the underlying assets and liabilities acquired is determined by estimating the value of the underlying proved reserves at the transaction date plus or minus the fair value of other assets and liabilities, including inventory, unproved oil and gas properties, gas imbalances, debt (at face value), derivatives, and abandonment liabilities. The deferred tax liability recognizes the difference between the historical tax basis of the assets of Forest Energy Resources, Inc. and the acquisition cost recorded for book purposes. Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed in the acquisition. The entire goodwill balance is non-deductible for tax purposes.

The purchase price allocation has been finalized. In 2006, we recorded a $27.1 million goodwill adjustment primarily related to insurance receivables and deferred taxes. In April 2006, Mariner made a preliminary cash payment to Forest of $20.8 million recorded as an offset to current liabilities. Carryover basis accounting applies for tax purposes.

On March 2, 2006, Mariner and MERI entered into a $500 million bank credit facility and an additional $40 million senior secured Dedicated Letter of Credit. Please refer to Note 4. Long-Term Debt for further discussion of the amended and restated bank credit facility.

Pro Forma Financial Information The pro forma information set forth below gives effect to the Forest Merger as if it had been consummated as of the beginning of the applicable period. The Forest Merger was consummated on March 2, 2006. The pro forma information has been derived from the historical Consolidated Financial Statements of the Company and the statements of revenues and direct operating expenses of the Forest Gulf of Mexico operations. The pro forma information is for illustrative purposes only. The financial

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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 pro forma financial information as being indicative of the historical results that would have been achieved had the Forest Merger occurred in the past or the future financial results that the Company will achieve after the Forest Merger.

	Year Ended December 31, 2006		Year Ended December 31, 2005	
	(Unaudited) (In thousands, except per share amounts)			
Pro Forma:				
Revenue	$	725,321	$	591,982
Net income available to common stockholders	$	134,428	$	57,952
Basic earnings per share	$	1.76	$	0.70
Diluted earnings per share	$	1.75	$	0.69

Note 4. Long-Term Debt

Bank Credit Facility On March 2, 2004, the Company obtained a revolving line of credit subject to a borrowing base. The borrowing base is based upon the evaluation by the lenders of the Company s oil and gas reserves and other factors. Any increase in the borrowing base requires the consent of all lenders. Substantially all of the Company s assets are pledged to secure the bank credit facility.

In connection with the Forest Merger, the Company amended and restated its existing bank credit facility on March 2, 2006 to, among other things, increase maximum credit availability to $500 million for revolving loans, including up to $50 million in letters of credit, with a $400 million borrowing base as of that date; add an additional dedicated $40 million letter of credit that did not affect the borrowing base (the Dedicated Letter of Credit); and add MERI as a co-borrower. As further amended, the bank credit facility will mature on January 31, 2012. The Company used borrowings under its bank credit facility to facilitate the Forest Merger and to retire existing debt, and it may use borrowings in the future for general corporate purposes.

The Dedicated Letter of Credit was obtained in favor of Forest to secure the Company s performance of its obligations to drill and complete 150 wells under a drill-to-earn program and was not included as a use of the borrowing base. The Dedicated Letter of Credit reduced periodically by an amount equal to the product of $0.5 million times the number of wells exceeding 75 that were drilled and completed. As of December 31, 2007, the Company drilled and completed all 150 wells under the program and the Dedicated Letter of Credit was cancelled in January 2008. The Dedicated Letter of Credit balance as of December 31, 2007 was $3.2 million.

On April 23, 2007, the Company s secured bank credit facility was further amended to increase from $350 million to $600 million the aggregate principal amount of certain unsecured bonds that the Company may issue with a non-default interest rate of 10% or less per annum and a scheduled maturity date after March 1, 2012. The amendment provided that upon a new bond issuance of up to $300 million before May 1, 2007, the borrowing base under the credit facility would remain at its then current level of $450 million, subject to redetermination or adjustment under the credit agreement. Accordingly, the borrowing base was reaffirmed at $450 million upon the April 30, 2007 issuance by the Company of its 8% Senior Notes due 2017 discussed below.

In December 2007, the borrowing base was reaffirmed at $450 million and in January 2008, increased to $750 million. As of December 31, 2007 and 2006, $179 million and $354.0 million, respectively, were outstanding under the bank credit facility, and the interest rate was 7.25% and 7.29%, respectively. In addition, four letters of credit totaling $4.7 million (excluding the Dedicated Letter of Credit) were outstanding, of

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which $4.2 million is required for plugging and abandonment obligations at certain of the Company s offshore fields. The outstanding principal balance of loans under the bank credit facility may not exceed the borrowing base. If the borrowing base falls below the sum of the amount borrowed and uncollateralized letter of credit exposure, then to the extent of the deficit, the Company must prepay borrowings and cash collateralize letter of credit exposure, pledge additional unencumbered collateral, repay borrowings and cash collateralize letters of credit on an installment basis, or effect some combination of these actions.

The bank credit facility contains various restrictive covenants and other usual and customary terms and conditions, including limitations on the payment of cash dividends and other restricted payments, the incurrence of additional debt, the sale of assets and speculative hedging. The financial covenants under the bank credit facility require the Company to, among other things:

maintain a ratio of consolidated current assets plus the unused borrowing base to consolidated current liabilities of not less than 1.0 to 1.0; and

maintain a ratio of total debt to EBITDA, as defined in the credit agreement, of not more than 2.5 to 1.0.

The Company was in compliance with the financial covenants under the bank credit facility as of December 31, 2007.

The Company must pay a commitment fee of 0.250% to 0.375% per year on the unused availability under the bank credit facility.

Senior Notes On April 24, 2006, the Company sold and issued to eligible purchasers $300 million aggregate principal amount of its 71/2% Senior Notes due 2013 (the 71/2% Notes) pursuant to Rule 144A under the Securities Act of 1933, as amended. The 71/2% Notes were priced to yield 7.75% to maturity. Net proceeds, after deducting initial purchasers discounts and commissions and offering expenses, were approximately $287.9 million. Mariner used the net proceeds of the offering to repay debt under the bank credit facility. On November 9, 2006, the Company replaced the original Notes issued in the private placement with new Notes with identical terms and tenor through an exchange offer registered under the Securities Act of 1933.

On April 30, 2007, the Company sold and issued $300 million aggregate principal amount of its 8% Senior Notes due 2017 (the 8% Notes and together with the 71/2% Notes, the Notes). The 8% Notes were sold at par in an underwritten offering registered under the Securities Act of 1933. Net offering proceeds, after deducting underwriters discounts and offering expenses, were approximately $293.4 million. The Company used the net offering proceeds to repay debt under its bank credit facility.

The Notes are senior unsecured obligations of the Company, rank senior in right of payment to any future subordinated indebtedness, rank equally in right of payment with each other and with the Company s existing and future senior unsecured indebtedness, and are effectively subordinated in right of payment to the Company s senior secured indebtedness, including its obligations under its bank credit facility, to the extent of the collateral securing such indebtedness, and to all existing and future indebtedness and other liabilities of any non-guarantor subsidiaries.

The Notes are jointly and severally guaranteed on a senior unsecured basis by the Company s existing and future domestic subsidiaries. In the future, the guarantees may be released or terminated under certain circumstances. Each subsidiary guarantee ranks senior in right of payment to any future subordinated indebtedness of the guarantor subsidiary, ranks equally in right of payment to all existing and future senior unsecured indebtedness of the guarantor subsidiary and effectively subordinate to all existing and future secured indebtedness of the guarantor subsidiary, including its guarantees of indebtedness under the Company s bank credit facility, to the extent of the collateral securing such indebtedness.

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Interest on the 71/2% Notes is payable on April 15 and October 15 of each year. The 71/2% Notes mature on April 15, 2013. Interest on the 8% Notes is payable on May 15 and November 15 of each year, beginning November 15, 2007. The 8% Notes mature on May 15, 2017. There is no sinking fund for the Notes.

The Company may redeem the 71/2% Notes at any time before April 15, 2010 and the 8% Notes at any time before May 15, 2012, in each case at a price equal to the principal amount redeemed plus a make-whole premium, using a discount rate of the Treasury rate plus 0.50% and accrued but unpaid interest. Beginning on the dates indicated below, the Company may redeem the Notes from time to time, in whole or in part, at the prices set forth below (expressed as percentages of the principal amount redeemed) plus accrued but unpaid interest:

71/2% Notes	8% Notes
April 15, 2010 at 103.750%	May 15, 2012 at 104.000%
April 15, 2011 at 101.875%	May 15, 2013 at 102.667%
April 15, 2012 and thereafter at 100.000%	May 15, 2014 at 101.333%
	May 15, 2015 and thereafter at 100.000%

In addition, before April 15, 2009, the Company may redeem up to 35% of the 71/2% Notes with the proceeds of equity offerings at a price equal to 107.50% of the principal amount of the 71/2% Notes redeemed. Before May 15, 2010, the Company may redeem up to 35% of the 8% Notes with the proceeds of equity offerings at a price equal to 108% of the principal amount of the 8% Notes redeemed plus accrued but unpaid interest.

If the Company experiences a change of control (as defined in each of the indentures governing the Notes), subject to certain exceptions, the Company must give holders of the Notes the opportunity to sell to the Company their Notes, in whole or in part, at a purchase price equal to 101% of the principal amount, plus accrued and unpaid interest and liquidated damages to the date of purchase.

The Company and its restricted subsidiaries are subject to certain negative covenants under each of the indentures governing the Notes. The indentures limit the ability of the Company and each of its restricted subsidiaries to, among other things:

- make investments;
- incur additional indebtedness or issue preferred stock;
- create certain liens;
- sell assets;
- enter into agreements that restrict dividends or other payments from its subsidiaries to itself;
- consolidate, merge or transfer all or substantially all of its assets;

engage in transactions with affiliates;

pay dividends or make other distributions on capital stock or subordinated indebtedness; and

create unrestricted subsidiaries.

Costs associated with the 71/2% Notes offering were approximately $8.5 million, excluding discounts of $3.8 million. Costs associated with the 8% Notes offering included aggregate underwriting discounts of approximately $5.3 million and offering expenses of approximately $1.3 million.

Term Promissory Note On March 2, 2004, the Company issued a $10 million term promissory note to a former affiliate as a part of consideration in a merger that resulted in the affiliate s disposition of its ownership interest in the Company s indirect parent. The note matured on March 2, 2006, and bore interest, payable in kind at our option, at a rate of 10% per annum until March 2, 2005, and 12% per annum thereafter

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unless paid in cash in which event the rate remained 10% per annum. We chose to pay interest in cash rather than in kind. In March 2005, the Company repaid $6.0 million of the note utilizing proceeds from the Private Equity Placement. The $4.0 million balance remaining on the note was repaid in full on its maturity date of March 2, 2006.

Capitalized Interest For the period ended December 31, 2007 and 2006, capitalized interest totaled $0.5 million and $1.5 million, respectively.

Cash Interest Expense For the years ended December 31, 2007, 2006, and 2005 interest payments were $49.1 million, $28.8 million, and $6.1 million, respectively.

Bank Debt Issuance Costs The Company capitalizes certain direct costs associated with the issuance of long-term debt. In conjunction with the Forest Merger, the Company s bank credit facility was amended and restated to, among other things, increase the borrowing capacity from $185 million to $400 million, based upon an initial borrowing base of that amount. The amendment and restatement was treated as an extinguishment of debt for accounting purposes. This treatment resulted in a charge of approximately $1.2 million in the first quarter of 2006. This charge is included in the interest expense line of the Consolidated Statements of Operations.

Note 5. Stockholders Equity

Increase in Number of Shares Authorized On March 2, 2006, the Company s certificate of incorporation was amended to increase its authorized stock to 200,000,000 shares, of which 180,000,000 shares are common stock and 20,000,000 shares are preferred stock.

Equity Participation Plan We adopted an Equity Participation Plan, as amended, that provided for the one-time grant at the closing of our Private Equity Placement on March 11, 2005 of 2,267,270 restricted shares of our common stock to certain of our employees. No further grants will be made under the Equity Participation Plan, although persons who received such a grant are eligible for future awards of restricted stock or stock options under our Stock Incentive Plan, as amended or restated from time to time, described below. We intended the grants of restricted stock under the Equity Participation Plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of our common stock. Therefore, Equity Participation Plan grantees did not pay any consideration for the common stock they received, and we received no remuneration for the stock. As a result of closing the Forest Merger, all shares of restricted stock granted under the Equity Participation Plan vested as follows: (i) the 463,656 shares of restricted stock held by non-executive employees vested on March 2, 2006, and (ii) the 1,803,614 shares of restricted stock held by executive officers vested on May 31, 2006 pursuant to an agreement, made in exchange for a cash payment of $1,000 to each officer, that his or her shares of restricted stock would not vest before the later of March 11, 2006 or ninety days after the effective date of the Forest Merger. The Equity Participation Plan expired upon the vesting of all shares granted thereunder. Stock could be withheld by us upon vesting to satisfy our tax withholding obligations with respect to the vesting of the restricted stock. Participants in the Equity Participation Plan had the right to elect to have us withhold and cancel shares of the restricted stock to satisfy our tax withholding obligations. In such events, we would be required to pay any tax withholding obligation in cash. In 2006, as a result of such participant elections, we withheld an aggregate 807,376 shares that otherwise would have remained outstanding upon vesting of the restricted stock, reducing the aggregate outstanding vested stock grants made under the Equity Participation Plan to 1,459,894 shares. The 807,376 shares withheld became treasury shares that were retired and restored to the status of authorized and unissued shares of common stock, and the Company s capital was reduced by an amount equal to the $.0001 par value of the retired shares. We paid in cash the associated withholding taxes of $14.0 million, of which $3.3 million and $10.7 million were paid in the first and second quarter of 2006, respectively.

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Stock Incentive Plan We adopted a Stock Incentive Plan that became effective March 11, 2005, was amended and restated on March 2, 2006, further amended on March 16, 2006, and amended and restated on February 6, 2007. Awards to participants under the Stock Incentive Plan may be made in the form of incentive stock options or ISOs, non-qualified stock options or restricted stock. The participants to whom awards are granted, the type or types of awards granted to a participant, the number of shares covered by each award, and the purchase price, conditions and other terms of each award are determined by the Board of Directors or a committee thereof. A total of 6,500,000 shares of Mariner s common stock are subject to the Stock Incentive Plan. No more than 2,850,000 shares issuable upon exercise of options or as restricted stock can be issued to any individual. Unless sooner terminated, no award may be granted under the Stock Incentive Plan after October 12, 2015.

During the years ended December 31, 2007 and 2006, we granted 906,104 and 907,371 shares, respectively, of restricted common stock under the Stock Incentive Plan. As of December 31, 2007, no stock options had been granted under the Stock Incentive Plan since the year ended December 31, 2005, during which we granted options to purchase 809,000 shares of common stock thereunder. Under the Stock Incentive Plan as of December 31, 2007, 1,484,552 shares of unvested restricted common stock remained outstanding and there were options exercisable for 669,805 shares of common stock, of which 488,474 were presently exercisable and 181,331 are expected to vest in March 2008. As of December 31, 2007, 4,072,801 shares remained available for future issuance to participants under the Stock Incentive Plan.

During the years ended December 31, 2007 and 2006, 251,332 and 4,500 shares, respectively, of restricted stock vested under the Stock Incentive Plan, resulting in withholding tax obligations. Plan participants can elect to have us withhold and cancel shares of restricted stock to satisfy the associated tax withholding obligations. In such event, we would be required to pay any tax withholding obligation in cash. As a result of such participant elections, we withheld an aggregate 71,173 and 532 shares in the years ended December 31, 2007 and 2006, respectively, that otherwise would have remained outstanding upon vesting of the restricted stock. The shares withheld became treasury shares that were retired and restored to the status of authorized and unissued shares of common stock, and the Company s capital was reduced by an amount equal to the $.0001 par value of the retired shares. We paid in cash the associated withholding taxes of approximately $829,000 and $10,000 for the years ended December 31, 2007 and 2006, respectively.

Rollover Options In connection with the Forest Merger and during the year ended December 31, 2006, the Company granted options to acquire 156,626 shares of its common stock to certain former employees of Forest or Forest Energy Resources, Inc. (Rollover Options). The Rollover Options are evidenced by non-qualified stock option agreements and are not covered by the Stock Incentive Plan. As of December 31, 2007, Rollover Options to purchase 50,683 shares of the Company s common stock remained outstanding, of which 25,864 were presently exercisable, and 24,819 were unvested.

Accounting for Stock Options and Restricted Stock The Company adopted SFAS 123(R) Share-Based Payment , using the modified retrospective application effective January 1, 2005. As a result of the adoption of SFAS 123(R), we recorded share-based compensation expense for the fair value of restricted stock that was granted pursuant to our Equity Participation Plan. We also record share-based compensation expense for the value of restricted stock and options granted under the Stock Incentive Plan and Rollover Options. In general, share-based compensation expense is determined at the date of grant based on the fair value of the stock or options granted. The fair value is amortized to share-based compensation expense over the applicable vesting period. We recorded share-based compensation expense of $10.9 million and $10.2 million for the periods ended December 31, 2007 and 2006, respectively, related to restricted stock grants in 2007, 2006 and 2005 and stock options outstanding for the periods then ended. As of May 31, 2006, the participants were fully vested in the restricted stock granted under the Equity Participation Plan and no unrecognized compensation remains. Under the Stock Incentive Plan, unrecognized compensation expense at December 31, 2007 for the unvested portion of restricted stock granted was $26.2 million and for unvested options was $0.7 million.

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The following table presents a summary of stock option activity, inclusive of the stock options under the Stock Incentive Plan and the Rollover Options, for the year ended December 31, 2007:

	Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value(1) ($000)
Outstanding at beginning of year January 1, 2007	802,322	$ 13.77	$ 4,678
Granted			
Exercised	(64,141)	$ 12.92	
Forfeited(2)	(17,693)		
Outstanding at end of year December 31, 2007	720,488	$ 13.82	$ 6,526
Vested and expected to vest	702,779	$ 13.88	$ 6,323
Exercisable at end of year	514,338	$ 13.88	$ 4,629
Available for future grant as options or restricted stock	4,072,801		

(1) Based upon the difference between the market price of the common stock on the last trading date of the year ($22.88) and the option exercise price of in-the-money options.

(2) Rollover Options exercisable for 17,693 shares were forfeited due to terminations of employment, but may not be indicative of a historical forfeiture rate.

For the year ended December 31, 2007, 64,141 options were exercised resulting in an increase of cash by approximately $829,000 and a windfall tax deduction of approximately $421,000 in excess of previously recorded tax benefits, based on the option value at the time of grant. The windfalls are reflected in net operating tax carry forwards pursuant to SFAS 123(R), but the additional tax benefit associated with the windfall is not recognized until the deduction reduces taxes payable.

The following table summarizes certain information about stock options outstanding under the Stock Incentive Plan and the Rollover Options at December 31, 2007:

	Options Outstanding		Options Exercisable	
Exercise Price	Shares Outstanding	Weighted Average Remaining Contractual	Expected Term	Weighted Average Shares Exercisable

		Life (Years)		
$9.48	1,981	7.98	6.15	
$9.67	660	7.92	6.08	
$11.44	4,952	8.67	6.88	3,302
$11.59	43,090	8.75	6.94	22,562
$14.00	669,805	7.29	10.50	488,474
Total number of shares	720,488			514,338

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The following table summarizes certain information about stock options outstanding under the Stock Incentive Plan and the Rollover Options at December 31, 2006:

Exercise Price	Options Outstanding Shares Outstanding	Options Outstanding Weighted Average Remaining Contractual Life (Years)	Expected Term	Options Exercisable Weighted Average Shares Exercisable
$8.81	1,056	6.16	6.00	
$9.48	5,283	7.15	6.00	
$9.67	1,321	7.08	6.00	
$11.44	4,952	7.88	6.00	1,651
$11.59	71,226	7.94	6.00	23,173
$14.00	706,880	8.31	6.00	347,216
$15.50				(3,000)
$16.86	10,564	8.62	6.00	2,641
$17.00	1,040	8.72	6.00	1,040
Total number of shares	802,322			372,721

The following table summarizes certain information about stock options outstanding at December 31, 2005:

Range of Exercise Prices	Options Outstanding Number Outstanding	Options Outstanding Weighted Average Remaining Contractual Life (Years)	Options Outstanding Weighted Average Exercise Price	Options Exercisable Number Exercisable	Options Exercisable Weighted Average Exercise Price
$14.00 $17.00	809,000	9.5	$ 14.02		

Options generally vest over one to three-year periods and are exercisable for periods ranging from seven to ten years. The weighted average fair value of options granted during 2006 and 2005 was $2.58 and $2.69, respectively. There were no options granted during 2007. The fair value of each option award is estimated on the date of grant using the Black-Scholes option valuation model. The assumptions utilized in 2007, 2006 and 2005 are noted in the following table:

	12 Months Ended December 31,			
	2007	2006		2005
Black-Scholes Assumptions	**Stock Incentive Plan Options(2)**	**Stock Incentive Plan Options(1)**	**Rollover Options**	**Stock Incentive Plan Options(2)**
Expected Term (years)	6.0	6.0	4.7	3.0
Risk Free Interest Rate	4.80%	4.80%	4.79%	3.79%
Expected Volatility	35.00%	35.00%	35.00%	38.00%
Dividend Yield	0.00%	0.00%	0.00%	0.00%

(1) Stock Incentive Plan as amended and restated

(2) There were no Rollover Options in 2007 or 2005

The expected term (estimated period of time outstanding) of options granted was determined by averaging the vesting period and contractual term. The expected volatility was based on historical volatility of our peer group s common share price for a period equal to the stock option s expected life. The risk-free rate is based

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on the U.S. Treasury-bill rate in effect at the time of grant. The dividend yield is based on the Company s ability to pay dividends.

The following table shows a summary of the activity for unvested restricted stock awards under the Stock Incentive Plan during the years 2007, 2006 and 2005.

	Restricted Shares under the Amended and Restated Stock Incentive Plan		
	2007	**2006**	**2005**
Total unvested shares at beginning of period: January 1	875,380		
Shares granted	906,104	907,371	
Shares vested	(251,332)	(4,500)	
Shares forfeited	(45,600)	(27,491)	
Total unvested shares at end of period: December 31	1,484,552	875,380	
Total shares vested at end of period: December 31	255,832	4,500	
Available for future grant as options or restricted stock	4,072,801	4,862,132	
Average fair value of shares granted during the period	$ 21.73	$ 19.54	$

The following table is a summary of the activity for unvested restricted stock awards under the Equity Participation Plan during the years 2006 and 2005. The Equity Participation Plan was fully vested as of December 31, 2006.

	Restricted Shares under the Equity Participation Plan	
	2006	**2005**
Total unvested shares at beginning of period: January 1	2,267,270	
Shares granted		2,267,270
Shares vested	(2,267,270)	
Shares forfeited		
Total unvested shares at end of period: December 31		2,267,270
Total shares vested at end of period: December 31	2,267,270	
Available for future grant under Equity Participation Plan		
Average fair value of shares granted during the period	$	$ 14.00

Private Equity Placement. In March 2005, the Company sold and issued 16,350,000 shares of its common stock in the Private Equity Placement for net proceeds of $212.9 million, before offering expenses of $2.2 million, of which

$166.0 million were used to redeem 12,750,000 shares of the Company s common stock from its sole stockholder.

Note 6. Employee Benefit and Royalty Plans

Employee Capital Accumulation Plan The Company provides all full-time employees (who are at least 18 years of age) participation in the Employee Capital Accumulation Plan (the Plan), which is comprised of a contributory 401(k) savings plan and a discretionary profit sharing plan. Under the 401(k) feature, the Company, at its sole discretion, may contribute an employer-matching contribution equal to a percentage not to exceed 50% of each eligible participant s matched salary reduction contribution as defined by the Plan. Under the discretionary profit sharing contribution feature of the Plan, the Company s contribution, if any, must be determined annually and must be 4% of the lesser of the Company s operating income or total employee compensation and shall be allocated to each eligible participant pro rata to his or her compensation.

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The Company contributed $945,420 for 2007, $720,426 for 2006, and $240,650 for 2005. Currently there are no plans to terminate the Plan.

Overriding Royalty Interests Pursuant to agreements, certain employees and consultants of the Company are entitled to receive, as incentive compensation, overriding royalty interests (Overriding Royalty Interests) in certain oil and gas prospects acquired by the Company. Such Overriding Royalty Interests entitle the holder to receive a specified percentage of the gross proceeds from the future sale of oil and gas (less production taxes), if any, applicable to the prospects. Cash payments made by the Company to current employees and consultants with respect to Overriding Royalty Interests were $5.8 million for 2007, $2.0 million for 2006, and $2.6 million for 2005.

Note 7. Earnings Per Share

Basic earnings per share does not include dilution and is computed by dividing net income or loss attributed to common stockholders by the weighted-average number of common shares outstanding for the period. Diluted earnings per share reflect the potential dilution that could occur if security interests were exercised or converted into common stock.

The following table sets forth the computation of basic and diluted earnings per share for the years ended December 31, 2007, 2006 and 2005.

	2007			2006			2005		
	Net Income Attributed to Common Stock	Weighted-Average Shares	Per-Share Income/(Loss)	Net Income Attributed to Common Stock	Weighted-Average Shares	Per-Share Income/(Loss)	Net Income Attributed to Common Stock	Weighted-Average Shares	Per-Share Income/(Loss)
	(In thousands, except per share data)								
Basic net income per share	$ 143,934	85,645	$ 1.68	$ 121,462	76,353	$ 1.59	$ 40,481	32,668	$ 1.24
Effect of dilutive securities:		481	(0.01)		458	(0.01)		1,099	(0.04)
Diluted net income earnings per share	$ 143,934	86,126	$ 1.67	$ 121,462	76,811	$ 1.58	$ 40,481	33,767	$ 1.20

Shares issuable upon exercise of options to purchase common stock that would have been anti-dilutive are excluded from the computation of diluted earnings per share. Approximately 513,000 shares issuable upon exercise of stock options were excluded from the computation for year ended December 31, 2007. Approximately 714,000 shares issuable upon exercise of stock options were excluded from the computation for the year ended December 31, 2006.

Effective March 3, 2005, the Company effected a stock split increasing our authorized shares from 2,000,000 to 70,000,000 and our outstanding shares from 1,380 to 29,748,130. The Company also changed the stated par value of the stock from $1.00 to $.0001 per share. The accompanying earnings per share information have been restated utilizing the post-split shares. Effective with the Merger on March 2, 2004, all Company stock option plans and associated outstanding stock options were canceled.

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Note 8. Commitments and Contingencies

Minimum Future Lease Payments The Company leases certain office facilities and other equipment under long-term operating lease arrangements. Minimum future lease obligations under the Company s operating leases in effect at December 31, 2007 are as follows (in thousands):

2008	$ 1,922
2009	2,217
2010	2,489
2011	2,499
2012 and thereafter	14,375
Total	**$ 23,502**

Rental expense, before capitalization, was approximately $1.4 million for 2007, $1.2 million for 2006, and $0.5 million for 2005.

Hedging Program The energy markets have historically been very volatile, and we expect that oil and gas prices will 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 the Company s operations, management has elected to hedge oil and natural gas prices from time to time through the use of commodity price swap agreements and costless collars. While the use of these hedging arrangements limits the downside risk of adverse price movements, it also limits future gains from favorable movements. In addition, forward price curves and estimates of future volatility are used to assess and measure the ineffectiveness of our open contracts at the end of each period. If open contracts cease to qualify for hedge accounting, the mark to market change in fair value is recognized in the Consolidated Statements of Operations. Loss of hedge accounting and cash flow designation will cause volatility in earnings. The fair values we report in our Consolidated Financial Statements change as estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Hedge gains and losses are recorded by commodity type in oil and gas revenues in the Consolidated Statements of Operations. The effects on our oil and gas revenues from our hedging activities were as follows:

	Year Ended December 31,		
	2007	**2006**	**2005(3)**
		(In thousands)	
Cash Gain (Loss) on Settlements	$ 46,732	$ 11,273	$ (53,799)
Gain (Loss) on Hedge Ineffectiveness(1)	(1,655)	4,175	
Non-cash Gain on hedges acquired(2)		17,523	4,515

Total	**$ 45,077**	**$ 32,971**	**$ (49,284)**

(1) Unrealized gain (loss) recognized in natural gas revenue related to the ineffective portion of open contracts that are not eligible for deferral under SFAS 133 Accounting for Derivative Instruments and Hedging Activities , due primarily to the basis differentials between the contract price and the indexed price at the point of sale.

(2) In 2006, relating to the hedges acquired through the Forest transaction.

(3) $4.5 million of the $49.3 million loss relates to the hedge liability associated with the 2004 merger.

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As of December 31, 2007, the Company had the following hedging activity outstanding:

Fixed Price Swaps	Quantity	Weighted-Average Fixed Price	December 31, 2007 Fair Value Gain/(Loss) (In thousands)
Natural Gas (MMBtus)			
January 1 December 31, 2008	40,583,847	$ 8.46	$ 27,672
January 1 December 31, 2009	31,642,084	$ 8.48	(1,494)
Crude Oil (Bbls)			
January 1 December 31, 2008	2,263,552	$ 78.99	(31,219)
January 1 December 31, 2009	2,172,210	$ 76.15	(23,158)
Total			**$ (28,199)**

Costless Collars	Quantity	Floor	Cap	December 31, 2007 Fair Value Gain/(Loss) (In thousands)
Natural Gas (MMBtus)				
January 1 December 31, 2008	12,347,000	$ 7.83	$ 14.60	$ 7,201
Crude Oil (Bbls)				
January 1 December 31, 2008	1,195,495	$ 61.66	$ 86.81	(11,259)
Total				**$ (4,058)**

As of December 31, 2006, the Company had the following hedging activity outstanding:

Fixed Price Swaps	Quantity	Weighted-Average Fixed Price	December 31, 2006 Fair Value Gain (In thousands)

Natural Gas (MMBtus)