MARINER ENERGY INC
Form 10-K/A
March 06, 2009

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

Form 10-K/A
(Amendment No. 1)

þ	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the fiscal year ended December 31, 2008**
	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
Rights to Purchase Preferred Stock	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. þ

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

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, 2008 was approximately $3,166,804,986 based on the closing sale price of $36.97 per share as reported by the New York Stock Exchange on June 30, 2008. The number of shares of common stock of the registrant issued and outstanding on February 20, 2009 was 90,057,276.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of registrant s Proxy Statement relating to the Annual Meeting of Stockholders to be held May 11, 2009 are incorporated by reference into Part III of this Form 10-K.

EXPLANATORY NOTE

The purpose of this Amendment No. 1 on Form 10-K/A (this Form 10-K/A) is to amend Item 8 of Part II of our Annual Report on Form 10-K for the fiscal year ended December 31, 2008, which was filed with the Securities and Exchange Commission (the SEC) on March 2, 2009 (the 2008 10-K). The amendments correct two tables in note 16 (Supplemental Oil and Gas Reserve and Standardized Measure Information (Unaudited)) to the consolidated financial statements. Corrections have been made to the table presenting Estimated Quantities of Proved Reserves and in the table presenting the principal sources of change in the Standardized Measure of discounted future net cash flows. The corrections do not change the total estimated quantities of proved reserves as of December 31, 2008 or the Standardized Measure of discounted future net cash flows as of December 31, 2008 reported in those tables in the 2008 10-K.

In accordance with Rule 12b-15 under the Securities Exchange Act of 1934, as amended (the Exchange Act), this Form 10-K/A amends and restates Item 8 of Part II of the 2008 10-K in its entirety. In addition, as required by Rule 12b-15 under the Exchange Act, new certifications by our principal executive officer and principal financial officer are filed as exhibits to this Form 10-K/A under Item 15 of Part IV.

For ease in preparing our annual report to stockholders under Rule 14a-3 of the Exchange Act, which historically has consisted primarily of our Form 10-K for a given year, this Form 10-K/A restates, without change, Items 1 through 4 of Part I, Items 5 through 7A and 9 through 9B of Part II, and Items 10 through 14 of Part III of the 2008 10-K.

Except as noted above, this Annual Report Form 10-K/A does not reflect events occurring after the filing of the 2008 10-K on March 2, 2009 and no attempt has been made in this Form 10-K/A to modify or update other disclosures made in the 2008 10-K. Accordingly, this Form 10-K/A should be read in conjunction with our filings made with the SEC after the filing of the 2008 10-K.

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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. 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:

Permian Basin, where we are an active driller in the prolific Spraberry field at depths between 6,000 and 10,000 feet. Our increasing Permian Basin 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 Gulf of Mexico deepwater operations. We have expanded our presence in the region, targeting a combination of infill drilling activities in established producing trends, including the Spraberry, Dean and Wolfcamp trends, as well as exploration activities in emerging plays such as the Wolfberry and newer Wolfcamp trends.

Gulf of Mexico Deepwater, 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 84 deepwater wells. Our deepwater exploration operation targets larger potential reserve accumulations than are generally accessible onshore or on the Gulf of Mexico shelf.

Gulf of Mexico Shelf, where we drill or participate in conventional shelf wells and deep shelf wells extending to 1,300 foot water depths. 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 Permian Basin operations, as well as for expansion into new operating areas.

During 2008, we produced approximately 118.4 Bcfe and our average daily production rate was 323 MMcfe per day. At December 31, 2008, we had 973.9 Bcfe of estimated proved reserves, of which approximately 57% were natural gas and 43% were oil, natural gas liquids (NGLs) and condensate. Approximately 70% 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

Gulf of Mexico Deepwater Acquisition On December 19, 2008, we acquired additional working interests in our existing property, Atwater Valley Block 426 (Bass Lite), for approximately $32.6 million, increasing our working interest by 11.6% to 53.8%. We internally estimated proved reserves attributable to the acquisition of approximately 17.6 Bcfe (100% natural gas).

Acquisition of Incremental Spraberry Interests On February 29, 2008 and December 1, 2008, 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 80%. We internally estimated proved reserves attributable to the acquisition of approximately 27.4 Bcfe. We operate substantially all of the assets. The purchase prices were approximately $21.7 million for the February acquisition and $19.4 million for the December acquisition.

Impact of Worldwide Financial Crisis and Lower Commodity Prices on Capital Program

In recent years, oil and gas commodity prices generally trended upwards in response to robust demand and constrained supplies, with oil and gas prices peaking at more than $140.00 per barrel and $13.00 per Mcf, respectively, in July 2008. In response to the sustained increase in commodity prices, the oil and gas industry experienced significant increases in activity and in demand for oil field services. The increased demand for these services resulted in significant inflation in the cost of drilling rigs, services, equipment and labor.

In the second half of 2008, a world-wide economic recession and oversupply of natural gas in North America led to an unprecedented decline in oil and gas prices, with oil falling by more than $100.00 per barrel from its peak earlier in 2008. However, the inflated cost of oil field services resulting from sustained historically high commodity prices did not decrease in line with the decline in commodity prices. The prospect of continued low commodity prices and disproportionately high service costs has constrained the industry s capital reinvestment and undermined rates of return in new projects, particularly those in areas characterized by high costs or long reserve lives. In order to manage our capital program within expected cash flows, we tentatively have reduced our 2009 capital budget by more than 50% from 2008.

Our 2009 activities in the Permian Basin will focus primarily on expanding beyond our typical Spraberry infill drilling operation into new exploration plays, such as the Wolfberry and Wolfcamp Detrital trends. We plan to delineate prospects and determine their economic viability. Our goal is to expand our prospect inventory and generate opportunities to drill when commodity prices or service costs adjust to levels expected to yield more attractive returns. Until then, we are scaling down our infill drilling and development activities to primarily lease-saving operations and contractual drilling commitments. We also anticipate substantially reduced recompletion and development activities in our Gulf of Mexico shelf operation until commodity price and service cost dynamics adjust to allow a more attractive rate of return. In addition, we are allocating a disproportionate portion of our 2009 capital budget to our Gulf of Mexico deepwater exploration program due primarily to contractual drilling commitments.

Balanced Growth Strategy

We are a growth company and strive 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 Gulf of Mexico deepwater 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. 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, allowing 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 the Permian Basin, 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 the Permian Basin and the Gulf of Mexico deepwater and shelf. 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 the Permian Basin, 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.

Large prospect inventory. We believe we have significant potential for growth through the exploration and development of our existing asset base. We are one of the largest leaseholders among independent producers in the Gulf of Mexico. Additionally, we are an active participant at MMS lease sales. We were the apparent high bidder on three blocks at the Outer Continental Shelf 207 Lease Sale held on August 20, 2008 by the MMS. The MMS awarded all three blocks to us, yielding an aggregate exposure of $0.9 million. We hold a 100% working interest in each of these blocks. In addition, the MMS awarded us 19 blocks on which we were the apparent high bidder at the Central Gulf of Mexico Lease Sale 206 held by the MMS on March 19, 2008. The awarded blocks involve seven deepwater subsalt prospects (both Miocene and Lower Tertiary), four deepwater prospects, four deep shelf prospects, and one conventional shelf prospect. Our net exposure on the awarded bids was $79.1 million and our working interest ranges from 33% to 100%. Furthermore, in the Permian Basin 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.

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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, 2008. Our geoscientists each average almost 30 years 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 properties representing approximately 87% of our production and have an average 74% working interest in our operated properties. We believe operating our properties gives us a competitive advantage over non-operating interest holders, particularly in a challenging financial environment, since operatorship better allows us 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.

Properties

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

	Operator	Approximate Working Interest %	2008 Net Production (Bcfe)	Net Estimated Proved Reserves (Bcfe)	Estimated Proved Reserves % Oil /% Gas(1)
Permian Basin:					
Spraberry	Mariner	80%	13.5	419.1	69%/31%
Gulf Of Mexico Deepwater:					
Atwater Valley 426 (Bass Lite)	Mariner	54%	8.5	95.8	0%/100%
Garden Banks 462 (Geauxpher)	Mariner	60%		32.7	3%/97%
Green Canyon 646 (Daniel Boone)	W&T Offshore	40%		18.3	68%/32%
	Anadarko	33-50%	12.9	16.6	34%/66%

East Breaks 558/602 (Northwest Nansen)					
Ewing Bank 921 (North Black Widow)	ENI	35%	1.9	7.8	91%/9%
Gulf Of Mexico Shelf:					
Vermilion 380	Mariner	80%	0.5	33.1	50%/50%
Vermilion 14/26/35	Mariner	100%	1.5	30.1	8%/92%
West Cameron 110	Mariner	100%	4.7	29.3	4%/96%
South Pass 24	Mariner	97%	1.8	21.5	61%/39%
High Island 116	Mariner	100%	0.8	19.5	3%/97%

(1) NGLs are included in Oil

Permian Basin Operations

Our Permian Basin operations historically have emphasized downspacing redevelopment activities in the prolific oil-producing Spraberry field in the Permian Basin. Since we began our Permian Basin redevelopment initiative in 2002, we have increased by approximately five-fold our net acreage position in the related fields and are targeting the Permian Basin for continued expansion through our Permian Basin 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 2008, our Permian Basin operations produced approximately 14.9 Bcfe (13% of our total production) and accounted for approximately 436.6 Bcfe or 45% of our total estimated proved reserves at year end. Oil and NGLs accounted for 73% of total the Permian Basin production for 2008. We drilled 122 wells in the region during 2008 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 the Permian Basin 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 80% working interest. This property consists of net developed and undeveloped acres of 55,989 and 8,907, respectively on which there were 829 wells as of December 31, 2008 producing approximately 13.5 Bcfe net in 2008. This field is located in the Spraberry trend and productive zones in the field include the Spraberry, Dean and Wolfcamp formations. At year-end 2008, our share of estimated proved reserves attributed to this field was 419.1 Bcfe, consisting of 69% oil and 31% natural gas.

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Gulf of Mexico Deepwater Operations

We have acquired and maintained a significant acreage position in the Gulf of Mexico deepwater. 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, 2008, we held interests in 95 deepwater blocks and 40 subsea wells. These wells were tied back to 31 host production facilities for production processing. An additional four 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 Gulf of Mexico deepwater operations is largely from Pleistocene to lower Miocene aged formations and varies between oil and gas depending on formation and age. During 2008, our deepwater operation produced approximately 40.4 Bcfe (34% of our total production) and accounted for approximately 198.7 Bcfe or 20% of our total estimated proved reserves at year end. Natural gas accounted for 69% of total deepwater production for 2008. We drilled eight wells in the region during 2008 with a 63% success rate.

We operate Atwater Valley 426, known as Bass Lite, in which in December 2008 we increased our working interest by 11.6% to 53.8%. 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 and the field produced 8.5 Bcfe net to our interest during 2008. The project commenced production at full capacity once the topside facilities work was completed in August 2008. At year end 2008, our share of estimated proved reserves attributed to this field was 95.8 Bcfe, of which 100% are natural gas.

We operate Garden Banks 462, known as Geauxpher, in which we hold a 60% working interest. We made this deepwater discovery in June 2008. The well, which lies in water depths of approximately 2,700 feet, was drilled to a total depth of 23,156 feet (measured depth). At year-end 2008, our share of estimated proved reserves attributed to the discovery was 32.7 Bcfe, consisting of 3% oil and 97% natural gas. A two-well development is underway, with initial production expected during the first half of 2009. Apache Corporation holds a 40% working interest in the development.

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 2008, our share of estimated proved reserves attributed to this field was 18.3 Bcfe, consisting of 68% oil and 32% 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 and the field produced 12.9 Bcfe net to our interest during 2008. At year end 2008, our share of estimated proved reserves attributed to the field was 16.6 Bcfe, consisting of 34% oil and 66% 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 2008 was approximately 1.9 Bcfe. At year end 2008, our share of estimated proved reserves attributed to the field was 7.8 Bcfe, consisting of 91% oil and 9% natural gas.

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 the Gulf of Mexico operations of Forest Oil Corporation

(Forest) and in January 2008 through our acquisition of an indirect subsidiary of StatoilHydro ASA that owns substantially all of its former Gulf of Mexico shelf assets and operations. We increased our interests in shelf operations to 335 blocks at year-end 2008 from 235 blocks at year-end 2007. 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 existing platform facilities, to high-impact, deep shelf exploration prospects at depths approaching 20,000 total vertical feet.

During 2008, our Gulf of Mexico shelf operation produced approximately 63.1 Bcfe (53% of our total production) and accounted for approximately 338.6 Bcfe or 35% of our total estimated proved reserves at year end. Natural gas accounted for 76% of total shelf production for 2008. We drilled 17 wells in the region during 2008 with an 88% success rate.

Our largest field in the Gulf of Mexico Shelf by reserves is Vermilion 380. At year-end 2008, estimated proved reserves attributed to this field were 33.1 Bcfe, consisting of approximately 50% oil and 50% natural gas. During 2008, we drilled three wells and completed one well before Hurricane Ike damaged the platform. Hurricane Ike also interrupted the drilling of a fourth well. Remaining development involves finishing the drilling of the fourth well, drilling a fifth well and completing the remaining wells. We anticipate that production from the five new wells will commence by third quarter 2009. The field currently has two producing wells (one of which is the new well we drilled and completed in 2008) in 340 feet of water. These two wells produced approximately 0.5 Bcfe in 2008. We generated this prospect from former Forest properties and hold a 100% working interest in the newly drilled wells.

We operate Vermilion 14/26/35, which consists of 10 producing wells in less than 20 feet of water. We hold a 100% working interest in this field. It has been producing for more than 20 years from numerous formations and in 2008 produced approximately 1.5 Bcfe net. At year-end 2008, estimated proved reserves attributed to this field were 30.1 Bcfe, consisting of approximately 8% oil and 92% natural gas.

We operate our 100% working interest in West Cameron 110 which consists of 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 and produced approximately 4.7 Bcfe net in 2008. At year-end 2008, estimated proved reserves attributed to this field were 29.3 Bcfe, consisting of approximately 4% oil and 96% natural gas.

We operate South Pass 24, which consists of 25 producing wells in approximately 10 feet of water. We have a 97% working interest in the property. South Pass 24 has been producing for more than 50 years from numerous formations, and in 2008 produced approximately 1.8 Bcfe net. At year-end 2008, estimated proved reserves attributed to this field were 21.5 Bcfe, consisting of approximately 61% oil and 39% natural gas.

We operate High Island 116, which consists of one producing well in approximately 30 feet of water. We have a 100% working interest in the property. It has been producing for more than 20 years and in 2008 produced approximately 0.8 Bcfe net. At year-end 2008, estimated proved reserves attributed to this field were 19.5 Bcfe, consisting of approximately 3% oil and 97% 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, 2008.

	Volumes	Revenue (In thousands)
Permian Basin:		
Natural Gas (Bcf)	4.0	$ 31,339
Oil (Mbbls)	1,242.8	122,005
NGLs (Mbbls)	578.5	30,765
Total Natural Gas Equivalent (Bcfe)	14.9	$ 184,109
Gulf of Mexico Deepwater:		
Natural Gas (Bcf)	27.7	$ 271,979
Oil (Mbbls)	1,850.5	180,131
NGLs (Mbbls)	264.7	15,053
Total Natural Gas Equivalent (Bcfe)	40.4	$ 467,163
Gulf of Mexico Shelf:		
Natural Gas (Bcf)	48.1	$ 467,099
Oil (Mbbls)	1,787.7	190,504
NGLs (Mbbls)	714.7	39,897
Total Natural Gas Equivalent (Bcfe)	63.0	$ 697,500
Total Production:		
Natural Gas (Bcf)	79.8	$ 770,417
Oil (Mbbls)	4,881.0	492,640
NGLs (Mbbls)	1,557.9	85,715
Total Natural Gas Equivalent (Bcfe)	118.4	$ 1,348,772

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		
	2008	2007	2006
Estimated proved oil and natural gas reserves:			
Natural gas reserves (Bcf)	558.0	448.4	426.7
Oil (MMbbls)	43.8	41.9	32.0
Natural gas liquids (MMbbls)	25.5	22.6	16.1
Total proved oil and natural gas reserves (Bcfe)	973.9	835.8	715.5
Total proved developed reserves (Bcfe)	677.7	563.9	408.7
PV10 value(1) ($ in millions):			
Proved developed reserves	$ 1,530.1	$ 2,389.1	$ 1,198.9
Proved undeveloped reserves	137.4	675.1	362.6
Total PV10 value(1)	$ 1,667.5	$ 3,064.2	$ 1,561.5
Standardized measure of discounted future net cash flows	$ 1,483.0	$ 2,231.9	$ 1,239.8
Prices used in calculating end of period proved reserve measures (excluding effects of hedging):			
Natural gas ($/MMBtu)	$ 5.71	$ 6.79	$ 5.62
Oil ($/bbl)	$ 44.61	$ 96.01	$ 61.06

The following table sets forth certain information with respect to our estimated proved reserves by geographic area as of December 31, 2008 based on estimates made in a reserve report prepared by Ryder Scott Company, L.P.

	Estimated Proved Reserve Quantities							
Geographic Area	Natural Gas (Bcf)	Oil (MMbbls)	NGLs (MMbbls)	Total (Bcfe)	PV10 Value(1) Developed	Undeveloped	Total	Standardized Measure (In millions)
					(In millions of dollars)			
Permian Basin	136.2	27.3	22.7	436.6	359.3	(46.3)	313.0	
Gulf of Mexico Deepwater	165.9	5.4	0.1	198.7	608.5	25.2	633.7	
Gulf of Mexico Shelf	255.9	11.1	2.7	338.6	562.3	158.5	720.8	

Total	558.0	43.8	25.5	973.9	1,530.1	137.4	1,667.5	
Proved Developed Reserves	420.9	25.9	16.9	677.7				$ 1,483.0

(1) PV10 value (PV10) is not a measure under generally accepted accounting principles in the United States of America (GAAP) and 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 affect 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,

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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 16. 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.

Non-GAAP Reconciliation:	Year Ended December 31, 2008	2007 (In millions)	2006
Present value of estimated future net revenues (PV10)	$ 1,667.5	$ 3,064.2	$ 1,561.5
Future income taxes, discounted at 10%	(184.5)	(832.3)	(321.7)
Standardized measure of discounted future net cash flows	$ 1,483.0	$ 2,231.9	$ 1,239.8

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 and operating costs, 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, 2008 and December 31, 2007.

	Year Ended December 31, 2008		2007	
	Gross	Net	Gross	Net
Oil	936.0	733.0	939.0	684.0
Natural Gas	154.0	90.2	223.0	130.0
Total	1,090.0	823.2	1,162.0	814.0

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, 2008.

	Year Ended December 31, 2008			
	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
Permian Basin	72,818	60,801	79,299	48,827
Gulf of Mexico Deepwater	102,560	48,618	393,120	224,275
Gulf of Mexico Shelf	821,250	433,384	455,153	345,204
Other Onshore	1,477	373	5	127
Total	998,105	543,176	927,577	618,433

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The following table sets forth that portion of our onshore and offshore undeveloped acreage as of December 31, 2008 that is subject to expiration absent drilling activity during the three years ended December 31, 2011.

	Undeveloped Acreage Subject to Expiration in the Year Ended December 31,					
	2009		2010		2011	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin	1,520	928	27,439	14,474	35,624	17,665
Gulf of Mexico Deepwater	17,280	14,112	23,040	3,456	40,320	30,960
Gulf of Mexico Shelf	83,526	59,646	37,665	25,364	135,087	103,508
Total	102,326	74,686	88,144	43,294	211,031	152,133

Drilling Activity

Certain information with regard to our drilling activity during the years ended December 31, 2008, 2007 and 2006 is set forth below.

	Year Ended December 31,					
	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Productive	17.00	10.59	11.00	5.96	14.00	5.83
Dry	5.00	2.98	8.00	4.91	8.00	3.65
Total	22.00	13.57	19.00	10.87	22.00	9.48
Development wells:						
Productive	125.00	88.93	121.00	60.43	168.00	86.23
Dry						
Total	125.00	88.93	121.00	60.43	168.00	86.23
Total wells:						
Productive	142.00	99.52	132.00	66.39	182.00	92.06
Dry	5.00	2.98	8.00	4.91	8.00	3.65
Total	147.00	102.5	140.00	71.30	190.00	95.71

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. 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.

	Percentage of Total Revenues for Year Ended December 31,		
Customer	**2008**	**2007**	**2006**
BP Energy	5%	9%	14%
ChevronTexaco and affiliates	16%	23%	23%
Louis Dreyfus Energy	6%	9%	10%
Plains Marketing LP	5%	7%	11%
Shell	10%	10%	8%

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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 performed customary investigation of, and 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.

Royalty Relief

The Outer Continental Shelf Deep Water Royalty Relief Act (RRA), effective November 28, 1995, provides that all tracts in the Western and Central Planning Areas of the Gulf of Mexico, including whole lease blocks in the Eastern Planning Area of the Gulf of Mexico lying west of 87 degrees, 30 minutes West longitude, in water more than 200 meters deep and offered for bid within five years after the effective date of the RRA, will be entitled to royalty relief 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 effective date of the RRA are referred to as post-Act leases. The RRA also allows federal offshore lessees the opportunity to apply for discretionary royalty relief for new production on leases acquired before the RRA was enacted, or pre-Act leases. If the MMS determines that new production under a pre-Act lease would not be economic without royalty relief, then the MMS may relieve a portion of the royalty to make the project economic.

In addition to granting discretionary royalty relief, the MMS has elected to include royalty relief provisions in many leases issued after November 28, 2000, or 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 before May 3, 2009, unless the lessee obtains a one-year extension. These incentives generally apply only to production that occurs during years when the average price of natural gas on the New York Mercantile Exchange does not exceed the price threshold of $10.15 per million Btu, expressed in 2007 dollars. In regulations published in November 2008, the MMS implemented additional royalty relief provisions to reflect statutory changes enacted in the Energy Policy Act of 2005. The regulations provide enhanced incentives for gas production from wells of at least 20,000 feet of true vertical depth in waters of 400 meters or less. These regulations also expand the royalty relief incentives for natural gas produced from leases in waters 200 to 400 meters deep by entitling such leases to the royalty relief incentives available under the existing regulations for leases in less than 200 meters of water, with two exceptions. First, the incentive for production in waters 200 to 400 meters in depth applies to wells for which drilling began on or after May 18, 2007, rather than March 26, 2003, and that begin production before May 3, 2013, rather than May 3, 2009. Second, the applicable price threshold is $4.55 per million Btu, expressed in 2007 dollars, rather than $10.15.

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

Many of our MMS leases that are subject to royalty relief contain language that suspends 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 remaining below the price threshold specified for that year. Since 2000, commodity prices have exceeded some of the predetermined price thresholds, except in 2002, for a number of our projects. For the affected leases, we have been ordered by the MMS to pay royalties for natural gas produced in some of those years. However, we have challenged the MMS s authority to include price thresholds in six of our post-Act leases awarded in 1996 and 1997. 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 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 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. The MMS generally exercises this authority through standards established under its regulations and related policies. We do not anticipate that we will be affected by changes in federal or state law affecting royalty obligations 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 waters. 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.

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. We do not anticipate that the revisions to the SPCC regulations will cause a material impact on our operations or financial condition.

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.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of the Earth s atmosphere. In response to such studies, the U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases. In addition, at least 17 states have declined to wait for Congress to develop and implement climate control legislation and have already taken legal measures to reduce emissions of greenhouse gases. Also, as a result of the U.S. Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA must consider whether it is required to regulate greenhouse gas emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court s holding in *Massachusetts* that greenhouse gases fall under the Federal Clean Air Act s definition of air pollutant may also result in future regulation of greenhouse gas emissions from stationary sources under various Clean Air Act programs, including those that may be used in our operations. It is not possible at this time to predict how legislation that may be enacted to address greenhouse gas emissions would impact our 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 condition, demand for our operations, 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 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, 2008, we had 276 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 our primary layer of physical damage and windstorm insurance coverage. Our coverage is subject to a $10.0 million per-occurrence deductible for our assets and a $250.0 million per-occurrence loss limit. However, if a single event causes losses to all OIL-insured assets in excess of $750.0 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 annually on June 1, and is subject to a general limit of $100.0 million per occurrence and in the case of named windstorms, a combined annual aggregate limit of $100.0 million covering both property damage and business interruption.

In 2008, our operations were adversely affected by Hurricane Ike. The hurricane resulted in shut-in and delayed production as well as facility repairs and replacement expenses. We are evaluating the nature and extent of damage resulting from the hurricane. With respect to Hurricane Ike, our OIL coverage has a $10.0 million per occurrence deductible and a $250.0 million per occurrence limit, subject to an industry-wide loss limit per occurrence of $750.0 million. To the extent that aggregate claims exceed the OIL industry-wide loss limit per occurrence, we expect our insurance recovery would be reduced pro-rata with all other competing claims from Hurricane Ike and the shortfall covered by our commercial excess insurance, subject to policy limits.

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 $5.0 million per occurrence and a $1.0 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 $1.0 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. During 2008, we settled our Katrina and Rita claims with our excess insurance providers for a one-time payment of $48.5 million. 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.* Effective for annual reports on Forms 10-K for years ending on or after December 31, 2009, certain definitions contained in Rule 4-10(a) will be revised to reflect the SEC s adoption of its final rule on the Modernization of Oil and Gas Reporting. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Recent Accounting Pronouncements for more information.

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.

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 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.

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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.

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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 in an existing well bore to 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.

Item 1A. *Risk Factors.*

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

The recent worldwide financial and credit crisis could lead to an extended worldwide economic recession and have a material adverse effect on our results of operations and liquidity.

The recent worldwide financial and credit crisis has reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide. The shortage of liquidity and credit combined with recent substantial losses in worldwide equity markets could lead to an extended worldwide economic recession. A recession or slowdown in economic activity would likely reduce worldwide demand for energy and result in lower oil and natural gas prices, which could materially adversely affect our profitability and results of operations.

In addition, the economic crisis may adversely affect our liquidity. We may be unable to obtain adequate funding under our bank credit facility because our lending counterparties may be unwilling or unable to meet their funding obligations, or because our borrowing base under the facility may be decreased as the result of a redetermination, reducing it due to lower oil or natural gas prices, operating difficulties, declines in reserves or other reasons. If funding is not available as needed, or is available only on unfavorable terms, we may be unable to meet our obligations as they come due or we may be unable to implement our business strategies or otherwise take advantage of business opportunities or respond to competitive pressures.

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 increased to, and then declined significantly from, historical highs in 2008 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. In addition, we may, from time to time, enter into long-term contracts based upon our reasoned expectations for commodity price levels. If commodity prices subsequently decrease significantly for a sustained period, we may be unable to perform our obligations or otherwise breach the contract and be liable for damages.

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, 2008, approximately 30% 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.

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. At December 31, 2008, the net capitalized cost of our proved oil and gas properties exceeded the ceiling limit and we recorded a non-cash ceiling test impairment of $575.6 million during the fourth quarter. Refer to Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates Oil and Gas Properties, and 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 for a discussion of our use of the full cost method of accounting for our oil and gas properties and its impact at December 31, 2008. We may incur other 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 50% 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, 2008, approximately 20% of our total estimated proved reserves were developed non-producing and approximately 30% 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 may 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.

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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 Gulf of Mexico deepwater 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 oil and natural gas prices by approximately $100.8 million in 2008. 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 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 periodically results 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.

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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 fully 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 and in 2008 from Hurricane Ike, 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.

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 one or more of our excess cash flow, debt financings and 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.

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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;
- 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 under the bank credit facility. 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 or a cross default under each 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, 2008, our leases covered approximately 94,226 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 2008 were approximately $2.1 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. Section 304 of the RRA relieves lessees of the obligation to pay royalties on certain leases until after a designated volume has been produced. Four of these leases held by Mariner and two held by MERI that are producing or have produced contain lease language (inserted by the MMS) that conditions royalty relief on commodity prices remaining below specified thresholds. Since 2000, commodity prices have exceeded some of the predetermined thresholds, except in 2002. In May 2006 and September 2008, the MMS issued orders asserting that the price thresholds had been exceeded in calendar years 2000, 2001, and each of the years from 2003 through 2007, and, accordingly, that royalties were due under such leases on oil and gas produced in those years. The potential liability of MERI under its leases relate to production from the leases commencing July 1, 2005, the effective date of Mariner s acquisition of MERI. Mariner and MERI believe that the MMS did not have the statutory authority to include commodity price threshold language in the leases governed by Section 304 of the RRA and accordingly have withheld payment of royalties. Mariner and MERI have challenged the MMS s authority in pending administrative appeals for those leases for which the MMS has issued orders to pay.

The enforceability of the price threshold provisions in leases granted pursuant to Section 304 of the RRA is currently being litigated in several administrative appeals filed by other companies in addition to Mariner, as well as in *Kerr-McGee Oil & Gas Corp. v. Allred*, No. 08-30069 (5th Cir.). In the *Kerr-McGee* litigation, the district court in the Western District of Louisiana granted Kerr-McGee s motion for summary judgment, ruling that the price threshold provisions are unlawful and unenforceable under Section 304 of the RRA. *Kerr-McGee Oil & Gas Corp. v. Allred*, No. 2:06 CV 0439 (W.D. La.) (Mem. Ruling filed Oct. 30, 2007). The Department of the Interior appealed that judgment to the United States Court of Appeals for the Fifth Circuit. On January 12, 2009, the Fifth Circuit affirmed the district court s judgment that the price provisions are unlawful based on Section 304 of the RRA. *Kerr-McGee Oil & Gas Corp. v. U.S. Dep t of Interior*, F.3d , 2009 WL 57883 (5th Cir. Jan. 12, 2009). Until the appeals process is complete, we will continue to monitor the case. Given the judicial history of the case, we determined that as of December 31, 2008, we no longer will record a liability for our estimated exposure to the MMS on our leases granted pursuant to Section 304 of the RRA. At December 31, 2008, this liability would have been $57.3 million, including interest. In addition, as of December 31, 2008, we began including in our estimated proved reserves those reserves attributable to these RRA Section 304 leases which, at December 31, 2008, was approximately 18.1 Bcfe.

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.

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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, 2009) 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	51	Chairman of the Board, Chief Executive Officer and President
Dalton F. Polasek	57	Chief Operating Officer
John H. Karnes	47	Senior Vice President, Chief Financial Officer and Treasurer
Mike C. van den Bold	46	Senior Vice President and Chief Exploration Officer
Judd A. Hansen	53	Senior Vice President Shelf and Onshore
Teresa G. Bushman	59	Senior Vice President, General Counsel and Secretary
Cory L. Loegering	53	Senior Vice President Deepwater
Jesus G. Melendrez	50	Senior Vice President Corporate Development
Richard A. Molohon	54	Vice President Reservoir Engineering
Michael C. McCullough	63	Vice President Acquisitions and Divestitures
Kenneth E. Moore, Jr.	62	Vice President Onshore Land

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 and the Society of Petroleum Engineers.

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

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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 more than 20 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.

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 30 years of experience in conducting operations in the oil and gas industry.

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.

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 31 years of experience in the 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.

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 30 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.

Michael C. McCullough Mr. McCullough was promoted to Vice President Acquisitions and Divestitures in February 2008. He served as Manager, Acquisitions/Exploitation from March 2006 to February 2008, and as Senior Reservoir Engineer from May 2004 to March 2006. Mr. McCullough was employed by Basin Exploration, Inc. from 1999 to 2001 and its successor, Stone Energy Corporation, from 2001 to 2004, in general reservoir engineering, lease sales and acquisitions capacities. He has approximately

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40 years of industry engineering experience, beginning his career in 1968 as a production engineer with Mobil Oil Corporation.

Kenneth E. Moore, Jr. Mr. Moore was promoted to Vice President Onshore Land in February 2008. A Certified Professional Landman, he was employed by Mariner in December 2004 as Onshore Business Development Manager and in November 2006, became Manager, Land/Business Development (Onshore). Mr. Moore served Mariner from November 2003 to December 2004 as an independent contractor performing land services through his firm Moore Land & Minerals which provided a full range of land services to various clients in the Texas Gulf Coast and the Permian Basin areas from September 2001 to December 2004. Mr. Moore has almost 35 years of industry land experience, beginning his career in 1974 as a landman with Gulf Oil Corporation.

PART II

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

Mariner s common stock trades on the New York Stock Exchange (NYSE) under the symbol ME. The following table sets forth the reported high and low closing sales prices of our common stock for the periods indicated:

Year	Period Ended	High	Low
2007	First Quarter	$ 20.33	$ 16.95
	Second Quarter	25.65	19.30
	Third Quarter	25.26	18.87
	Fourth Quarter	25.00	20.67
2008	First Quarter	$ 29.60	$ 23.69
	Second Quarter	37.01	26.84
	Third Quarter	36.45	19.77
	Fourth Quarter	19.54	7.48

As of February 20, 2009 there were 763 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 did not pay any cash dividends for fiscal years 2007 or 2008. 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 3. Long-Term Debt in the Notes to the Consolidated Financial Statements in Part II, Item 8 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	12/31/08
Mariner Energy, Inc.	$ 100.00	$ 96.69	$ 112.88	$ 50.32
S&P 500 Index	$ 100.00	$ 110.18	$ 114.07	$ 70.17
Peer Group(2)	$ 100.00	$ 97.09	$ 103.74	$ 37.16

(1) Total return assuming reinvestment of dividends. Assumes $100 invested on March 3, 2006 in each of Mariner s common stock, the S&P 500 Index, and a peer group of companies. Initial data is taken from March 3, 2006, the date on which Mariner s common stock 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, Callon Petroleum Co., Energy Partners, Ltd., McMoRan Exploration Co., Plains Exploration & Production Company, Stone Energy Corporation, and W&T Offshore, Inc. This peer group differs by one member from the peer group for the stock performance graph included in our 2007 annual report. McMoRan Exploration Co. replaces Bois d Arc Energy, Inc. which ceased to exist in 2008 when it was merged into a wholly-owned subsidiary of peer group member Stone Energy Corporation.

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, 2008 to October 31, 2008(1)	3,235	$ 16.31		
November 1, 2008 to November 30, 2008(1)		$		
December 1, 2008 to December 31, 2008(1)	2,639	$ 8.96		
Total	5,874	$ 13.01		

(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, 2008, 2007, 2006 and 2005, the period from March 3, 2004 through December 31, 2004, and the period from January 1, 2004 through March 2, 2004. The historical consolidated financial data as of and for the years ended December 31, 2008, 2007 and 2006, are derived from Mariner s audited Consolidated Financial Statements included herein, and the historical consolidated financial data as of and for the year ended December 31, 2005, and for the periods March 3, 2004 through December 31, 2004 (Post-2004 Merger) and January 1, 2004 through March 2, 2004 (Pre-2004 Merger), 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,
	2008	2007	2006	2005	2004	2004
	(In thousands, except per share data)					
Statement of Operations Data:						
Total revenues(1)	$ 1,300,507	$ 874,765	$ 659,505	$ 199,710	$ 174,423	$ 39,764
Operating expenses(2)	264,832	174,522	105,739	32,218	23,322	5,191
Depreciation, depletion and amortization	467,265	384,321	292,180	59,469	54,281	10,630
General and administrative expense	60,613	42,151	33,622	36,766	7,641	1,131
Operating (loss) income(3)	(381,712)	268,710	227,470	69,168	88,222	22,812
Interest expense, net of amounts capitalized	56,398	54,665	39,649	8,172	6,045	5
(Benefit) Provision for income taxes	(48,223)	77,324	67,344	21,294	28,783	8,072
Net (loss) income	(388,713)	143,934	121,462	40,481	53,619	14,826

Earnings per common share:												
Net (loss) income per common share basic	$	(4.44)	$	1.68	$	1.59	$	1.24	$	1.80	$	0.50
Net (loss) income per common share diluted	$	(4.44)	$	1.67	$	1.58	$	1.20	$	1.80	$	0.50

(1) Includes effects of hedging.

(2) Operating expenses include lease operating expense, severance and ad valorem taxes and transportation expenses.

(3) 2008 includes \$575.6 million of full cost ceiling test impairment, \$295.6 million of goodwill impairment and \$15.3 million of other property impairment.

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	December 31,				
	2008	2007	2006	2005	2004
	(In thousands)				
Balance Sheet Data:(1)					
Current Assets	$ 374,953	$ 248,980	$ 306,018	$ 141,432	$ 65,746
Current Liabilities	425,564	315,189	239,727	204,006	101,412
Working capital deficit	$ (50,611)	$ (66,209)	$ 66,291	$ (62,574)	$ (35,666)
Property and equipment, net	2,929,877	2,420,194	2,012,062	515,943	303,773
Total assets	3,392,793	3,083,635	2,680,153	665,536	376,019
Long-term debt, less current maturities	1,170,000	779,000	654,000	156,000	115,000
Stockholders equity	1,120,320	1,391,018	1,302,591	213,336	133,907

(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					Pre-2004 Merger
	Year Ended December 31,				Period from March 3, through December 31,	Period from January 1, through March 2,
	2008	2007	2006	2005	2004	2004
	(In thousands)					
Cash Flow Data:						
Net cash provided by operating activities	$ 862,017	$ 536,113	$ 277,161	$ 165,444	$ 135,243	$ 20,295
Net cash used in investing activities	$ (1,264,784)	$ (643,779)	$ (561,390)	$ (247,799)	$ (132,977)	$ (15,341)
Net cash provided (used) by financing activities	$ 387,429	$ 116,676	$ 289,252	$ 84,370	$ (64,853)	$

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 the Permian Basin and the Gulf of Mexico. As of December 31, 2008, approximately 70% of our total estimated proved reserves were classified as proved developed, with approximately 45% of the total estimated proved reserves located in the Permian Basin, 20% in the Gulf of Mexico deepwater and 35% on the Gulf of Mexico shelf.

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 historically have been very volatile. Oil and natural gas prices increased to, and then declined significantly from, historical highs in 2008 and may fluctuate and decline 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.

The recent worldwide financial and credit crisis has reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide. The shortage of liquidity and credit combined with recent substantial losses in worldwide equity markets could lead to an extended worldwide economic recession. A recession or slowdown in economic activity would likely reduce worldwide demand for energy and result in lower oil and natural gas prices, which could materially adversely affect our profitability and results of operations.

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Acquisitions. On December 19, 2008, we acquired additional working interests in our existing property, Atwater Valley Block 426 (Bass Lite), for approximately $32.6 million, increasing our working interest by 11.6% to 53.8%. We internally estimated proved reserves attributable to the acquisition of approximately 17.6 Bcfe (100% natural gas).

On January 31, 2008, we acquired 100% of the equity in a subsidiary of Hydro Gulf of Mexico, Inc. pursuant to a Membership Interest Purchase Agreement executed on December 23, 2007. The acquired subsidiary, now known as Mariner Gulf of Mexico LLC (MGOM), was an indirect subsidiary of StatoilHydro ASA and owns substantially all of its former Gulf of Mexico shelf operations. A summary of these assets and operations as of January 1, 2008 includes:

- Ryder Scott Company, L.P. estimated proved oil and gas reserves of 49.7 Bcfe, 93% of which are developed;
- interests in 36 (16 net) producing wells producing approximately 53 MMcfe per day net to MGOM s interest, 76% of which Mariner now operates;
- 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 $243.0 million for MGOM, subject to customary purchase price adjustments, including $8.0 million for reimbursement of drilling costs attributable to the High Island 166 #5 well.

On December 31, 2007, February 29, 2008, and December 1, 2008 we acquired additional working interests in certain of our existing properties in the Spraberry field in the Permian Basin. We internally estimated proved reserves attributable to the December 2007 acquisition of approximately 94.9 Bcfe (75% oil and NGLs), to the February 2008 acquisition of approximately 14.0 Bcfe (65% oil and NGLs) and to the December 2008 acquisition of approximately 13.4 Bcfe (66% oil and NGLs). We operate substantially all of the assets. The purchase prices, subject to customary purchase price adjustments, were approximately $122.5 million for the December 2007 acquisition, $21.7 million for the February 2008 acquisition and $19.4 million for the December 2008 acquisition.

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.

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Results of Operations

Year Ended December 31, 2008 compared to Year Ended December 31, 2007

Operating and Financial Results for the Year Ended December 31, 2008 Compared to the Year Ended December 31, 2007

	Year Ended December 31, 2008	Year Ended December 31, 2007	Increase (Decrease)	% change
	(In thousands, except average sales price)			
Summary Operating Information:				
Net Production:				
Natural gas (MMcf)	79,756	67,793	11,963	18%
Oil (Mbbls)	4,881	4,214	667	16%
Natural gas liquids (Mbbls)	1,558	1,200	358	30%
Total natural gas equivalent (MMcfe)	118,389	100,273	18,116	18%
Average daily production (MMcfe per day)	323	275	48	18%
Hedging Activities:				
Natural gas revenue gain (loss)	$ (28,047)	$ 58,465	$ (86,512)	(148)%
Oil revenue loss	(72,762)	(13,388)	(59,374)	443%
Total hedging revenue gain (loss)	$ (100,809)	$ 45,077	$ (145,886)	(324)%
Average Sales Prices:				
Natural gas (per Mcf) realized(1)	$ 9.31	$ 7.88	$ 1.43	18%
Natural gas (per Mcf) unhedged	9.66	7.02	2.64	38%
Oil (per Bbl) realized(1)	86.02	67.50	18.52	27%
Oil (per Bbl) unhedged	100.93	70.68	30.25	43%
Natural gas liquids (per Bbl) realized(1)	55.02	45.16	9.86	22%
Natural gas liquids (per Bbl) unhedged	55.02	45.16	9.86	22%
Total natural gas equivalent ($/Mcfe) realized(1)	10.54	8.71	1.83	21%
Total natural gas equivalent ($/Mcfe) unhedged	11.39	8.26	3.13	38%
Summary of Financial Information:				
Natural gas revenue	$ 742,370	$ 534,537	$ 207,833	39%
Oil revenue	419,878	284,405	135,473	48%
Natural gas liquids revenue	85,715	54,192	31,523	58%
Other revenues	52,544	1,631	50,913	3,122%
Lease operating expense	231,645	152,627	79,018	52%
Severance and ad valorem taxes	18,191	13,101	5,090	39%
Transportation expense	14,996	8,794	6,202	71%
General and administrative expense	60,613	42,151	18,462	44%
Depreciation, depletion and amortization	467,265	384,321	82,944	22%
Full cost ceiling test impairment	575,607		575,607	N/A
Goodwill impairment	295,598		295,598	N/A
Other property impairment	15,252		15,252	N/A
Net interest expense	56,398	53,262	3,136	6%

Income (Loss) before taxes and minority interest	(436,748)	221,259	(658,007)	(297)%
(Benefit) Provision for income taxes	(48,223)	77,324	(125,547)	(162)%
Net income (loss)	(388,713)	143,934	(532,647)	(370)%
Average Unit Costs per Mcfe:				
Lease operating expense	$ 1.96	$ 1.52	$ 0.44	29%
Severance and ad valorem taxes	0.15	0.13	0.02	15%
Transportation expense	0.13	0.09	0.04	44%
General and administrative expense	0.51	0.42	0.09	21%
Depreciation, depletion and amortization	3.95	3.83	0.12	3%

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

Net loss for 2008 was $388.7 million compared to net income of $143.9 million for 2007. The decrease was primarily attributable to $886.5 million in impairments resulting from our full cost ceiling test, other property impairment and goodwill, as discussed below. Basic and fully-diluted earnings per share for 2008 were $(4.44) for each measure compared to $1.68 and $1.67, respectively for 2007.

Net production Natural gas production increased approximately 18% in 2008 to approximately 218 MMcf per day, compared to approximately 186 MMcf per day in 2007. Oil production increased 16% in 2008 to approximately 13,300 barrels per day, compared to approximately 11,500 barrels per day in 2007. Natural gas liquids production increased 30% in 2008 and total overall production increased 18% in 2008 to approximately 323 MMcfe per day, compared to 275 MMcfe per day in 2007. Natural gas production comprised approximately 67% of total production in both 2008 and 2007.

Net production in the Gulf of Mexico for 2008 increased 16% to 103.5 Bcfe from 89.1 Bcfe for 2007 primarily reflecting the start up in 2008 of production from several new projects, most notably, Northwest Nansen located in East Breaks 602 (which contributed 12.9 Bcfe) and Bass Lite located in Atwater 426 (which contributed 8.4 Bcfe), and the impact of our acquisition of MGOM (which contributed 13.1 Bcfe). This increase was offset by the impacts of Hurricanes Gustav and Ike in the third quarter which resulted in net shut-in production (assuming pre-hurricane net production levels remained constant) of approximately 20 Bcfe.

Onshore production for 2008 increased 33% to 14.9 Bcfe from 11.2 Bcfe for 2007, primarily as a result of our acquisition of additional interests and drilling and development of existing acreage in the Permian Basin (which contributed 2.6 Bcfe in 2008).

Natural gas, oil and NGL revenues for 2008 increased 43% to $1,248.0 million compared to $873.1 million for 2007 as a result of increased pricing (approximately $217.1 million, net of the effect of hedging), and increased production (approximately $157.8 million).

During 2008, our revenues reflected a net recognized hedging loss of $100.8 million comprised of $98.8 million in unfavorable cash settlements and an unrealized loss of $2.0 million related to the ineffective portion not eligible for deferral under SFAS 133. This compares to a net recognized hedging gain of approximately $45.1 million for 2007, comprised of $46.7 million in favorable cash settlements and an unrealized loss of $1.6 million related to the ineffective portion not eligible for deferral under SFAS 133.

Our natural gas and oil average sales prices, and the effects of hedging activities on those prices, were as follows:

	Realized	Unhedged	Hedging (Loss) Gain	% Change
Year Ended December 31, 2008:				
Natural gas (per Mcf)	$ 9.31	$ 9.66	$ (0.35)	(4)%
Oil (per Bbl)	86.02	100.93	(14.91)	(15)%
Year Ended December 31, 2007:				
Natural gas (per Mcf)	$ 7.88	$ 7.02	$ 0.86	12%
Oil (per Bbl)	67.50	70.68	(3.18)	(4)%

Other revenues for 2008 increased approximately $50.9 million to $52.5 million from $1.6 million for 2007 as a result of the release of suspended revenue of $46.5 million related to a potential MMS royalty liability and $4.3 million of imputed rent from the lease of office property acquired in January 2008.

Lease operating expense (LOE) in 2008 increased approximately $79.0 million to $231.6 million from $152.6 million for 2007, primarily as a result of a $36.0 million multiple-year retrospective contingent OIL insurance premium. LOE also was imparted by start-up of production in February 2008 from Bass Lite and Northwest Nansen, the acquisition of MGOM in January 2008, and the impact of the additional Permian Basin assets acquired at year-end 2007, which are long-lived and typically carry a higher per-unit LOE.

Severance and ad valorem tax for 2008 increased approximately $5.1 million to $18.2 million from $13.1 million for 2007 due to increased severance as a result of higher oil prices and increased production from the drilling and completion of additional wells and our acquisition of additional interests in the Permian Basin.

Transportation expense for 2008 increased approximately $6.2 million to $15.0 million from $8.8 million for 2007 due primarily to commencement of production in 2008 at Bass Lite, Northwest Nansen, Galveston 352 and High Island A467.

General and administrative expense (G&A) for 2008 increased approximately $18.4 million to $60.6 million from $42.2 million for 2007. The increase was due primarily to an increase in stock compensation expense of approximately $10.1 million to $21.0 million from $10.9 million for 2007. This increase was primarily due to long-term performance-based restricted stock awarded during 2008. See Note 5. Share-Based Compensation in the Notes to the Consolidated Financial Statements in Part II, Item 8 of this Annual Report on Form 10-K for more detail on stock grants. Beginning in 2008, that portion of Lafayette and Midland office expense that is directly related to production activity was classified as LOE, and we began capitalizing stock compensation expense attributable to those non-officer employees directly engaged in exploration, development and acquisition activities. Capitalized G&A related to our acquisition, exploration and development activities increased $5.8 million to $19.8 million in 2008 from $14.0 million in 2007.

Depreciation, depletion, and amortization expense for 2008 increased approximately $83.0 million to $467.3 million from $384.3 million for 2007, primarily as a result of increased production from our acquisitions of MGOM and additional interests in the Permian Basin properties, and start-up production from Bass Lite and Northwest Nansen.

Full cost ceiling test impairment of $575.6 million was recognized in December 2008 as a result of the net capitalized cost of our proved oil and gas properties exceeding our ceiling limit. See Critical Accounting Policies and Estimates Oil and Gas Properties for more detail on this impairment.

Goodwill impairment of $295.6 million was recorded in the fourth quarter of 2008 as a result of our annual impairment test. The goodwill was originally recorded in conjunction with the Forest Merger and the impairment is a result of weakened economic conditions and a decline in our stock price during the fourth quarter of 2008. See Critical Accounting Policies and Estimates Goodwill for more detail on this impairment.

Other property impairment of $15.3 million was recognized as a result of our annual impairment assessement performed on our other property. See Critical Accounting Policies and Estimates Other Property for more detail on this impairment.

Net interest expense for 2008 increased approximately $3.1 million to $56.4 million from $53.3 million for 2007 due primarily to an increase in average daily debt levels, partially offset by lower interest rates, and an additional four months of interest expense related to our 8% Senior Notes due 2017 issued on April 30, 2007. Capitalized interest increased to $9.7 million in 2008 from $0.5 million in 2007.

Income before taxes and minority interest for 2008 decreased approximately $658.0 million to a loss of $436.7 million from income of $221.3 million for 2007 due primarily to $886.5 million in impairments related to our full cost ceiling test, other property and goodwill as discussed above.

Provision for income taxes for 2008 reflected an effective tax rate of 11.0% as compared to 34.9% for 2007. The decrease in our effective tax rate was due primarily to a permanent book-tax difference attributable to the goodwill impairment discussed above. Excluding this permanent book-tax difference, the effective rate for 2008 would have been 34.2%.

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	$ 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	62.61	8.07	13%
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%
Other revenues	1,631	3,287	(1,656)	(50)%
Lease operating expense	152,627	91,592	61,035	67%
Severance and ad valorem taxes	13,101	9,070	4,031	44%
Transportation expense	8,794	5,077	3,717	73%
General and administrative expense	42,151	33,622	8,529	25%
Depreciation, depletion and amortization	384,321	292,180	92,141	32%
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%
Average Unit Costs per Mcfe:				
Lease operating expense	$ 1.52	$ 1.14	$ 0.38	33%

Severance and ad valorem taxes	0.13	0.11	0.02	18%
Transportation expense	0.09	0.06	0.03	50%
General and administrative expense	0.42	0.42		
Depreciation, depletion and amortization	3.83	3.63	0.20	6%

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

Net income for 2007 was $143.9 million compared to $121.5 million for 2006. The increase was primarily the result of higher operating income attributable to 12 full months of our ownership of the Forest Gulf of Mexico operations. Basic and fully-diluted earnings per share for 2007 were $1.68 and $1.67, respectively compared to $1.59 and $1.58, respectively for 2006.

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 for 2007 increased 33% to $873.1 million compared to $656.2 million for 2006 as a result of increased pricing (approximately $161.1 million, net of the effect of hedging), and increased production (approximately $55.9 million).

During 2007, our revenues reflect a net recognized hedging gain of approximately $45.1 million, comprised of $46.7 million in favorable cash settlements and an unrealized loss of $1.6 million related to the ineffective portion not eligible for deferral under SFAS 133. This compares to a net recognized hedging gain of approximately $33.0 million for 2006, comprised of $11.3 million in favorable cash settlements and an unrealized gain of $4.2 million related to the ineffective portion not eligible for deferral under SFAS 133. 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.

The effects of hedging activities on our average sales prices were as follows:

	Realized	Unhedged	Hedging Gain (Loss)	% Change
Year Ended December 31, 2007:				
Natural gas (per Mcf)	$ 7.88	$ 7.02	$ 0.86	12%
Oil (per Bbl)	67.50	70.68	(3.18)	(4)%
Year Ended December 31, 2006:				
Natural gas (per Mcf)	$ 7.37	$ 6.78	$ 0.59	9%
Oil (per Bbl)	62.63	59.68	2.95	5%

Lease operating expense in 2007 increased 67% to $152.6 million from $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 to $17.8 million in 2007 from $10.5 million in 2006 as a result of Hurricanes Katrina and Rita. Field costs increased $7.6 million year-over-year in the Permian Basin with the addition of new productive wells in the Spraberry field.

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 the Permian Basin properties.

Transportation expense for 2007 was $8.8 million compared to $5.1 million for 2006. The increase 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 6% 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.

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General and administrative expense totaled $42.2 million for 2007, compared to $33.6 million for 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, 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.

Liquidity and Capital Resources

Financial Condition

	Years Ended December 31,	
	2008	**2007**
	(In thousands, except ratios)	
Current ratio(1)	0.9 to 1	0.8 to 1
Working capital deficit(2)	(50,611)	(66,209)
Total debt	1,170,000	779,000
Operating cash flow(3)	885,887	622,610
Interest expense, net of capitalization	56,398	54,665
Fixed-charge coverage ratio(4)	(5.63)	4.93

Total cash and marketable securities less debt	(1,166,749)	(760,411)
Stockholders equity	1,120,320	1,391,018
Total liabilities to equity	2.03 to 1	1.22 to 1

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

(2) Working capital deficit 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, share-based compensation expense, impairments and minority interest. 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.)

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,	
	2008	**2007**
	(In thousands)	
Cash flow from operating activities (GAAP)	$ 862,017	$ 536,113
Changes in operating assets and liabilities	23,870	86,497
Operating cash flow (Non-GAAP)	$ 885,887	$ 622,610

2008 Cash Flows

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

	Years Ended December 31,		
	2008	**2007**	**2006**
		(In millions)	
Cash payments for interest	$ 62.2	$ 49.1	$ 28.8
Cash payments for income taxes	2.9	$ 0.6	$

Net cash provided by operating activities increased by $325.9 million to $862.0 million in 2008 from $536.1 million in 2007. The increase was due to greater operating revenue due to an increase in production of 48 MMcfe per day or $157.8 million and an increase in the realized price per Mcfe of $1.83 or $217.1 million, offset by higher lease operating expense.

As of December 31, 2008, the Company had a working capital deficit of $50.6 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 $1,264.8 million in 2008 from $643.8 million in 2007 primarily due to the acquisition of MGOM (including approximately $15.0 million of mid-stream assets reflected in other property), increased capital expenditures attributable to increased activity in our drilling programs, and an increase in other property reflecting an investment of approximately $34.6 million in office property. This increase was partially offset by $31.8 million of restricted cash released in January 2007 from the sale of our interest in Garden Banks 422 (Cottonwood).

Net cash flows provided by financing activities were $387.4 million for 2008 compared to $116.7 million for 2007. The increase was due primarily to $223.5 million borrowed in January 2008 under our bank credit facility to finance the purchase of MGOM and net increased borrowings of $342.5 million for working capital requirements. This increase was partially offset by the decrease attributable to the proceeds received from our issuance in April 2007 of $300.0 million aggregate principal amount of 8% senior notes due in 2017.

2008 Uses of Capital. Our primary uses of capital during 2008 were as follows:

- funding capital expenditures (excluding hurricane repairs and acquisitions) of approximately $1,005.7 million;
- funding hurricane repairs and hurricane-related abandonment expenditures of approximately $55.6 million;
- paying interest of approximately $62.2 million;

funding the purchase of MGOM for approximately $223.5 million; and

paying routine operating and administrative expenses.

2008 Capital Expenditures. The following table presents major components of our capital expenditures during 2008 compared to 2007.

	Year Ended December 31, 2008	2007
	(In thousands)	
Capital expenditures:		
Oil and natural gas development	$ 588,456	$ 448,577
Oil and natural gas property acquisitions	302,629	122,895
Oil and natural gas exploration	270,767	182,645
Leasehold acquisitions	152,567	24,189
Corporate expenditures and other	66,668	15,952
Proceeds from property conveyances(1)		(4,116)
Total capital expenditures, net of proceeds from property conveyances	$ 1,381,087	$ 790,142

(1) Proceeds from sale of Cottonwood project in 2006 (Garden Banks 244) were recorded as restricted cash of which $5.0 million remained as of December 31, 2007 (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).

2008 Hurricane Expenditures. During the year ended 2008, we incurred approximately $21.7 million in hurricane expenditures resulting from Hurricanes Ike and Gustav, of which $0.8 million were repairs and $20.9 were capital expenditures. Since 2004, we have incurred approximately $213.5 million in hurricane expenditures from Hurricanes Ike, Gustav, Ivan, Katrina and Rita, of which $0.8 million were repairs, $158.2 were capital expenditures and $54.5 million were hurricane-related abandonment costs. Net of our deductible of $14.4 million and insurance proceeds received of $69.4 million, our insurance receivable at December 31, 2008 was $35.3 million, of which an estimated $13.1 million is expected to be settled within the next 12 months. However, due to the magnitude of Hurricanes Ike, 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 assured. We expect to maintain a potentially significant insurance receivable through 2010 in respect of Hurricane Ike while we actively pursue settlement of our claims to minimize the impact to our working capital and liquidity. We expect to recover substantially all of our outstanding OIL claims in respect of Hurricanes Katrina and Rita by 2010. Any differences between our insurance recoveries and insurance receivables will be recorded as adjustments to our oil and natural gas properties.

2008 Sources of Capital. Our primary sources of capital during 2008 were as follows:

cash flow from operations;

borrowings under our revolving bank credit facility; and insurance proceeds.

Bank Credit Facility We have a secured revolving credit facility with a group of banks pursuant to an amended and restated credit agreement dated March 2, 2006, as further amended. The credit facility matures January 31, 2012 and is subject to a borrowing base which is redetermined periodically. As of December 31, 2008, maximum credit availability under the facility was $1.0 billion, including up $50.0 million in letters of credit, subject to a borrowing base of $850.0 million scheduled to be redetermined in February 2009. The redetermination was pending on February 28, 2009, and we anticipate that it will occur in March 2009.

The lenders redetermine the borrowing base periodically based upon their evaluation of our oil and gas reserves and other factors. Any increase in the borrowing base requires the consent of all lenders. The outstanding principal balance of loans under the 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, we 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.

Borrowings under the bank credit facility bear interest at either a LIBOR-based rate or a prime-based rate, at our option, plus a specified margin. We must pay a commitment fee of 0.250% to 0.375% per year on unused availability under the bank credit facility. We have used borrowings under the facility to facilitate the Forest Merger and acquisition of MGOM, and have used and may use borrowings under the facility for general corporate purposes.

As of December 31, 2008 and 2007, $570.0 million and $179.0 million, respectively, were outstanding under the credit facility, and the interest rates were 3.31% and 7.25%, respectively. In addition, as of December 31, 2008 five letters of credit totaling $7.2 million were outstanding, of which $4.2 million was required for plugging and abandonment obligations at certain of our offshore fields.

Payment and performance of our obligations under the credit facility (including any obligations under commodity and interest rate hedges entered into with facility lenders) are secured by liens upon substantially all of our assets, and guaranteed by our subsidiaries, other than MERI which is a co-borrower. We also are subject to various restrictive covenants and other usual and customary terms and conditions, including limits on additional debt, cash dividends and other restricted payments, liens, investments, asset dispositions, mergers and speculative hedging. Financial covenants under the credit facility require us 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.

We were in compliance with the financial covenants under the bank credit facility as of December 31, 2008. Our breach of these covenants would be an event of default, after which the lenders could terminate their lending obligations and accelerate maturity of any outstanding indebtedness under the credit facility which then would become due and payable in full. An unrescinded acceleration of maturity under the bank credit facility would constitute an event of default under our senior notes described below, which could trigger acceleration of maturity of the indebtedness evidenced by the senior notes.

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 (the 71/2% Notes)

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

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.

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.

2009 Capital Expenditures. In the second half of 2008, a world-wide economic recession and oversupply of natural gas in North America led to an unprecedented decline in oil and gas prices. However, the inflated cost of oil field services resulting from sustained historically high commodity prices did not decrease

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in line with the decline in commodity prices. The prospect of continued low commodity prices and disproportionately high service costs has constrained the industry s capital reinvestment and undermined rates of return in new projects, particularly those in areas characterized by high costs or long reserve lives. In order to manage our capital program within expected cash flows, we tentatively have reduced our 2009 capital budget by more than 50% from 2008. Refer to Item. 1. Business Impact of Worldwide Financial Crisis and Lower Commodity Prices on Capital Program in Part I of this Annual Report on Form 10-K for an outline of our planned 2009 activities in the Permian Basin and Gulf of Mexico.

We anticipate that our base operating capital expenditures for 2009 will be approximately $430.6 million (excluding hurricane-related expenditures and acquisitions), with significant potential for increase or decrease depending upon drilling success and cash flow experience during the year. Approximately 48% of the base operating capital program is planned to be allocated to development activities, 45% to exploration activities, and the remainder to other items (primarily capitalized overhead and interest). In addition, we estimate to incur additional hurricane-related costs of $36.1 million during 2009 related to Hurricane Ike, that we believe is substantially covered under applicable insurance. 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, 2008:

		Payments Due By Period			
	Total	2009	2010-2011	2012-2013	Thereafter
			(In thousands)		
Debt obligations(1)	$ 1,170,000	$	$	$ 870,000	$ 300,000
Interest obligations(2)	355,523	65,367	130,734	78,545	80,877
Operating leases	21,646	2,240	5,031	4,498	9,877
Abandonment liabilities	408,244	82,364	73,393	83,205	169,282
Seismic obligations	3,000	2,333	667		
Capital accrual obligations	195,833	195,833			
OIL Theoretical Withdrawal(3)	36,000	6,391	14,586	15,023	
Rig commitment	183,882	124,450	59,432		
Other liabilities(4)	99,091	99,091			
Total contractual cash commitments	$ 2,473,219	$ 578,069	$ 283,843	$ 1,051,271	$ 560,036

(1) As of December 31, 2008, we incurred debt obligations under our bank credit facility, the Notes.

(2) Interest obligations represent interest due on the bank credit facility and the 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 3.31% weighted average interest rate on amounts outstanding under our bank credit facility as of December 31, 2008, our cash payments for interest would be $18.9 million annually for 2009 through 2011 and $1.6 million in 2012.

(3)

We accrued approximately $36.0 million as of December 31, 2008, for an insurance premium contingency related to our membership in OIL. As part of our membership, we are obligated to pay a withdrawal premium if we elect to withdraw from OIL. We do not anticipate withdrawing from OIL; however, due to the contingency, OIL calculates a potential withdrawal premium annually based on past losses and we accrue a liability for the potential premium. OIL requires smaller members to provide a letter of credit or other acceptable security in favor of OIL to secure payment of the withdrawal premium. Acceptable security has included a letter of credit or a security agreement pursuant to which a member grants OIL a security interest in certain claim proceeds payable by OIL to the member. We anticipate that we will enter into such a security agreement, granting to OIL a security interest in a portion of our Hurricane Ike claim proceeds payable by OIL. We expect to have the ability to replace the security agreement with a letter of credit or other acceptable security in favor of OIL.

(4) Other liabilities include accrued LOE of $30.9 million, accrued liabilities of $11.0 million, gas balancing of $15.9 million, oil and gas payable of $24.5 million, accrued compensation of $10.7 million, other G&A of $4.2 million and other liabilities for $1.9 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 2009, 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-funding 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.

In addition, the recent worldwide financial and credit crisis may adversely affect our liquidity. We may be unable to obtain adequate funding under our bank credit facility because our lending counterparties may be unwilling or unable to meet their funding obligations, or because our borrowing base under the facility may be decreased as the result of a redetermination, reducing it due to lower oil or natural gas prices, operating difficulties, declines in reserves or other reasons. If funding is not available as needed, or is available only on unfavorable terms, we may be unable to meet our obligations as they come due or we may be unable to implement our business strategies or otherwise take advantage of business opportunities or respond to competitive pressures.

Off-Balance Sheet Arrangements

Mariner s bank credit facility has a letter of credit subfacility of up to $50.0 million that is included as a use of the borrowing base. As of December 31, 2008, five such letters of credit totaling $7.2 million were outstanding.

Fair Value Measurement

We determine fair value for our natural gas and crude oil costless collars using fair value measurements based on the Black-Scholes valuation model, adjusted for credit risk. The credit risk adjustment for collar liabilities is based on our credit quality and the credit risk adjustment for collar assets is based on the credit quality of our counterparty. Such valuations have historically approximated our exit price for such derivatives. We validate the fair value measurements of our collars using a Black-Scholes pricing model using observable market data, to the extent available, and unobservable or adjusted data, if observable data is not available or is not representative of fair value. As of December 31, 2008, our internal calculations of fair value were determined using market data.

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We determine the fair value of our natural gas and crude oil fixed price swaps by reference to forward pricing curves for natural gas and oil futures contracts. The difference between the forward price curve and the contractual fixed price is discounted to the measurement date using a credit-risk adjusted discount rate. The credit risk adjustment for swap liabilities is based on our credit quality and the credit risk adjustment for swap assets is based on the credit quality of our counterparty. Our fair value determinations of our swaps have historically approximated our exit price for such derivatives.

Due to unavailability of observable volatility data input or use of adjusted implied volatility for our collars, we have determined that fair value measurements of all of our collars are categorized as level 3 in accordance with SFAS No. 157, Fair Value Measurements (SFAS 157) (see Note 9, Fair Value Measurements in the Notes to Consolidated Financial Statements in Part II, Item 8 of this Annual Report on Form 10-K). As of December 31, 2008 we had no collars outstanding. We have determined that the fair value methodology described above for our swaps is consistent with observable market inputs and have categorized our swaps as level 2 in accordance with SFAS 157.

During the twelve months ended December 31, 2008, we recorded an asset for the increase in the fair value of our derivative financial instruments of $154.2 million, principally due to the decrease in natural gas and oil commodity prices below our swap prices and floor prices in our collars. The increase was comprised of an increase in accumulated other comprehensive income of approximately $165.7 million, net of income taxes of $91.3 million, approximately $98.8 million of unfavorable cash hedging settlements during the period reflected in natural gas and oil revenues, and an unrealized non-cash loss due to hedging ineffectiveness under SFAS 133 of approximately $2.0 million reflected in natural gas revenues.

We expect the continued volatility of natural gas and oil commodity prices to have a material impact on the fair value of our derivatives positions. It is our intent to hold all of our derivatives positions to maturity such that realized gains or losses are generally recognized in income when the hedged natural gas or oil is produced and sold. While the derivatives settlements may decrease (or increase) our effective price realized, the ultimate settlement of our derivatives positions is not expected to materially adversely affect our liquidity, results of operations or cash flows.

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 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.

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 G&A costs. G&A costs associated with production, operations, marketing and general corporate activities are expensed as incurred. The capitalized costs, coupled with our estimated asset retirement obligations recorded in accordance with Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations (SFAS 143), are included in the amortization base and amortized to expense using the unit-of-production method. Amortization is calculated based on estimated proved oil and gas reserves. Proceeds from the sale or disposition of oil and gas properties are applied to reduce net capitalized costs unless the sale or disposition causes a significant change in the relationship between costs and the estimated value of proved reserves.

Capitalized costs (net of accumulated depreciation, depletion and amortization and deferred income taxes) of proved oil and gas properties are subject to a ceiling. The ceiling limits these costs to an amount equal to the present value, discounted at 10%, of estimated future net cash flows from estimated proved reserves less estimated future operating and development costs, abandonment costs (net of salvage value) and estimated related future income taxes. 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 differentials. Price is held constant over the life of the reserves.

We use derivative financial instruments that qualify for cash flow hedge accounting under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, (SFAS 133) to hedge against the volatility of natural gas prices. 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 exceed the ceiling limit, the excess is impaired and recorded in the Consolidated Statements of Operations.

At December 31, 2008, the net capitalized cost of proved oil and gas properties exceeded the ceiling limit due to a decline in oil and gas commodity prices during the fourth quarter 2008 and the Company recorded a non-cash ceiling test impairment of $575.6 million during the fourth quarter. The writedown would have been $695.6 million if we had not used hedge adjusted prices for the volumes that were subject to hedges. The ceiling limit of our proved reserves was calculated based upon quoted market prices of $5.71 per Mcfe for gas and $44.61 per barrel for oil, adjusted for market differentials for the year ended December 31, 2008. If commodity prices continue to deteriorate during the first quarter of 2009, we may be required to record a ceiling test impairment which could be material to our financial position and results of operations.

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 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. Interest is capitalized on the costs in unproved properties while in the development stage. 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.

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Abandonment Liability

In accordance with SFAS 143, we record the fair value of a liability for the legal obligation to retire an asset in the period in which it is incurred and capitalize the corresponding cost by increasing the carrying amount of the related long-lived asset. Upon our adoption of SFAS 143, we recorded an asset retirement obligation to reflect our legal obligations related to future plugging and abandonment of its oil and natural gas wells. 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, the difference is recognized in Oil and Gas Properties.

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.

Other Property

Other property and equipment is recorded at cost and consists of real estate, IT equipment, office furniture and fixtures, leasehold improvements and gas gathering systems. Acquisitions and betterments are capitalized; maintenance and repairs are expensed as incurred. 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. Per SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (SFAS 144), we assess other property for impairment when events indicate the carrying value exceeds fair value. As a result of our SFAS 144 assessment performed at December 31, 2008, an impairment of $15.3 million was recorded related to office property.

Goodwill

We account for goodwill in accordance with SFAS No. 142 Goodwill and Other Intangible Assets (SFAS 142). SFAS 142 requires goodwill to be tested for impairment on an annual basis and between annual tests when events or circumstances indicate a potential impairment. In a purchase transaction, 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. We follow the full cost method of accounting and all of our oil and gas properties are located in the United States. For the purpose of performing an impairment test, we have determined that we have one reporting unit. Our goodwill impairment reviews consist of a two-step process. The first step is to determine the fair value of our reporting unit and compare it to the carrying value of the related net assets. Fair value is determined based on our estimates of market values. If this fair value exceeds the carrying value no further analysis or goodwill write-down is required. The second step is required if the fair value of the reporting unit is less than the carrying value of the net assets. In this step the implied fair value of the reporting unit is allocated to all the underlying assets and liabilities, including both recognized and unrecognized tangible and intangible assets, based on their fair values. If necessary, goodwill is then written-down to its implied fair value.

We perform our goodwill test annually on November 30 and more often if circumstances require. Amounts recorded in goodwill relate to the excess purchase price paid in association with the Forest Merger. See Note 2. Acquisitions and Dispositions Forest Gulf of Mexico Operation in the Notes to the Consolidated Financial Statements in Part II, Item 8 of this Annual Report on Form 10-K.

In connection with our annual impairment test on November 30, 2008, we performed a step one impairment analysis. As a result of weakened economic conditions and a decline in our stock price during the fourth quarter of 2008, the carrying value of our reporting unit exceeded the fair value and a step two analysis was required to determine the impairment. Our fair value estimates in step two were developed using a weighted average cost of capital (WACC) of 12.0% and a control premium of 25.0%. A 1.0% increase and decrease of the WACC would have changed the fair value by (3.7%) and 4.0% respectively. We allocated the estimated fair value determined using these assumptions to the identifiable tangible and intangible assets and liabilities of our reporting unit based on their respective values. This allocation indicated no residual value for goodwill and we recorded approximately $295.6 million of goodwill impairment in continuing operations as of December 31, 2008. We had previously determined that there was no impairment loss in continuing operations

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as of December 31, 2007 and 2006, respectively. In 2007, goodwill decreased as a result of changes in the book and tax basis related to the Forest Merger.

Income Taxes

Our provision for taxes includes both state and federal taxes. The Company records its federal income taxes in accordance with SFAS No. 109, Accounting for Income Taxes (SFAS 109) 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 basis 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.

Effective January 1, 2007, we adopted FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes (an interpretation of FASB Statement No. 109) (FIN 48). This interpretation clarified the accounting for uncertainty in income taxes recognized in the financial statements by prescribing a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. 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. We do not have uncertain tax positions outstanding and, as such, did not recorded a FIN 48 liability for the years ended December 31, 2008 and 2007.

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.

Derivative Financial Instruments

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 cash flow hedges in accordance with SFAS 133. 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. The Company presents the fair value of its derivatives on a net basis in accordance with FASB Interpretation No. 39 Offsetting of Amounts Related to Certain Contracts an interpretation of APB Opinion No. 10 and FASB Statement No. 105 (FIN 39).

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. Mark-to-market 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.

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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 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.

Revenue Recognition

Oil revenues are recognized when production is sold to a purchaser at a fixed or determinable price, and delivery has occurred and title has transferred. Natural gas and 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 recorded 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 use the Black-Scholes option pricing model to determine the fair value of options on the grant date, which requires judgment in estimating the expected life of the option and the expected volatility of our stock. We use a Monte Carlo simulation to estimate the fair value of restricted stock granted in 2008 under our stock incentive plan s long-term performance-based restricted stock program.

Recent Accounting Pronouncements

On December 31, 2008, the SEC issued the final rule, *Modernization of Oil and Gas Reporting* (Final Rule). The Final Rule adopts revisions to the SEC s oil and gas reporting disclosure requirements and is effective for annual reports on Forms 10-K for years ending on or after December 31, 2009. Early adoption of the Final Rule is prohibited. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves to help investors evaluate their investments in oil and gas companies. The amendments are also designed to modernize the oil and gas disclosure requirements to align

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them with current practices and changes in technology. Revised requirements in the SEC s Final Rule include, but are not limited to:

Oil and gas reserves must be reported using the average price over the prior 12 month period, rather than year-end prices;

Companies will be allowed to report, on an optional basis, probable and possible reserves;

Non-traditional reserves, such as oil and gas extracted from coal and shales, will be included in the definition of oil and gas producing activities ;

Companies will be permitted to use new technologies to determine proved reserves, as long as those technologies have been demonstrated empirically to lead to reliable conclusions with respect to reserve volumes;

Companies will be required to disclose, in narrative form, additional details on their proved undeveloped reserves (PUDs), including the total quantity of PUDs at year end, any material changes to PUDs that occurred during the year, investments and progress made to convert PUDs to developed oil and gas reserves and an explanation of the reasons why material concentrations of PUDs in individual fields or countries have remained undeveloped for five years or more after disclosure as PUDs;

Companies will be required to report the qualifications and measures taken to assure the independence and objectivity of any business entity or employee primarily responsible for preparing or auditing the reserves estimates.

We are currently evaluating the potential impact of the Final Rule. The SEC is discussing the Final Rule with the FASB staff to align FASB accounting standards with the new SEC rules. These discussions may delay the required compliance date. Absent any change in the effective date, we will begin complying with the disclosure requirements in our annual report on Form 10-K for the year ended December 31, 2009.

In October 2008, the FASB issued Staff Position (FSP) No. 157-3, Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active (FSP 157-3). FSP 157-3 applies to financial assets within the scope of accounting pronouncements that require or permit fair value measurements in accordance with SFAS No. 157, Fair Value Measurements (SFAS 157) and clarifies the application of SFAS 157 in a market that is not active. This FSP also provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. This FSP was effective upon issuance, including prior periods for which financial statements have not been issued. Revisions resulting from a change in the valuation technique or its application are accounted for as a change in accounting estimate according to SFAS No. 154 Accounting Changes and Error Corrections . The adoption of FSP 157-3 did not have a material effect on the Company s results of operations, financial position or cash flows.

In May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles (SFAS 162). SFAS 162 is intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements that are presented in conformity with GAAP for nongovernmental entities. The FASB believes that the GAAP hierarchy should be directed to entities because it is the entity (not its auditor) that is responsible for selecting accounting principles for financial statements that are presented in conformity with GAAP. This statement became effective on November 15, 2008 following the SEC s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles. The adoption of SFAS 162 did not have a material effect on our results of operations, financial position or cash flows.

In April 2008, the FASB issued FSP No. 142-3, Determination of the Useful Life of Intangible Assets (FSP 142-3). FSP 142-3 amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under FASB Statement No. 142, Goodwill and Other Intangible Assets. FSP 142-3 is effective for financial statements issued after December 15, 2008. The adoption of FSP 142-3 did not have a material effect on our results of operations, financial position, or cash flows.

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In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133 (SFAS 161). SFAS 161 is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures to enable investors to better understand their effects on an entity s financial position, financial performance, and cash flows. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. SFAS 161 also improves transparency about the location and amounts of derivative instruments in an entity s financial statements; how derivative instruments and related hedged items are accounted for under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS 133); and how derivative instruments and related hedged items affect its financial position, financial performance, and cash flows. SFAS 161 achieves these improvements by requiring disclosure of the fair values of derivative instruments and their gains and losses in a tabular format. It also provides more information about an entity s liquidity by requiring disclosure of derivative features that are credit-risk related. Finally, it requires cross-referencing within footnotes to enable financial statement users to locate important information about derivative instruments. We currently are evaluating the effect the adoption of SFAS 161 will have on our results of operations, financial position and cash flows.

In December 2007, the 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 with the effect dependent upon acquisitions at that time.

In December 2007, the 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 adoption of SFAS 160 is not expected to have a material effect on our results of operations, financial position or cash flows.

During February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (SFAS 159). 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 was effective for the Company as of January 1, 2008. SFAS 159 did not have an impact on the Company s Consolidated Financial Statements as the Company elected not to measure at fair value additional financial assets and liabilities not already required to be measured at fair value.

In September 2006, the FASB issued 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 was effective for fiscal years beginning after November 15, 2007. In February 2008, the FASB issued FSP No. FAS 157-2, Effective Date of FASB Statement No. 157, which delayed the effective date of SFAS 157 for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). This FSP is effective for financial statements issued during fiscal years beginning after November 15, 2008, and interim periods within those fiscal years for items within the scope of this FSP. Accordingly, our adoption of

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SFAS 157 was limited to financial assets and liabilities, which primarily affects the valuation of the Company s derivative contracts. The adoption of SFAS 157 with respect to financial assets and liabilities did not have a material impact on our net asset values (see Note 11 to the Consolidated Financial Statements in Part II, Item 8 of this Annual Report on Form 10-K). The Company is still in the process of evaluating SFAS 157 with respect to its effect on nonfinancial assets and liabilities and therefore has not yet determined the impact that it will have on its financial statements upon full adoption in 2009. Nonfinancial assets and liabilities for which the Company has not applied the provisions of SFAS 157 include its asset retirement obligations and assets held for future sale when applicable.

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 2008 levels, a 10% increase in commodity prices from those as of December 31, 2008 would increase our cash flow by approximately $134.9 million for the year ended December 31, 2009.

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.

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,		
	2008	2007	2006
	(In thousands)		
Cash (Loss) Gain on Settlements	$ (98,814)	$ 46,732	$ 11,273
(Loss) Gain on Hedge Ineffectiveness(1)	(1,995)	(1,655)	4,175
Non-cash Gain on hedges acquired(2)			17,523
Total	$ (100,809)	$ 45,077	$ 32,971

(1) Unrealized (loss) gain 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.

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As of December 31, 2008, the Company had the following hedging activity outstanding:

Fixed Price Swaps	Quantity	Weighted-Average Fixed Price (In thousands)	Fair Value Asset
Natural Gas (MMbtus)			
January 1 December 31, 2009	31,642,084	$ 8.48	$ 74,709
Crude Oil (Bbls)			
January 1 December 31, 2009	2,172,210	$ 76.15	47,220
Total			$ 121,929

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

Fixed Price Swaps	Quantity	Weighted-Average Fixed Price (In thousands)	Fair Value Asset/(Liability)
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	Fair Value Asset/(Liability)
		(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 February 20, 2009, there were no hedging transactions entered into subsequent to December 31, 2008 except as follows:

Period	Instrument Type	Quantity	Weighted Average Price	
Natural Gas (MMbtus) 2009				
January 1 December 31	Fixed Price Swaps	19,665,000	$	6.19 Fixed
Crude Oil (Bbls) 2009				
February 1 December 31	Fixed Price Swaps	977,047	$	51.46 Fixed

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.

As of December 31, 2008, the Company expects to realize within the next 12 months approximately $121.9 million in net gains resulting from hedging activities that are currently recorded in accumulated other comprehensive income. These hedging gains are expected to be realized as an increase of $47.2 million to oil revenues and an increase of $74.7 million to natural gas revenues. On January 29, 2008, the Company liquidated crude oil fixed price swaps in respect of 977 thousand barrels in exchange for a cash payment of $10.1 million and installment payments of $13.5 million to be received monthly throughout 2009.

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Interest Rates

Borrowings under our bank credit facility 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 2008, the interest rate on our outstanding bank debt was 3.31%. If the balance of our bank debt at December 31, 2008 were to remain constant, a 10% increase in market interest rates would decrease our cash flow by approximately $1.9 million for the year ended December 31, 2008.

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, 2008. Deloitte & Touche LLP, Mariner s independent auditor for 2008, 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
March 2, 2009

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, 2008 and 2007, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2008. We also have audited the Company s internal control over financial reporting as of December 31, 2008, 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, 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, 2008, 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
March 2, 2009

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MARINER ENERGY, INC.

CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007
	(In thousands, except share data)	
Current Assets:		
Cash and cash equivalents	$ 3,251	$ 18,589
Receivables, net of allowances of $3,868 and $2,449, respectively	219,920	157,774
Insurance receivables	13,123	26,683
Derivative financial instruments	121,929	11,863
Intangible assets	2,353	17,209
Prepaid expenses and other	14,377	10,630
Deferred tax asset		6,232
Total current assets	374,953	248,980
Property and Equipment:		
Proved oil and gas properties, full-cost method	4,448,146	3,118,273
Unproved properties, not subject to amortization	201,121	40,455
Total oil and gas properties	4,649,267	3,158,728
Other property and equipment	53,115	15,545
Accumulated depreciation, depletion and amortization:		
Proved oil and gas properties	(1,767,028)	(751,127)
Other properties	(5,477)	(2,952)
Total accumulated depreciation, depletion and amortization	(1,772,505)	(754,079)
Total property and equipment, net	2,929,877	2,420,194
Restricted Cash		5,000
Goodwill		295,598
Insurance Receivables	22,132	56,924
Derivative Financial Instruments		691
Other Assets, net of amortization	65,831	56,248
TOTAL ASSETS	$ 3,392,793	$ 3,083,635
Current Liabilities:		
Accounts payable	$ 3,837	$ 1,064
Accrued liabilities	107,815	96,936
Accrued capital costs	195,833	159,010
Deferred income tax	23,148	
Abandonment liability	82,364	30,985
Accrued interest	12,567	7,726
Derivative financial instruments		19,468
Total current liabilities	425,564	315,189

Long-Term Liabilities:		
Abandonment liability	325,880	191,021
Deferred income tax	319,766	343,948
Derivative financial instruments		25,343
Long-term debt	1,170,000	779,000
Other long-term liabilities	31,263	38,115
Total long-term liabilities	1,846,909	1,377,427
Commitments and Contingencies (see Note 8)		
Minority Interest		1
Stockholders Equity:		
Preferred stock, $.0001 par value; 20,000,000 shares authorized, no shares issued and outstanding at December 31, 2008 and December 31, 2007		
Common stock, $.0001 par value; 180,000,000 shares authorized, 88,846,073 shares issued and outstanding at December 31, 2008; 180,000,000 shares authorized, 87,229,312 shares issued and outstanding at December 31, 2007	9	9
Additional paid-in-capital	1,071,347	1,054,089
Accumulated other comprehensive income/(loss)	78,181	(22,576)
Accumulated retained earnings	(29,217)	359,496
Total stockholders equity	1,120,320	1,391,018
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 3,392,793	$ 3,083,635

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,		
	2008	2007	2006
	(In thousands except share data)		
Revenues:			
Natural gas	$ 742,370	$ 534,537	$ 412,967
Oil	419,878	284,405	202,744
Natural gas liquids	85,715	54,192	40,507
Other revenues	52,544	1,631	3,287
Total revenues	1,300,507	874,765	659,505
Costs and Expenses:			
Lease operating expense	231,645	152,627	91,592
Severance and ad valorem taxes	18,191	13,101	9,070
Transportation expense	14,996	8,794	5,077
General and administrative expense	60,613	42,151	33,622
Depreciation, depletion and amortization	467,265	384,321	292,180
Full cost ceiling test impairment	575,607		
Goodwill impairment	295,598		
Other property impairment	15,252		
Other miscellaneous expense	3,052	5,061	494
Total costs and expenses	1,682,219	606,055	432,035
OPERATING (LOSS) INCOME	(381,712)	268,710	227,470
Other Income/(Expenses):			
Interest income	1,362	1,403	985
Interest expense, net of amounts capitalized	(56,398)	(54,665)	(39,649)
Other income		5,811	
(Loss) Income Before Taxes and Minority Interest	(436,748)	221,259	188,806
Benefit (Provision) for Income Taxes	48,223	(77,324)	(67,344)
Minority Interest	(188)	(1)	
NET (LOSS) INCOME	$ (388,713)	$ 143,934	$ 121,462
Earnings per share:			
Net (loss) income per share basic	$ (4.44)	$ 1.68	$ 1.59
Net (loss) income per share diluted	$ (4.44)	$ 1.67	$ 1.58
Weighted average shares outstanding basic	87,491,385	85,645,199	76,352,666
Weighted average shares outstanding diluted	87,491,385	86,125,811	76,810,466

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, 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)		(14,027)			(14,027)
Forfeiture of restricted stock	(27)					
Amortization of unearned compensation			9,247			9,247
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 loss				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
Common shares issued restricted stock	1,734					
Treasury stock bought and cancelled on same day	(144)		(4,313)			(4,313)
Forfeiture of restricted stock	(29)					
Amortization of unearned compensation			20,327			20,327
Share-based compensation expense stock options			502			502
Stock options exercised	56		742			742
Comprehensive income (loss):						
Net loss					(388,713)	(388,713)
Change in fair value of derivative hedging instruments net of income taxes of ($35,891)				(64,918)		(64,918)
Hedge settlements reclassified to income net of income taxes of $91,316				165,675		165,675
Total comprehensive income (loss)				100,757	(388,713)	(287,956)
Balance at December 31, 2008	88,846	$ 9	$ 1,071,347	$ 78,181	$ (29,217)	$ 1,120,320

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, 2008	2007	2006
	(In thousands)		
Cash flow from operating activities:			
Net (loss) income	$ (388,713)	$ 143,934	$ 121,462
Adjustments to reconcile net income to net cash provided by operating activities:			
Deferred income tax	(49,403)	77,324	67,344
Depreciation, depletion and amortization	467,265	384,321	295,292
Ineffectiveness of derivative instruments	1,995	1,655	(4,175)
Full cost ceiling test impairment	575,607		
Goodwill impairment	295,598		
Other property impairment	15,252		
Share-based compensation	21,017	10,890	10,229
MMS royalty relief and other	(52,731)	4,486	226
Changes in operating assets and liabilities:			
Receivables	(63,015)	(9,805)	(12,972)
Insurance receivables	47,839	(22,606)	(55,690)
Prepaid expenses and other	(1,853)	(23,406)	18,626
Accounts payable and accrued liabilities	(6,841)	(30,680)	(169,819)
Net realized loss on derivative contracts acquired			6,638
Net cash provided by operating activities	862,017	536,113	277,161
Cash flow from investing activities:			
Acquisitions and additions to oil and gas properties	(1,220,067)	(674,740)	(540,374)
Additions to other property and equipment	(49,717)		(2,207)
Property conveyances		4,130	33,829
Purchase price adjustment			(20,808)
Restricted cash designated for investment	5,000	26,830	(31,830)
Minority interest		1	
Net cash used in investing activities	(1,264,784)	(643,779)	(561,390)
Cash flow from financing activities:			
Debt and working capital acquired from Forest Energy Resources, Inc.			(176,200)
Repayment of term note			(4,000)
Credit facility borrowings	1,268,000	564,000	682,000
Credit facility repayments	(877,000)	(739,000)	(480,000)
Proceeds from note offering		300,000	300,000
Repurchase of stock	(4,313)	(1,553)	(14,027)
Net realized loss on derivative contracts acquired			(6,638)

Proceeds from exercise of stock options	742	829	718
Deferred offering costs		(6,600)	(12,601)
Partner contributions/(distributions)		(1,000)	
Net cash provided by financing activities	387,429	116,676	289,252
(Decrease) Increase in Cash and Cash Equivalents	(15,338)	9,010	5,023
Cash and Cash Equivalents at Beginning of Period	18,589	9,579	4,556
Cash and Cash Equivalents at End of Period	$ 3,251	$ 18,589	$ 9,579

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

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
For the Years Ended December 31, 2008, 2007 and 2006

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 the Permian Basin 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 Ma Energy, Inc. and its subsidiaries collectively.

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

Reclassifications and Use of Estimates in the Preparation of Financial Statements Certain prior period amounts have been reclassified to conform to current year presentation. Amounts for litigation expense were presented as Other miscellaneous expense in the Company s Consolidated Statements of Operations for the years ended December 31, 2007 and 2006. These amounts are presented herein as General and administrative expense for comparability to 2008 presentation. Stock compensation expense attributable to those non-officer employees directly engaged in exploration, development and acquisition activities is capitalized. Other reclassifications are insignificant in nature. These reclassifications had no effect on total operating income or 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.

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 at December 31, 2006, see Note 2. 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, 2008 is repair and capital-related costs incurred to bring productive properties back to operating condition after sustaining significant damage from Hurricanes Katrina and Rita in 2005 and Hurricane Ike in 2008. Mariner believes its insurance receivable is collectable under the Company s insurance policies. Any differences between its insurance recoveries and insurance receivables will be recorded as an adjustment to oil and gas properties.

Oil and Gas Properties The Company s 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 eligible general and administrative costs (G&A). G&A costs associated with production, operations, marketing and general corporate activities are expensed as incurred. These capitalized costs, coupled with its estimated asset retirement obligations recorded in accordance with Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2008, 2007 and 2006

Retirement Obligations (SFAS 143), are included in the amortization base and amortized to expense using the unit-of-production method. Amortization is calculated based on estimated proved oil and gas reserves. Proceeds from the sale or disposition of oil and gas properties are applied to reduce net capitalized costs unless the sale or disposition causes a significant change in the relationship between costs and the estimated value of proved reserves.

Capitalized costs (net of accumulated depreciation, depletion and amortization and deferred income taxes) of proved oil and gas properties are subject to a full-cost ceiling limitation. The ceiling limits these costs to an amount equal to the present value, discounted at 10%, of estimated future net cash flows from estimated proved reserves less estimated future operating and development costs, abandonment costs (net of salvage value) and estimated related future income taxes. 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 differentials. Price is held constant over the life of the reserves. The Company uses derivative financial instruments that qualify for cash flow hedge accounting under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, (SFAS 133) to hedge against the volatility of natural gas prices. In accordance with Securities and Exchange Commission (SEC) guidelines, Mariner includes estimated future cash flows from its hedging program in the ceiling test calculation. If net capitalized costs related to proved properties exceed the ceiling limit, the excess is impaired and recorded in the Consolidated Statements of Operations.

At December 31, 2008, the net capitalized cost of proved oil and gas properties exceeded the ceiling limit and the Company recorded a non-cash ceiling test impairment of $575.6 million during the fourth quarter. The writedown would have been $695.6 million if we had not used hedge adjusted prices for the volumes that were subject to hedges. The ceiling limit of its proved reserves was calculated based upon quoted market prices of $5.71 per Mcfe for gas and $44.61 per barrel for oil, adjusted for market differentials for the year ended December 31, 2008. At December 31, 2007 and 2006, respectively, the ceiling limit exceeded the net capitalized costs of our proved oil and gas properties and no impairment was recorded.

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. Interest is capitalized on the costs in unproved properties while in the development stage. 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 the Company owns 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. Mariner makes this determination based on an analysis of leasehold and seismic maps and discussions with its 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. Each property included in our unevaluated property balance is assessed on a quarterly basis for possible impairment or reduction in value.

Abandonment Liability In accordance with SFAS 143, the Company records the fair value of a liability for the legal obligation to retire an asset in the period in which it is incurred with the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. Upon adoption of SFAS 143, the Company recorded an asset retirement obligation to reflect the Company s legal obligations related to future plugging and abandonment of its oil and natural gas wells. The liability is accreted to its then present value

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2008, 2007 and 2006

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, the difference is recognized in Oil and Gas Properties.

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.

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

	2008	2007
	(In thousands)	
Abandonment Liability at beginning of period: January 1	$ 222,006	$ 217,970
Liabilities incurred	46,514	6,662
Liabilities settled	(73,164)	(57,825)
Accretion expense	23,511	16,976
Revisions to previous estimates	144,957	38,223
Liabilities from assets acquired	44,420	
Abandonment Liability at end of period: December 31(1)	$ 408,244	$ 222,006

(1) Includes $82.4 million and $31.0 million classified as a current accrued liability at December 31, 2008 and 2007.

Estimated Proved Reserves The Company s most significant financial estimates are based on estimates of proved oil and natural gas reserves. Estimates of proved reserves are key components in determining the 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 the Company s 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.

Other Property and Equipment Other property and equipment is recorded at cost and consists of real estate, IT equipment, office furniture and fixtures, leasehold improvements and gas gathering systems. Acquisitions and betterments are capitalized; maintenance and repairs are expensed as incurred. 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. Per SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (SFAS 144), the Company assesses other property for impairment when events indicate the carrying value exceeds fair value. As a result of the

Company s SFAS 144 assessment performed at December 31, 2008, an impairment of $15.3 million was recorded related to real estate property.

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MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2008, 2007 and 2006

Other Assets Other assets at December 31, 2008 and 2007 were primarily comprised of the following:

	2008	2007
	(In thousands)	
Oil and gas lease and well equipment held in inventory	$ 41,051	$ 18,918
Earnest money for MGOM acquisition		17,625
Amortizable note offering costs and discounts	11,405	13,912
Prepaid compression	6,435	
Long term deposits	3,767	4,896
Amortizable bank fees	2,034	621
Prepaid seismic	667	
Guarantor payments	472	
Deferred acquisition costs		276
Other Assets, net of amortization(1)	$ 65,831	$ 56,248

(1) Net of accumulated amortization as of December 31, 2008 and 2007 of $6.4 million and $3.6 million, respectively.

Derivative Financial Instruments 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 cash flow hedges in accordance with SFAS 133. 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. The Company presents the fair value of its derivatives on a net basis in accordance with Financial Accounting Standards Board (FASB) Interpretation No. 39 Offsetting of Amounts Related to Certain Contracts an interpretation of APB Opinion No. 10 and FASB Statement No. 105 (FIN 39).

Mariner is 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. Mark-to-market 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 its 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 is designated as a hedge at the time the derivative contract is entered into; and (iii) at the inception of the

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2008, 2007 and 2006

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.

Goodwill The Company accounts for goodwill in accordance with SFAS No. 142 Goodwill and Other Intangible Assets (SFAS 142). SFAS 142 requires goodwill to be tested for impairment on an annual basis and between annual tests when events or circumstances indicate a potential impairment. In a purchase transaction, 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. Amounts recorded in goodwill relate to the excess purchase price paid in association with the acquisition of Forest Energy Resources, Inc. See Note 2. Acquisitions and Dispositions Forest Gulf of Mexico Operations . Mariner follows the full cost method of accounting and all of its oil and gas properties are located in the United States. For the purpose of performing an impairment test, the Company has determined that it has one reporting unit. The goodwill impairment reviews consist of a two-step process. The first step is to determine the fair value of the Company s assets and compare it to the carrying value of the related net assets. Fair value is determined based on estimates of market values. If this fair value exceeds the carrying value no further analysis or goodwill write-down is required. Step two is required if the fair value of the reporting unit is less than the carrying value of the net assets. In this step the implied fair value of the reporting unit is allocated to all the underlying assets and liabilities, including both recognized and unrecognized tangible and intangible assets, based on their fair values. If necessary, goodwill is then written-down to its implied fair value.

The Company performs its goodwill test annually on November 30 and more often if circumstances require. In connection with its annual impairment test on November 30, 2008, Mariner performed a step one impairment analysis. As a result of weakened economic conditions and a decline in its stock price during the fourth quarter of 2008, the carrying value of the Company exceeded the fair value of its net assets and a step two analysis was required to determine the impairment. Mariner s fair value estimates in step two were developed using a weighted average cost of capital (WACC) of 12.0% and a control premium of 25.0%. A 1.0% increase and decrease of the WACC would have changed the fair value by (3.7%) and 4.0% respectively. The Company allocated the estimated fair value determined using these assumptions to the identifiable tangible and intangible assets and liabilities of the Company based on their respective values. This allocation indicated no residual value for goodwill and the Company recorded approximately $295.6 million of goodwill impairment in continuing operations as of December 31, 2008. Mariner had previously determined that there was no impairment loss in continuing operations as of December 31, 2007 and 2006, respectively. In 2007, goodwill decreased as a result of changes in the book and tax basis related to the Forest Merger.

Income Taxes Mariner s provision for taxes includes both state and federal taxes. The Company records its federal income taxes in accordance with SFAS No. 109, Accounting for Income Taxes (SFAS 109) 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 basis 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.

Effective January 1, 2007, the Company adopted FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes (an interpretation of FASB Statement No. 109) (FIN 48). This interpretation clarified the accounting for uncertainty in income taxes recognized in the financial statements by prescribing a

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For the Years Ended December 31, 2008, 2007 and 2006

recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. The Company applies significant judgment in evaluating its tax positions and estimating its 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 1.0% to be imposed on revenues less certain costs, as specified in the legislation.

Revenue Recognition Oil revenues are recognized when production is sold to a purchaser at a fixed or determinable price, and delivery has occurred and title has transferred. Natural gas 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 recorded 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.

Operating Costs The Company classifies its 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 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 which are based on revenue.

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

General and Administrative Expense 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.

Capitalized G&A 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,

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MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2008, 2007 and 2006

exploration and development activities of approximately $19.8 million, $14.0 million and $11.0 million for the years ended December 31, 2008, 2007 and 2006, respectively. Share-based compensation expense is classified with general and administrative expenses, except for amounts attributable to non-officer employees directly engaged in exploration, development and acquisition activities. See Note 5. Stockholders Equity for further discussion on share-based compensation expense.

Overhead Recovery The Company receives reimbursement for administrative and overhead expenses incurred on behalf of other working interest owners on properties it operates. These reimbursements totaling $13.5 million, $12.5 million and $16.7 million for the years ended December 31, 2008, 2007 and 2006, respectively, were allocated as reductions to general and administrative expenses incurred. Generally, Mariner does not receive any reimbursements or fees in excess of the costs incurred; however, if it did, we would credit the excess to the full-cost pool to be recognized through lower cost amortization as production occurs.

Concentration of Credit Risk Mariner extends 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 the industry and may accordingly impact the Company s overall credit risk. However, the Company believes that the risk of these unsecured receivables is mitigated by the size, reputation, and nature of the companies to which it extends credit.

Use of Estimates The preparation of financial statements in conformity with generally accepted accounting principles 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 amounts of revenues and expenses during the reporting period. Significant estimates made by management include (1) oil and natural gas reserves; (2) depreciation, depletion and amortization, including future abandonment costs; (3) assigning fair value and allocating purchase price in connection with business combinations, including goodwill; (4) income taxes; (5) accrued assets and liabilities; (6) stock based compensation; (7) asset retirement obligations and (8) valuation of derivative instruments. Although management believes these estimates are reasonable, actual results could differ from these estimates.

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.

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, 2008, 2007 and 2006:

	Years Ended December 31,		
	2008	2007	2006

	(In thousands)		
Net (Loss) Income	$ (388,713)	$ 143,934	$ 121,462
Other comprehensive (loss) income, net of tax:			
Derivative contracts settled and reclassified, net of tax	(64,918)	29,262	21,431
Change in unrealized mark-to-market gains (losses) arising during period, net of tax	165,675	(94,935)	63,139
Change in accumulated other comprehensive income (loss)	100,757	(65,673)	84,570
Comprehensive (loss) income	$ (287,956)	$ 78,261	$ 206,032

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2008, 2007 and 2006

Major Customers The table below presents the Company s major customers. 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.

Customer	Percentage of Total Revenues for Year Ended December 31, 2008	2007	2006
BP Energy	5%	9%	14%
ChevronTexaco and affiliates	16%	23%	23%
Louis Dreyfus Energy	6%	9%	10%
Plains Marketing LP	5%	7%	11%
Shell	10%	10%	8%

Recent Accounting Pronouncements

On December 31, 2008, the SEC issued the Final Rule, which adopts revisions to the SEC s oil and gas reporting disclosure requirements and is effective for annual reports on Forms 10-K for years ending on or after December 31, 2009. Early adoption of the Final Rule is prohibited. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves to help investors evaluate their investments in oil and gas companies. The amendments are also designed to modernize the oil and gas disclosure requirements to align them with current practices and changes in technology. Revised requirements in the SEC s Final Rule include, but are not limited to:

Oil and gas reserves must be reported using the average price over the prior 12 month period, rather than year-end prices;

Companies will be allowed to report, on an optional basis, probable and possible reserves;

Non-traditional reserves, such as oil and gas extracted from coal and shales, will be included in the definition of oil and gas producing activities ;

Companies will be permitted to use new technologies to determine proved reserves, as long as those technologies have been demonstrated empirically to lead to reliable conclusions with respect to reserve volumes;

Companies will be required to disclose, in narrative form, additional details on their proved undeveloped reserves (PUDs), including the total quantity of PUDs at year end, any material changes to PUDs that occurred during the year, investments and progress made to convert PUDs to developed oil and gas reserves and an explanation of the reasons why material concentrations of PUDs in individual fields or countries have remained undeveloped for five years or more after disclosure as PUDs;

Companies will be required to report the qualifications and measures taken to assure the independence and objectivity of any business entity or employee primarily responsible for preparing or auditing the reserves estimates.

The Company is currently evaluating the potential impact of adopting the Final Rule. The SEC is discussing the Final Rule with the FASB staff to align FASB accounting standards with the new SEC rules These discussions may delay the required compliance date. Absent any change in the effective date, Mariner will begin complying with the disclosure requirements in its annual report on Form 10-K for the year ended December 31, 2009.

In October 2008, the FASB issued Staff Position (FSP) No. 157-3, Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active (FSP 157-3). FSP 157-3 applies to financial assets within the scope of accounting pronouncements that require or permit fair value measurements in

MARINER ENERGY, INC.

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accordance with SFAS No. 157, Fair Value Measurements (SFAS 157) and clarifies the application of SFAS 157 in a market that is not active. This FSP also provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. This FSP was effective upon issuance, including prior periods for which financial statements have not been issued. Revisions resulting from a change in the valuation technique or its application are accounted for as a change in accounting estimate according to SFAS No. 154 Accounting Changes and Error Corrections . The adoption of FSP 157-3 did not have a material effect on the Company s results of operations, financial position or cash flows.

In May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles (SFAS 162). SFAS 162 is intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements that are presented in conformity with GAAP for nongovernmental entities. The FASB believes that the GAAP hierarchy should be directed to entities because it is the entity (not its auditor) that is responsible for selecting accounting principles for financial statements that are presented in conformity with GAAP. This statement became effective on November 15, 2008 following the SEC s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles. The adoption of SFAS 162 did not have a material effect on the Company s results of operations, financial position or cash flows.

In April 2008, the FASB issued FSP No. 142-3, Determination of the Useful Life of Intangible Assets (FSP 142-3). FSP 142-3 amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under FASB Statement No. 142, Goodwill and Other Intangible Assets. FSP 142-3 is effective for financial statements issued after December 15, 2008. The adoption of FSP 142-3 did not have a material effect on the Company s results of operations, financial position or cash flows.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133 (SFAS 161). SFAS 161 is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures to enable investors to better understand their effects on an entity s financial position, financial performance, and cash flows. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. SFAS 161 also improves transparency about the location and amounts of derivative instruments in an entity s financial statements; how derivative instruments and related hedged items are accounted for under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS 133); and how derivative instruments and related hedged items affect its financial position, financial performance, and cash flows. SFAS 161 achieves these improvements by requiring disclosure of the fair values of derivative instruments and their gains and losses in a tabular format. It also provides more information about an entity s liquidity by requiring disclosure of derivative features that are credit-risk related. Finally, it requires cross-referencing within footnotes to enable financial statement users to locate important information about derivative instruments. The Company is currently evaluating the effect the application of SFAS 161 will have on its Consolidated Financial Statements.

In December 2007, the 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 with the effect dependent upon acquisitions at that time.

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In December 2007, the 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 adoption of SFAS 160 is not expected to have a material effect on the Company s results of operations, financial position or cash flows.

During February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (SFAS 159). 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 was effective for the Company as of January 1, 2008. SFAS 159 did not have an impact on the Company s Consolidated Financial Statements as the Company elected not to measure at fair value additional financial assets and liabilities not already required to be measured at fair value.

In September 2006, the FASB issued 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 was effective for fiscal years beginning after November 15, 2007. In February 2008, the FASB issued FSP No. FAS 157-2, Effective Date of FASB Statement No. 157, which delayed the effective date of SFAS 157 for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). This FSP is effective for financial statements issued during fiscal years beginning after November 15, 2008, and interim periods within those fiscal years for items within the scope of this FSP. Accordingly, our adoption of SFAS 157 was limited to financial assets and liabilities, which primarily affects the valuation of the Company s derivative contracts. The adoption of SFAS 157 with respect to financial assets and liabilities did not have a material impact on our net asset values (see Note 11). The Company is still in the process of evaluating SFAS 157 with respect to its effect on nonfinancial assets and liabilities and therefore has not yet determined the impact that it will have on its financial statements upon full adoption in 2009. Nonfinancial assets and liabilities for which the Company has not applied the provisions of SFAS 157 include its asset retirement obligations and assets held for future sale when applicable.

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Note 2. Acquisitions and Dispositions

Gulf of Mexico Shelf Acquisition. On January 31, 2008, Mariner acquired 100% of the equity in a subsidiary of Hydro Gulf of Mexico, Inc. pursuant to a Membership Interest Purchase Agreement executed on December 23, 2007. The acquired subsidiary, now known as Mariner Gulf of Mexico LLC (MGOM), was an indirect subsidiary of StatoilHydro ASA and owns substantially all of its former Gulf of Mexico shelf operations. Mariner paid approximately $243.0 million, subject to customary purchase price adjustments, including $8.0 million for reimbursement of drilling costs attributable to the High Island 166 #5 well.

Pro Forma Financial Information The pro forma information set forth below gives effect to the acquisition of MGOM as if it had been consummated as of the beginning of the applicable period. 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 MGOM. The pro forma information is for illustrative purposes only. The financial results may have been different had MGOM 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 acquisition occurred in the past or the future financial results that the Company will achieve after the acquisition.

	For the Year Ended December 31, 2008	2007
	(Unaudited) (In thousands, except per share amounts)	
Pro Forma:		
Revenue	$ 1,315,200	$ 1,091,372
Net (loss) income available to common stockholders	$ (383,914)	$ 182,628
Basic (loss) earnings per share	$ (4.39)	$ 2.13
Diluted (loss) earnings per share	$ (4.39)	$ 2.12

Permian Basin Acquisitions On December 31, 2007, February 29, 2008 and December 1, 2008, Mariner acquired additional working interests in certain of its existing properties in the Spraberry field in the Permian Basin. Mariner operates substantially all of the assets. The purchase prices, subject to customary purchase price adjustments, were $122.5 million for the December 2007 acquisition $21.7 million for the February 2008 acquisition and $19.4 million for the December 2008 acquisition.

Bass Lite On December 19, 2008, we acquired additional working interests in our existing property, Atwater Valley Block 426 (Bass Lite), for approximately $32.6 million, increasing our working interest by 11.6% to 53.8%. We internally estimated proved reserves attributable to the acquisition of approximately 17.6 Bcfe (100% natural gas).

Interest in Cottonwood On December 1, 2006, Mariner completed the sale of its 20% interest in Garden Banks 244 (Cottonwood) to Petrobras America, Inc., for $31.8 million. The sale was effective November 1, 2006. Proceeds from the sale were deposited in trust with a qualified intermediary to preserve Mariner s ability to reinvest them in a tax-deferred, like-kind exchange transaction for federal income tax purposes. Inasmuch as Mariner elected not to identify replacement like-kind property to facilitate the exchange, proceeds and related interest totaling $32.0 million were disbursed to Mariner on January 19, 2007 and used to repay borrowings under its 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 111 in the Gulf of Mexico. BP retained rights to depths below 15,000 feet.

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The acquisition cost was $70.9 million. 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 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

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preliminary cash payment to Forest of $20.8 million recorded as an offset to current liabilities. Carryover basis accounting applies for tax purposes. During the fourth quarter of 2008, the Company performed its annual impairment analysis and recorded an impairment charge of $295.6 million related to goodwill, see Note 1. Summary of Significant Accounting Policies Goodwill.

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 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 (Unaudited) (In thousands, except per share amounts)	
Pro Forma:		
Revenue	$	725,321
Net income available to common stockholders	$	134,428
Basic earnings per share	$	1.76
Diluted earnings per share	$	1.75

Note 3. Long-Term Debt

As of December 31, 2008 and December 31, 2007 our long-term debt was as follows:

	December 31, 2008 (In thousands)		December 31, 2007	
Bank credit facility	$	570,000	$	179,000
8% Senior Notes		300,000		300,000

71/2% Senior Notes	300,000	300,000
Total long-term debt	$ 1,170,000	$ 779,000

Bank Credit Facility The Company has a secured revolving credit facility with a group of banks pursuant to an amended and restated credit agreement dated March 2, 2006, as further amended. The credit facility matures January 31, 2012 and is subject to a borrowing base which is redetermined periodically. As of December 31, 2008, maximum credit availability under the facility was $1.0 billion, including up $50.0 million in letters of credit, subject to a borrowing base of $850.0 million scheduled to be redetermined in February 2009. The redetermination was pending on February 28, 2009, and Mariner anticipates that it will occur in March 2009.

The lenders redetermine the borrowing base periodically based upon their evaluation of the Company s oil and gas reserves and other factors. Any increase in the borrowing base requires the consent of all lenders. The outstanding principal balance of loans under the credit facility may not exceed the borrowing base. If the

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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.

Borrowings under the bank credit facility bear interest at either a LIBOR-based rate or a prime-based rate, at the Company s option, plus a specified margin. The Company must pay a commitment fee of 0.250% to 0.375% per year on unused availability under the bank credit facility. The Company has used borrowings under the facility to facilitate the Forest Merger and acquisition of MGOM, and has used and may use borrowings under the facility for general corporate purposes.

As of December 31, 2008 and 2007, $570.0 million and $179.0 million, respectively, were outstanding under the credit facility, and the interest rate was 3.31% and 7.25%, respectively. In addition, as of December 31, 2008 five letters of credit totaling $7.2 million were outstanding, of which $4.2 million was required for plugging and abandonment obligations at certain of the Company s offshore fields.

The Company s payment and performance of its obligations under the credit facility (including any obligations under commodity and interest rate hedges entered into with facility lenders) are secured by liens upon substantially all of the assets of the Company and its subsidiaries, and guaranteed by its subsidiaries, other than MERI which is a co-borrower. The Company also is subject to various restrictive covenants and other usual and customary terms and conditions, including limits on additional debt, cash dividends and other restricted payments, liens, investments, asset dispositions, mergers and speculative hedging. Financial covenants under the 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, 2008.

Senior Notes On April 24, 2006, the Company sold and issued to eligible purchasers $300.0 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 $300.0 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.

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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.

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 do the following:

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.

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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.

Capitalized Interest For the period ended December 31, 2008 and 2007, capitalized interest totaled $9.7 million and $0.5 million, respectively.

Cash Interest Expense For the years ended December 31, 2008, 2007 and 2006 interest payments were $62.2 million, $49.1 million and $28.8 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 $185.0 million to $400.0 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 4. Stockholders Equity

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, 2008, 2007 and 2006.

	2008			**2007**			**2006**		
	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 (loss) income per share	$ (388,713)	87,491	$ (4.44)	$ 143,934	85,645	$ 1.68	$ 121,462	76,353	$ 1.59
					481	(0.01)		458	(0.01)

Effect of dilutive securities:									
Diluted net (loss) income earnings per share	$ (388,713)	87,491	$ (4.44)	$ 143,934	86,126	$ 1.67	$ 121,462	76,811	$ 1.58

Shares issuable upon exercise of options to purchase common stock and unvested shares of restricted stock that would have been anti-dilutive are excluded from the computation of diluted earnings per share. Due to our net loss for the year ended December 31, 2008, approximately 236,000 shares issuable upon exercise of stock options and 1,088,000 unvested shares of restricted stock were excluded from the computation of diluted earnings per share because the effect was anti-dilutive. Approximately 513,000 shares issuable upon exercise of stock options were excluded from the computation for year ended December 31, 2007 because the effect was anti-dilutive.

Authorized Stock The Company s certificate of incorporation, as amended, authorizes 200,000,000 shares of stock, of which 180,000,000 shares are common stock and 20,000,000 shares are preferred stock. In connection with the rights plan discussed below, the Company filed with the Delaware Secretary of State on October 13, 2008 a certificate of designations of Series A Junior Participating Preferred Stock which consists of 180,000 shares. As of December 31, 2008, no preferred stock had been issued.

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Rights Plan On October 12, 2008, Mariner s Board of Directors adopted a rights plan pursuant to which it declared and paid a dividend of one right (Right) for each outstanding share of the Company s common stock to holders of record at the close of business on October 23, 2008. The rights plan is intended to safeguard the interests of Mariner s stockholders by serving as a general deterrent to potentially unfair or coercive takeover practices, especially those exploiting market instability. The Rights generally would become exercisable if an acquiring party accumulates 10% or more of Mariner s common stock and entitle holders of Rights to purchase stock of either Mariner or an acquiring entity at half of market value. The Rights are governed by a Rights Agreement, dated as of October 12, 2008, between Mariner and Continental Stock Transfer & Trust Company, as Rights Agent (the Rights Agreement).

Each Right entitles the registered holder to purchase from Mariner under certain circumstances a unit consisting of one one-thousandth of a share of its Series A Junior Participating Preferred Stock, par value $0.0001 per share, at a purchase price of $75.00 per fractional share, subject to adjustment. The Rights are not exercisable (and are transferable only with Mariner s common stock) until a Distribution Date occurs (or they are earlier redeemed or expire), which generally occurs on the 10th day following a public announcement that a person or group of affiliated or associated persons (an Acquiring Person) has acquired beneficial ownership of 10% or more of Mariner s outstanding common stock or after the commencement or announcement of a tender offer or exchange offer which would result in any such person or group of persons acquiring such beneficial ownership. Until a Right is exercised, the holder thereof, as such, has no rights as a stockholder of the Company.

If a person becomes an Acquiring Person, holders of Rights will be entitled to purchase shares of Mariner s common stock for one-half its current market price, as defined in the Rights Agreement. This is referred to as a flip-in event under the Rights Agreement. After any flip-in event, all Rights that are beneficially owned by an Acquiring Person, or by certain related parties, will be null and void. Mariner s Board of Directors has the power to decide that a particular tender or exchange offer for all outstanding shares of Mariner s common stock is fair to, and otherwise in the best interests of, its stockholders. If the Board makes this determination, the purchase of shares under the offer will not be a flip-in event.

If, after there is an Acquiring Person, Mariner is acquired in a merger or other business combination transaction or 50% or more of its assets, earning power or cash flow are sold or transferred, each holder of a Right will have the right to purchase shares of the acquiring company s common stock at a price of one-half the current market price of that stock. This is referred to as a flip-over event under the Rights Agreement. An Acquiring Person will not be entitled to exercise its Rights, which will have become void.

The Rights expire on October 12, 2018 unless extended or earlier redeemed or exchanged by the Company. Mariner generally is entitled to redeem the Rights at $.001 per Right at any time until the tenth day after the Rights become exercisable. At any time after a flip-in event and before either a person becomes the beneficial owner of 50% or more of Mariner s outstanding common stock or a flip-over event, the Company s Board of Directors may decide to exchange the Rights for shares of Mariner s common stock on a one-for-one basis. Rights owned by an Acquiring Person, which will have become void, will not be exchanged.

Note 5. Share-Based Compensation

The Company accounts for its share-based compensation in accordance with SFAS No. 123(R), Share-Based Payment (SFAS 123(R)). Under SFAS 123(R), share-based compensation is measured at the grant date based on the calculated fair value of the award and is recognized as an expense over the requisite employee service period, which generally equals the vesting period of the grant. The Company determines share-based compensation expense for restricted stock and option grants equal to their fair value at the date of grant. The fair value then is amortized to share-based compensation expense over the applicable vesting period.

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Share-based compensation, including restricted stock and options under each of the Company s plans, for the years ended December 31, 2008, 2007 and 2006 was:

	Year Ended December 31		
	2008	2007	2006
	(In thousands)		
Share-based compensation included in:			
General and administrative expense	$ 21,017	$ 10,890	$ 10,227
Oil and natural gas properties under full cost method	2,956		
Total stock-based compensation	$ 23,973	$ 10,890	$ 10,227

Stock Incentive Plan The Company 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. As of December 31, 2008, 2,530,388 shares remained available for future issuance to participants under the Stock Incentive Plan. During the year ended December 31, 2008, 490,881 shares of restricted stock vested under the Stock Incentive Plan, resulting in withholding tax obligations. Plan participants can elect to have Mariner withhold and cancel shares of restricted stock to satisfy the associated tax withholding obligations. In such event, Mariner would be required to pay any tax withholding obligation in cash. As a result of such participant elections, the Company withheld an aggregate 143,842 shares in the year ended December 31, 2008 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. Mariner paid in cash the associated withholding taxes of approximately $4.3 million for the year ended December 31, 2008.

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, 2008, Rollover Options to purchase 32,543 shares of the Company s common stock remained outstanding, all of which were presently exercisable.

Equity Participation Plan The Company adopted an Equity Participation Plan, as amended, that provided for the one-time grant at the closing of its private equity placement on March 11, 2005 of 2,267,270 restricted shares of

Mariner s common stock to certain of its 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 Mariner s Stock Incentive Plan, as amended or restated from time to time, described below. The Company 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 its common stock. Therefore, Equity Participation Plan grantees did not pay any consideration for the common stock they received, and the Company 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

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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 the Company upon vesting to satisfy its 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 Mariner withhold and cancel shares of the restricted stock to satisfy our tax withholding obligations. In such events, Mariner would be required to pay any tax withholding obligation in cash. In 2006, as a result of such participant elections, the Company 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. the Company 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.

Restricted Stock Grants

Restricted stock granted under the Stock Incentive Plan is issued on the grant date, but is restricted as to transferability. Restricted stock grants generally vest over periods ranging from three to four years, except for grants made under the Stock Incentive Plan s Long-Term Performance-Based Restriced Stock Program discussed below. Compensation cost for all awards of restricted stock under the Stock Incentive Plan is based on the closing market price of Mariner s common stock on the date of grant. Stock-based compensation expense is based on the awards ultimately expected to vest, and has been reduced for estimated forfeitures.

The following table summarizes the status under the provisions of SFAS 123(R) of the Company s restricted stock, including Long-Term Performance Based Restricted Stock, at December 31, 2008 and the changes during the year then ended:

	Equity Instruments (thousands)	Weighted Average Fair Value	Aggregate Intrinsic Value ($ thousands)	Weighted Average Remaining Contractual Life (Years)
Unvested at January 1, 2008	1,484,552	$ 21.00	$ 31,182	
Granted	1,734,070	32.28	55,974	
Vested	(490,881)	20.96	(10,287)	
Forfeited	(29,815)	24.89	(742)	
Unvested at December 31, 2008	2,697,926	28.22	$ 76,127	7.79

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The following table shows a summary of the activity for unvested restricted stock awards under the Stock Incentive Plan, including Long-Term Performance Based Restricted Stock, during the years 2008, 2007 and 2006:

	Restricted Shares under the Stock Incentive Plan		
	2008	**2007**	**2006**
Total unvested shares at beginning of period: January 1	1,484,552	875,380	
Shares granted	1,734,070	906,104	907,371
Shares vested	(490,881)	(251,332)	(4,500)
Shares forfeited	(29,815)	(45,600)	(27,491)
Total unvested shares at end of period: December 31	2,697,926	1,484,552	875,380
Total shares vested at end of period: December 31	746,713	255,832	4,500
Available for future grant as options or restricted stock	2,530,388	4,072,801	4,862,132
Average fair value of shares granted during the period	$ 30.27	$ 21.73	$ 19.54

At December 31, 2008, unrecognized compensation expense under the Stock Incentive Plan for the unvested portion of restricted stock grants was $56.1 million. These costs are expected to be recognized over a weighted-average period of approximately four years. As of May 31, 2006, participants were fully vested in restricted stock granted under the Equity Participation Plan and no unrecognized compensation remains.

Long-Term Performance-Based Restricted Stock Program In June 2008, Mariner s Board of Directors adopted a Long-Term Performance-Based Restricted Stock Program (the Program) under the Stock Incentive Plan. Shares of restricted common stock subject to the Program were granted during the year ended December 31, 2008. Vesting of these shares is contingent, begins upon satisfaction of specified thresholds of $38.00 and $46.00 for the market price per share of Mariner s common stock, and continues in installments over five to seven years thereafter, assuming, in most instances, continued employment by Mariner. The fair value of restricted stock grants made under the Program is estimated using a Monte Carlo simulation. Stock-based compensation expense related to these restricted stock grants totaled $6.4 million for the 12 months ended December 31, 2008.

Weighted average fair values and valuation assumptions used to value the Long-Term Performance Based Restricted Stock grants for the year ended December 31, 2008 are as follows:

	Year Ended December 31, 2008
Weighted average fair value of grants	$ 33.73
Expected volatility	42.29%

Risk-free interest rate	4.57%
Dividend yield	0.00%
Expected life	10 years

Expected volatility is calculated based on the average historical stock price volatility of Mariner and a peer group as of December 31, 2008. The peer group consisted of the following seven independent oil and gas exploration and production companies: ATP Oil & Gas Corporation, Callon Petroleum Co., Energy Partners, Ltd., McMoRan Exploration Co., Plains Exploration & Production Company, Stone Energy Corporation, and W&T Offshore, Inc. The risk-free interest rate is determined at the grant date and is based on 10-year, zero-coupon government bonds with maturity equal to the contractual term of the awards, converted to a continuously compounded rate. The expected life is based upon the contractual terms of the restricted stock grants under the Program.

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Stock Option Grants

As of December 31, 2008, 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. Compensation cost for option awards under the Stock Incentive Plan is determined using a Black-Scholes valuation model. Stock-based compensation expense is based on the awards ultimately expected to vest and has been reduced for estimated forfeitures.

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, 2008:

	Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value(1) ($000)
Outstanding at beginning of year January 1, 2008	720,488	$ 13.82	$ (2,608)
Granted			
Exercised	(56,348)	13.18	168
Forfeited	(18,792)	13.90	69
Outstanding at end of year December 31, 2008	645,348	$ 13.88	$ (2,371)
Exercisable at end of year	645,348	$ 13.88	$ (2,371)

(1) Based upon the difference between the market price of the common stock on the last trading date of the year ($10.20) and the option exercise price of in-the-money options.

The intrinsic value of options exercised in the years ended December 31, 2008, 2007 and 2006 was $(2.4) million, $6.5 million and $4.6 million, respectively, and the Company received $0.7 million, $0.8 million and $0.7 million, respectively, upon the exercise of such options and a windfall tax deduction of approximately $0.3 million, $0.4 million and approximately $63,000 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, 2008:

Options Outstanding		Options Exercisable
	Weighted	

Exercise Price	Shares Subject to Outstanding Options	Average Remaining Contractual Life (Years)	Expected Term	Weighted Average Shares Exercisable
$9.67	660	5.08	6.08	660
$11.44	1,650	5.88	6.88	1,650
$11.59	30,233	5.94	6.94	30,233
$14.00	612,805	6.26	10.50	612,805
Total number of shares subject to options	645,348			645,348

Options generally vested 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 was $2.58. There were no options granted during 2007 and 2008. The fair value of each option award is estimated on the date of grant

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using the Black-Scholes option valuation model. The assumptions utilized in 2006 upon option grant are noted in the following table:

Black-Scholes Assumptions	**12 Months Ended December 31, 2006 Rollover Options**
Expected Term (years)	4.7
Risk Free Interest Rate	4.79%
Expected Volatility	35.00%
Dividend Yield	0.00%

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 the common share price of the peer group (identified above) for a period equal to the stock option s expected life. The risk-free rate is based 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.

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 be 4% of the lesser of the Company s operating income or total employee compensation and be allocated to each eligible participant pro rata to his or her compensation. The Company contributed $1.1 million, $0.9 million and $0.7 million for the years ended December 31, 2008, 2007 and 2006, respectively. 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 $3.6 million, $5.8 million and $2.0 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Note 7. Derivative Financial Instruments

Derivative Financial Instruments 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.

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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,		
	2008	2007	2006
	(In thousands)		
Cash (Loss) Gain on Settlements	$ (98,814)	$ 46,732	$ 11,273
(Loss) Gain on Hedge Ineffectiveness(1)	(1,995)	(1,655)	4,175
Non-cash Gain on hedges acquired(2)			17,523
Total	**$ (100,809)**	**$ 45,077**	**$ 32,971**

(1) Unrealized (loss) gain 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.

As of December 31, 2008, the Company had the following hedging activity outstanding:

Fixed Price Swaps	**Quantity**	**Weighted-Average Fixed Price**	**Fair Value Asset**
		(In thousands)	
Natural Gas (MMbtus)			
January 1 December 31, 2009	31,642,084	$ 8.48	$ 74,709
Crude Oil (Bbls)			
January 1 December 31, 2009	2,172,210	$ 76.15	47,220
Total			**$ 121,929**

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

Fixed Price Swaps	**Quantity**	**Weighted-Average Fixed Price**	**Fair Value Asset/(Liability)**

			(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**	**Fair Value Asset/(Liability)**
		(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)**

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As of February 20, 2009, there were no hedging transactions entered into subsequent to December 31, 2008 except as follows:

Period	Instrument Type	Quantity	Weighted Average Price
Natural Gas (MMbtus) 2009			
January 1 December 31	Fixed Price Swaps	19,665,000	$ 6.19 Fixed
Crude Oil (Bbls) 2009			
February 1 December 31	Fixed Price Swaps	977,047	$ 51.42 Fixed

The Company has reviewed the financial strength of its counterparties and believes the credit risk associated with these swaps and costless collars is minimal. Hedges with counterparties that are lenders under the Company s bank credit facility are secured under the bank credit facility.

As of December 31, 2008, the Company expected to realize within the next 12 months approximately $121.9 million in net gains resulting from hedging activities that are recorded in accumulated other comprehensive income. These hedging gains were expected to be realized as an increase of $47.2 million to oil revenues and an increase of $74.7 million to natural gas revenues. On January 29, 2008, the Company liquidated crude oil fixed price swaps in respect of 977 thousand barrels in exchange for a cash payment of $10.1 million and installment payments of $13.5 million to be received monthly throughout 2009.

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, 2008 are as follows (in thousands):

2009	$ 2,240
2010	2,532
2011	2,499
2012	2,414
2013 and thereafter	11,961
Total	**$ 21,646**

Rental expense, before capitalization, was approximately $2.1 million for 2008, $1.4 million for 2007 and $1.2 million for 2006.

Other Commitments In the ordinary course of business, the Company enters into long-term commitments to purchase seismic data. The minimum annual payments under these contracts are $2.3 million and $0.7 million in 2009 and 2010 respectively. At December 31, 2008, the Company also has a long-term commitment for contracted drilling services of $183.9 million, of which $124.5 million and $59.4 million is due in 2009 and 2010, respectively.

Current Insurance Against Hurricanes

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. Mariner s coverage is subject to a $10.0 million per-occurrence deductible for our assets and a $250.0 million per-occurrence loss limit. However, if a single event causes losses to all OIL-insured assets in excess of $750.0 million, amounts covered for such losses will be reduced on a pro-rata basis among OIL members.

In addition to Mariner s primary coverage through OIL, it also maintains commercial difference in conditions insurance that would apply (with no additional deductible) once its limits with OIL are exhausted,

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as well as partial business interruption insurance covering certain of its significant producing fields as well as certain other fields situated in hurricane prone areas. Mariner s 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. Mariner s commercial policy expires annually on June 1, and is subject to a general limit of $100.0 million per occurrence and in the case of named windstorms, a combined annual aggregate limit of $100.0 million covering both property damage and business interruption.

The Company accrued approximately $36.0 million as of December 31, 2008, for an OIL premium contingency. As part of its OIL membership, the Company is obligated to pay a withdrawal premium if it elects to withdraw from OIL. Mariner does not anticipate withdrawing from OIL; however, due to the contingency, OIL calculates a potential withdrawal premium annually based on past losses and Mariner accrues a liability for the potential premium. OIL requires smaller members to provide a letter of credit or other acceptable security in favor of OIL to secure payment of the withdrawal premium. Acceptable security has included a letter of credit or a security agreement pursuant to which a member grants OIL a security interest in certain claim proceeds payable by OIL to the member. Mariner anticipates that it will enter into such a security agreement, granting to OIL a security interest in a portion of Mariner s Hurricane Ike claim proceeds payable by OIL. Mariner would have the ability to replace the security agreement with a letter of credit or other acceptable security in favor of OIL.

Hurricane Ike (2008)

In 2008, the Company s operations were adversely affected by Hurricane Ike. The hurricane resulted in shut-in and delayed production as well as facility repairs and replacement expenses. The Company is evaluating the nature and extent of damage resulting from the hurricane. With respect to Hurricane Ike, Mariner s OIL coverage has a $10.0 million per occurrence deductible and a $250.0 million per occurrence limit, subject to an industry-wide loss limit of $750.0 million per occurrence. To the extent that aggregate claims exceed the OIL industry-wide loss limit per-occurrence, Mariner expects its insurance recovery would be reduced pro-rata with all other competing claims from Hurricane Ike and the shortfall covered by its excess insurance, subject to policy limits. Due to the magnitude of Hurricane Ike and the complexity of the insurance claims being processed by the insurance industry, the timing of the Company s ultimate insurance recovery cannot be ascertained. Mariner expects to maintain a potentially significant insurance receivable through 2010 while it actively pursues settlement of its Hurricane Ike claims to minimize the impact to its working capital and liquidity.

Hurricanes Katrina and Rita (2005)

In 2005, the Company s operations were adversely affected by Hurricanes Katrina and Rita, resulting in substantial shut-in and delayed production, as well as necessitating extensive facility repairs and hurricane-related abandonment operations. Since 2005, the Company has incurred approximately $182.2 million in hurricane expenditures resulting from Hurricanes Katrina and Rita, of which $127.7 million were capitalized expenditures and $54.5 million were hurricane-related abandonment costs.

Applicable insurance for the Company s Hurricane Katrina and Rita claims with respect to the Gulf of Mexico assets previously acquired from Forest is provided by OIL. Mariner s coverage for the former Forest properties is subject to a deductible of $5.0 million per occurrence and a $1.0 billion industry-wide loss limit per occurrence. OIL has advised the Company that the aggregate claims resulting from each of Hurricanes Katrina and Rita are expected to exceed the $1.0 billion per occurrence loss limit and that therefore, Mariner s insurance recovery is expected to be reduced pro-rata with all other competing claims from the storms. During 2008, the Company settled its Katrina and Rita claims with its excess insurance providers for a one-time payment of $48.5 million. The insurance coverage for Mariner s legacy properties is subject to a $3.75 million deductible.

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As of December 31, 2008, the Company had recovered $14.6 million from OIL and $48.5 million from its conventional carriers in respect of Hurricanes Katrina and Rita, and the insurance receivable balance for the Company s claims for those hurricanes was approximately $25.2 million, of which $18.2 million is classified as a Long-term asset. Due to the magnitude of the storms and the complexity of the insurance claims being processed by the insurance industry, the timing of the Company s ultimate insurance recovery cannot be assured. However, Mariner expects to recover substantially all of its outstanding OIL claims in respect of Hurricanes Katrina and Rita by 2010. Any differences between insurance recoveries and insurance receivables will be recorded as adjustments to oil and natural gas properties.

MMS 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. Section 304 of the RRA relieves lessees of the obligation to pay royalties on certain leases until after a designated volume has been produced. Four of these leases held by Mariner and two held by MERI that are producing or have produced contain lease language (inserted by the MMS) that conditions royalty relief on commodity prices remaining below specified thresholds. Since 2000, commodity prices have exceeded some of the predetermined thresholds, except in 2002. In May 2006 and September 2008, the MMS issued orders asserting that the price thresholds had been exceeded in calendar years 2000, 2001, and each of the years from 2003 through 2007, and, accordingly, that royalties were due under such leases on oil and gas produced in those years. The potential liability of MERI under its leases relate to production from the leases commencing July 1, 2005, the effective date of Mariner s acquisition of MERI. Mariner and MERI believe that the MMS did not have the statutory authority to include commodity price threshold language in the leases governed by Section 304 of the RRA and accordingly have withheld payment of royalties. Mariner and MERI have challenged the MMS s authority in pending administrative appeals for those leases for which the MMS has issued orders to pay.

The enforceability of the price threshold provisions in leases granted pursuant to Section 304 of the RRA is currently being litigated in several administrative appeals filed by other companies in addition to Mariner, as well as in *Kerr-McGee Oil & Gas Corp. v. Allred*, No. 08-30069 (5th Cir.). In the *Kerr-McGee* litigation, the district court in the Western District of Louisiana granted Kerr-McGee s motion for summary judgment, ruling that the price threshold provisions are unlawful and unenforceable under Section 304 of the RRA. *Kerr-McGee Oil & Gas Corp. v. Allred*, No. 2:06 CV 0439 (W.D. La.) (Mem. Ruling filed Oct. 30, 2007). The Department of the Interior appealed that judgment to the United States Court of Appeals for the Fifth Circuit. On January 12, 2009, the Fifth Circuit affirmed the district court s judgment that the price provisions are unlawful based on Section 304 of the RRA. *Kerr-McGee Oil & Gas Corp. v. U.S. Dep t of Interior*, F.3d , 2009 WL 57883 (5th Cir. Jan. 12, 2009). Until the appeals process is complete, Mariner will continue to monitor the case. Given the judicial history of the case, Mariner determined that as of December 31, 2008, it no longer will record a liability for its estimated exposure to the MMS on leases granted to Mariner pursuant to Section 304 of the RRA. At December 31, 2008, this liability would have been $57.3 million, including interest. In addition, as of December 31, 2008, Mariner began including in its estimated proved reserves those reserves attributable to these RRA Section 304 leases which, at December 31, 2008, was approximately 18.1 Bcfe.

Litigation The Company, in the ordinary course of business, is a claimant and/or a defendant in various legal proceedings, including proceedings as to which the Company has insurance coverage and those that may involve the filing of liens against the Company or its assets. The Company does not consider its exposure in these proceedings, individually or in the aggregate, to be material.

Letters of Credit 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, 2008, five such letters of credit totaling $7.2 million were outstanding of which $4.2 million is required for plugging and abandonment obligations at certain of Mariner s offshore fields.

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On March 2, 2006, Mariner obtained a dedicated letter of credit under its bank credit facility. It was not included as a use of the borrowing base. The dedicated letter of credit was issued in favor of Forest to secure performance of our obligation to drill and complete 150 wells under a drill-to-earn program. 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 January 2008, the dedicated letter of credit had been reduced to zero and cancelled as all 150 wells had been drilled and completed as of December 31, 2007. The dedicated letter of credit balance as of December 31, 2007 was $3.2 million.

Note 9. Fair Value Measurement

Certain of Mariner s assets and liabilities are reported at fair value in the accompanying Consolidated Balance Sheets. Such assets and liabilities include amounts for both financial and nonfinancial instruments. The carrying values of cash and cash equivalents, accounts receivable and accounts payable (including income taxes payable and accrued expenses) approximated fair value at December 31, 2008 and December 31, 2007. These assets and liabilities are not included in the following tables.

SFAS 157 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. As presented in the table below, the hierarchy consists of three broad levels. Level 1 inputs on the hierarchy consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are market-based and are directly or indirectly observable but not considered Level 1 quoted prices, including quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; or valuation techniques whose inputs are observable. Where observable inputs are available, directly or indirectly, for substantially the full term of the asset or liability, the instrument is categorized in Level 2. Level 3 inputs are unobservable (meaning they reflect Mariner s own assumptions regarding how market participants would price the asset or liability based on the best available information) and therefore have the lowest priority. A financial instrument s level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Mariner believes it uses appropriate valuation techniques based on the available inputs to measure the fair values of its assets and liabilities.

SFAS 157 requires a credit adjustment for non-performance in calculating the fair value of financial instruments. The credit adjustment for derivatives in an asset position is determined based on the credit rating of the counterparty and the credit adjustment for derivatives in a liability position is determined based on Mariner s credit rating.

The following table provides fair value measurement information for the Company s derivative financial instruments as of December 31, 2008.

	As of December 31, 2008		
	Fair Value Measurements Using:		
	Quoted Prices	Significant Other Observable	Significant Unobservable

Derivative Financial Instruments	Carrying Amount	Total Fair Value	in Active Markets (Level 1) (In thousands)	Inputs (Level 2)	Inputs (Level 3)
Natural gas and crude oil fixed price swaps Short Term	$ 121,929	$ 121,929	$	$ 121,929	$
Natural gas and crude oil fixed price swaps Long Term					
Total	$ 121,929	$ 121,929	$	$ 121,929	$

The following methods and assumptions were used to estimate the fair values of Mariner s derivative financial instruments in the table above.

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MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2008, 2007 and 2006

Level 2 Fair Value Measurements

The fair values of the natural gas and crude oil fixed price swaps are estimated using internal discounted cash flow calculations based upon forward commodity price curves, terms of each contract, and a credit adjustment based on the credit rating of the Company and its counterparties as of December 31, 2008.

Level 3 Fair Value Measurements

The fair values of the natural gas and crude oil costless collars are estimated valuations using the Black-Scholes valuation model based upon the forward commodity price curves, implied volatilities of commodities, and a credit adjustment based on Mariner s credit rating as of December 31, 2008. The following table provides fair value measurement information for the Company s Level 3 financial instruments as of December 31, 2008.

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)

	For the Twelve Months Ended December 31, 2008 (In thousands)	
Fair value of costless collars, beginning of period	$	(4,058)
Total gains/(losses):		
Included in natural gas and oil revenues (realized/unrealized)		(22,477)
Included in other comprehensive loss (realized/unrealized)		4,058
Purchases, issuances, and settlements, net		22,477
Transfers in and/or out of Level 3		
Fair value of costless collars, end of period	$	
The amount of net gains/(losses) for the period included in earnings attributable to the change in net unrealized losses relating to costless collars still held at the reporting date	$	

Note 10. Income Taxes

The components of the federal income tax provision are:

	For the Year Ended December 31,		
	2008	2007	2006
	(In thousands)		

Current	$ 1,939	$	$
Deferred	(50,172)	77,324	67,344
Total (Benefit) Provision for Income Taxes	$ (48,223)	$ 77,324	$ 67,344

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2008, 2007 and 2006

The following table sets forth a reconciliation of the statutory federal income tax with the income tax provision:

	Year Ended December 31, 2008		2007		2006	
	(In thousands, except percentages)					
Income before taxes and minority interest	$ (436,748)		$ 221,259		$ 188,806	
Income tax expense computed at statutory rates	$ (152,862)	35.0%	$ 77,440	35.0%	$ 66,081	35.0%
State tax expense, net of the federal benefit	$ (619)	(0.2)%	2,452	1.1%	946	0.5%
Forest purchase price adjustment			(2,034)	(0.9)%		
Goodwill Impairment	$ 103,460	(23.7)%				
Other	$ 1,798	(0.5)%	(534)	(0.3)%	317	0.2%
Total (Benefit) Provision for Income Taxes	$ (48,223)	11.0%	$ 77,324	34.9%	$ 67,344	35.7%

Federal income taxes paid by the Company in the year ended December 31, 2008, 2007 and 2006 were $1.73 million, $0.6 million and $0.0 million, respectively.

The Company s deferred tax position reflects the net tax effects of the temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax reporting. Significant components of the deferred tax assets and liabilities are as follows:

	At December 31, 2008	2007
	(In thousands)	
Current Deferred Tax Assets:		
Employee share-based compensation	$ 2,484	$ 3,562
Net operating loss carry forwards (current)	17,591	
Total current deferred tax assets	20,075	3,562
Long-Term Deferred Tax Assets:		
Net operating loss carry forwards	154,711	215,834
Alternative minimum tax credit	3,342	1,607

Valuation allowance	(408)	(468)
Reserve accruals	439	460
Other	4,499	47
Total net deferred tax assets	162,583	217,480
Current Deferred Tax Liabilities:		
Deferred gain		(808)
Other comprehensive income-derivative instruments	(43,223)	3,478
Other		
Total current deferred tax liabilities	(43,223)	2,670
Long-Term Deferred Tax Liabilities:		
Deferred gain		(74)
Other comprehensive income-derivative instruments		8,723
Differences between book and tax basis properties	(472,718)	(560,566)
Texas margins tax	(98)	(189)
Louisiana franchise tax	(9,533)	(9,357)
Other		35
Total long-term deferred tax liabilities	(482,349)	(561,428)
Total net deferred liability	$ (342,914)	$ (337,716)

MARINER ENERGY, INC.

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For the Years Ended December 31, 2008, 2007 and 2006

At December 31, 2008, the Company had federal and state net operating loss carry forwards of approximately $500.8 million and $21.0 million, respectively, which will expire in varying amounts between 2019 and 2027 and are subject to certain limitations on an annual basis. A valuation allowance has been established against state net operating losses where it is more likely than not that, such losses will expire before they are utilized. The current portion of deferred tax liabilities is $23.1 million.

The Company adopted FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109 (FIN 48), which clarifies the accounting and disclosure for uncertainty in tax positions, as defined. FIN 48 seeks to reduce the diversity in practice associated with certain aspects of the recognition and measurement related to accounting for income taxes. The Company adopted FIN 48 and applied the guidance of FIN 48-1 as of January 1, 2007. As of the adoption date, the Company did not record a cumulative effect adjustment related to the adoption of FIN 48 or have any gross unrecognized tax benefit. At December 31, 2008, the Company did not have any FIN 48 liability or gross recognized tax benefit.

The Company has incurred changes of control as defined by the Internal Revenue Code Section 382 (Section 382). Accordingly, the rules of Section 382 will limit the utilization of our net operating losses. The limitation is determined by multiplying the value of the stock immediately before the ownership change by the applicable long-term exempt rate. It is estimated that $57.3 million of net operating losses will be subject to an annual limitation of approximately $4.0 million, and an estimated $72.8 million of net operating losses will be subject to an annual limitation of approximately $33.0 million. Any unused annual limitation may be carried over to later years. The amount of the limitation may under certain circumstances be increased by the built-in gains in assets held by us at the time of the change that are recognized in the five-year period after the change.

Deferred tax assets relating to tax benefits of employee share-based compensation have been reduced to reflect stock options exercised and restricted stock that vested in fiscal 2008. Some exercises and vestings resulted in tax deductions in excess of previously recorded benefits based on the option value at the time of grant (windfalls). Although these additional tax benefits or windfalls are reflected in net operating tax carry forwards pursuant to SFAS 123(R) Share-Based Payment , the additional tax benefit associated with the windfall is not recognized until the deduction reduces taxes payable. Accordingly, since the tax benefit does not reduce our current taxes payable in fiscal 2008 due to net operating loss carry forwards, these windfall tax benefits are not reflected in our net operating losses in deferred tax assets for fiscal 2008. Windfalls included in net operating loss carry forwards but not reflected in deferred tax assets for fiscal 2008 are $9.2 million.

Note 11. Segment Information

The FASB issued SFAS No. 131 Disclosures about Segments of an Enterprise and Related Information (SFAS 131), which establishes standards for reporting information about operating segments. Operating segments are defined as components of an enterprise that engage in activities from which it may earn revenues and incur expenses. Separate financial information is available and this information is regularly evaluated by the chief decision maker for the purpose of allocating resources and assessing performance.

We measure financial performance as a single enterprise, allocating capital resources on a project-by-project basis across our entire asset base to maximize profitability. We utilize a company-wide management team that administers all enterprise operations encompassing the exploration, development and production of natural gas and oil. All operations are located in the United States. Inasmuch as we are one enterprise, we do track basic operational data by area, and do not maintain comprehensive financial statement information by area.

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2008, 2007 and 2006

Note 12. Quarterly Financial Information (Unaudited)

The following table presents Mariner s unaudited quarterly financial information for 2008 and 2007:

	Quarter Ended 2008			
	December 31	September 30	June 30	March 31
	(In thousands, except share data)			
Total revenues	$ 237,268	$ 317,890	$ 429,452	$ 315,897
Operating (loss) income(2)	(839,221)	117,668	208,186	131,655
(Loss) Income before taxes and minority interest(2)	(841,592)	100,530	190,904	113,410
(Benefit) Provision for income taxes(2)	(192,672)	35,839	67,416	41,194
Net (loss) income(2)	$ (648,920)	$ 64,691	$ 123,390	$ 72,126
Earnings per share:(1)				
Net (loss) income per share basic(2)	$ (7.41)	$ 0.74	$ 1.40	$ 0.83
Net (loss) income per share diluted(2)	$ (7.41)	$ 0.73	$ 1.39	$ 0.82
Weighted average shares outstanding basic	87,622,740	87,595,792	87,983,902	87,293,730
Weighted average shares outstanding diluted	87,622,740	88,183,715	88,828,904	88,012,901

	Quarter Ended 2007			
	December 31	September 30	June 30	March 31
	(In thousands, except share data)			
Total revenues	$ 253,595	$ 196,484	$ 213,081	$ 211,605
Operating income	91,254	51,196	63,218	63,042
Income before taxes and minority interest	77,971	37,668	49,203	56,417
Provision for income taxes	27,729	15,140	16,245	18,210
Net income	$ 50,241	$ 22,528	$ 32,958	$ 38,207
Earnings per share:(1)				
Net income per share basic	$ 0.59	$ 0.26	$ 0.38	$ 0.45
Net income per share diluted	$ 0.58	$ 0.26	$ 0.38	$ 0.45
Weighted average shares outstanding basic	85,744,760	85,701,696	85,627,433	85,515,561
Weighted average shares outstanding diluted	86,276,871	85,964,108	85,905,296	85,704,529

(1) The sum of quarterly net income per share may not agree with total year net income per share, as each quarterly computation is based on the weighted average shares outstanding.

(2) Fourth quarter amounts include $575.6 million in full cost ceiling test impairment, $295.6 million in goodwill impairment, $15.3 million in other property impairment, $21.6 million contingent withdrawl premium relating to Mariner s participation in OIL, and $46.5 million release of suspended revenue associated with the disputed MMS Royalty Relief liability.

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MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2008, 2007 and 2006

Note 13. Supplemental Guarantor Information

On April 30, 2007, the Company sold and issued $300 million aggregate principal amount of its 8% Notes. On April 24, 2006, the Company sold and issued to eligible purchasers $300 million aggregate principal amount of its 71/2% Notes. The Notes are jointly and severally guaranteed on a senior unsecured basis by the Company s existing and future domestic subsidiaries (Subsidiary Guarantors). The guarantees are full and unconditional and the guarantors are wholly-owned. 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.

The following information sets forth our Consolidating Balance Sheets as of December 31, 2008 and 2007, our Condensed Consolidating Statements of Operations for the years ended December 31, 2008, 2007 and 2006, and our Condensed Consolidating Statements of Cash Flows for the years ended December 31, 2008, 2007 and 2006. Investments in our subsidiaries are accounted for on the consolidation method; accordingly, entries necessary to consolidate the Parent Company and the Subsidiary Guarantors are reflected in the eliminations column. In the opinion of management, separate complete financial statements of the Subsidiary Guarantors would not provide additional material information that would be useful in assessing their financial composition.

Mariner accounts for investments in its subsidiaries using the equity method of accounting; accordingly, entries necessary to consolidate Mariner, the parent company, and its Subsidiary Guarantors are reflected in the eliminations column. In the opinion of management, separate complete financial statements of the Subsidiary Guarantors would not provide additional material information that would be useful in assessing their financial composition.

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2008, 2007 and 2006

MARINER ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING BALANCE SHEET
December 31, 2008
(In thousands except share data)

	Parent Company	Subsidiary Guarantors	Eliminations	Consolidated Mariner Energy, Inc.
Current Assets:				
Cash and cash equivalents	$ 2,851	$ 400	$	$ 3,251
Receivables, net of allowances	157,362	62,558		219,920
Insurance receivables	5,886	7,237		13,123
Derivative financial instruments	121,929			121,929
Intagible assets	2,334	19		2,353
Prepaid expenses and other	12,923	1,454		14,377
Total current assets	303,285	71,668		374,953
Property and Equipment:				
Proved oil and gas properties, full-cost method	2,181,238	2,266,908		4,448,146
Unproved properties, not subject to amortization	185,012	16,109		201,121
Total oil and gas properties	2,366,250	2,283,017		4,649,267
Other property and equipment	33,351	19,764		53,115
Accumulated depreciation, depletion and amortization	(915,887)	(856,618)		(1,772,505)
Total property and equipment, net	1,483,714	1,446,163		2,929,877
Investment in Subsidiaries	704,971		(704,971)	
Intercompany Receivables	123,142	113,064	(236,206)	
Intercompany Note Receivable	176,200		(176,200)	
Insurance Receivables	3,924	18,208		22,132
Other Assets, net of amortization	64,726	1,105		65,831
TOTAL ASSETS	$ 2,859,962	$ 1,650,208	$ (1,117,377)	$ 3,392,793
Current Liabilities:				
Accounts payable	$ 3,837	$	$	$ 3,837
Accrued liabilities	72,743	35,072		107,815
Accrued capital costs	144,710	51,123		195,833

Deferred Tax Liability	23,148			23,148
Abandonment liability	1,554	80,810		82,364
Accrued interest	12,567			12,567
Total current liabilities	258,559	167,005		425,564
Long-Term Liabilities:				
Abandonment liability	56,920	268,960		325,880
Deferred income tax	110,431	209,335		319,766
Intercompany payables	113,064	123,142	(236,206)	
Long-term debt	1,170,000			1,170,000
Other long-term liabilities	30,668	595		31,263
Intercompany not payable		176,200	(176,200)	
Total long-term liabilities	1,481,083	778,232	(412,406)	1,846,909
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, 2008				
Common stock, $.0001 par value; 180,000,000 shares authorized, 88,846,073 shares issued and outstanding at December 31, 2008	9	5	(5)	9
Additional paid-in-capital	1,071,347	886,143	(886,143)	1,071,347
Partner capital		30,646	(30,646)	
Accumulated other comprehensive income	78,181			78,181
Accumulated retained earnings	(29,217)	(211,823)	211,823	(29,217)
Total stockholders equity	1,120,320	704,971	(704,971)	1,120,320
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 2,859,962	$ 1,650,208	$ (1,117,377)	$ 3,392,793

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MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
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MARINER ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING BALANCE SHEET
December 31, 2007
(In thousands except share data)

	Parent Company	Subsidiary Guarantors	Eliminations	Consolidated Mariner Energy, Inc.
Current Assets:				
Cash and cash equivalents	$ 18,589	$	$	$ 18,589
Receivables, net of allowances	64,714	93,060		157,774
Insurance receivables	3,950	22,733		26,683
Derivative financial instruments	11,863			11,863
Intangible assets	16,209	1,000		17,209
Prepaid expenses and other	9,105	1,525		10,630
Deferred tax asset	6,232			6,232
Total current assets	130,662	118,318		248,980
Property and Equipment:				
Proved oil and gas properties, full-cost method	1,469,989	1,648,284		3,118,273
Unproved properties, not subject to amortization	40,025	430		40,455
Total oil and gas properties	1,510,014	1,648,714		3,158,728
Other property and equipment	15,495	50		15,545
Accumulated depreciation, depletion and amortization	(403,159)	(350,920)		(754,079)
Total property and equipment, net	1,122,350	1,297,844		2,420,194
Investment in Subsidiaries	1,014,548		(1,014,548)	
Intercompany Receivables	46,015		(46,015)	
Intercompany Note Receivable	176,200		(176,200)	
Restricted Cash		5,000		5,000
Goodwill		295,598		295,598
Insurance Receivables	2,663	54,261		56,924
Derivative Financial Instruments	691			691
Other Assets, net of amortization	55,607	641		56,248
TOTAL ASSETS	$ 2,548,736	$ 1,771,662	$ (1,236,763)	$ 3,083,635

Current Liabilities:				
Accounts payable	$ 1,064	$	$	$ 1,064
Accrued liabilities	70,467	26,469		96,936
Accrued capital costs	85,839	73,171		159,010
Abandonment liability	4,383	26,602		30,985
Accrued interest	7,726			7,726
Derivative financial instruments	19,468			19,468
Total current liabilities	188,947	126,242		315,189
Long-Term Liabilities:				
Abandonment liability	49,827	141,194		191,021
Deferred income tax	80,095	263,853		343,948
Derivative financial instruments	25,343			25,343
Intercompany payables		46,015	(46,015)	
Long-term debt	779,000			779,000
Other long-term liabilities	34,506	3,609		38,115
Intercompany note payable		176,200	(176,200)	
Total long-term liabilities	968,771	630,871	(222,215)	1,377,427
Commitments and Contingencies (see Note 8)				
Minority Interest		1		1
Stockholders Equity:				
Preferred stock, $.0001 par value; 20,000,000 shares authorized, no shares issued and outstanding at December 31, 2007				
Common stock, $.0001 par value; 180,000,000 shares authorized, 87,229,312 shares issued and outstanding at December 31, 2007	9	5	(5)	9
Additional paid-in-capital	1,054,089	886,142	(886,142)	1,054,089
Partner capital		6,000	(6,000)	
Accumulated other comprehensive (loss)	(22,576)			(22,576)
Accumulated retained earnings	359,496	122,401	(122,401)	359,496
Total stockholders equity	1,391,018	1,014,548	(1,014,548)	1,391,018
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 2,548,736	$ 1,771,662	$ (1,236,763)	$ 3,083,635

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2008, 2007 and 2006

MARINER ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
Year Ended December 31, 2008
(In thousands)

	Parent Company	Subsidiary Guarantors	Eliminations	Consolidated Mariner Energy, Inc.
Revenues:				
Natural gas	$ 358,585	$ 383,785	$	$ 742,370
Oil	239,842	180,036		419,878
Natural gas liquids	56,307	29,408		85,715
Other revenues	41,851	10,693		52,544
Total revenues	696,585	603,922		1,300,507
Costs and Expenses:				
Operating expenses	137,917	126,915		264,832
General and administrative	58,617	1,996		60,613
Depreciation, depletion and amortization	251,783	215,482		467,265
Full cost ceiling test impairment	266,326	309,281		575,607
Goodwill impairment		295,598		295,598
Other property impairment		15,252		15,252
Other miscellaneous expense	2,538	514		3,052
Total costs and expenses	717,181	965,038		1,682,219
OPERATING LOSS	(20,596)	(361,116)		(381,712)
Earnings of Affiliates	(334,223)		334,223	
Other Income/(Expenses):				
Interest income	10,239	84	(8,961)	1,362
Interest expense, net of amounts capitalized	(56,206)	(9,153)	8,961	(56,398)
Loss Before Taxes and Minority Interest	(400,786)	(370,185)	334,223	(436,748)
Benefit for Income Taxes	12,073	36,150		48,223
Minority Interest		(188)		(188)
NET LOSS	$ (388,713)	$ (334,223)	$ 334,223	$ (388,713)

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
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MARINER ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
Year Ended December 31, 2007
(In thousands)

	Parent Company	Subsidiary Guarantors	Eliminations	Consolidated Mariner Energy, Inc.
Revenues:				
Natural gas	$ 266,418	$ 268,119	$	$ 534,537
Oil	146,909	137,496		284,405
Natural gas liquids	30,513	23,679		54,192
Other revenues	1,491	140		1,631
Total revenues	445,331	429,434		874,765
Costs and Expenses:				
Operating expenses	59,232	106,377		165,609
General and administrative	43,004	8,060		51,064
Depreciation, depletion and amortization	175,147	209,174		384,321
Other miscellaneous expense	2,010	3,051		5,061
Total costs and expenses	279,393	326,662		606,055
OPERATING INCOME	165,938	102,772		268,710
Earnings of Affiliates	63,440		(63,440)	
Other Income/(Expenses):				
Interest income	15,611	15	(14,223)	1,403
Interest expense, net of amounts capitalized	(54,302)	(14,586)	14,223	(54,665)
Other income		5,811		5,811
Income Before Taxes and Minority Interest	190,687	94,012	(63,440)	221,259
Provision for Income Taxes	(46,753)	(30,571)		(77,324)
Minority Interest		(1)		(1)
NET INCOME	$ 143,934	$ 63,440	$ (63,440)	$ 143,934

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MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2008, 2007 and 2006

MARINER ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
Year Ended December 31, 2006
(In thousands)

	Parent Company	Subsidiary Guarantors	Eliminations	Consolidated Mariner Energy, Inc.
Revenues:				
Natural gas	$ 185,175	$ 227,792	$	$ 412,967
Oil	120,269	82,475		202,744
Natural gas liquids	21,593	18,914		40,507
Other revenues	3,287			3,287
Total revenues	330,324	329,181		659,505
Costs and Expenses:				
Operating expenses	41,569	55,775		97,344
General and administrative expense	35,740	6,277		42,017
Depreciation, depletion and amortization	128,413	163,767		292,180
Other miscellaneous expense	473	21		494
Total costs and expenses	206,195	225,840		432,035
OPERATING INCOME	124,129	103,341		227,470
Earnings of Affiliates	58,961		(58,961)	
Other Income/(Expense):				
Interest income	8,737	1	(7,753)	985
Interest expense, net of amounts capitalized	(35,714)	(11,688)	7,753	(39,649)
Income Before Taxes	156,113	91,654	(58,961)	188,806
Provision for Income Taxes	(34,651)	(32,693)		(67,344)
NET INCOME	$ 121,462	$ 58,961	$ (58,961)	$ 121,462

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MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2008, 2007 and 2006

MARINER ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
Year Ended December 31, 2008
(In thousands)

	Parent Company	Subsidiary Guarantors	Consolidated Mariner Energy, Inc.
Net cash provided by operating activities	$ 430,526	$ 431,491	$ 862,017
Cash flow from investing activities:			
Acquisitions and additions to property and equipment	(793,948)	(426,119)	(1,220,067)
Additions to other property and equipment	(15,099)	(34,618)	(49,717)
Other investing activities		5,000	5,000
Net cash used in investing activities	(809,047)	(455,737)	(1,264,784)
Cash flow from financing activities:			
Credit facility borrowings	1,268,000		1,268,000
Credit facility repayments	(877,000)		(877,000)
Other financing activities	(28,217)	24,646	(3,571)
Net cash provided by financing activities	362,783	24,646	387,429
(Decrease) Increase in Cash and Cash Equivalents	(15,738)	400	(15,338)
Cash and Cash Equivalents at Beginning of Period	18,589		18,589
Cash and Cash Equivalents at End of Period	$ 2,851	$ 400	$ 3,251

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MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2008, 2007 and 2006

MARINER ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
Year Ended December 31, 2007
(In thousands)

	Parent Company	Subsidiary Guarantors	Consolidated Mariner Energy, Inc.
Net cash provided by operating activities	$ 282,664	$ 253,449	$ 536,113
Cash flow from investing activities:			
Acquisitions and additions to property and equipment	(527,926)	(146,786)	(674,712)
Property conveyances	2,988	1,114	4,102
Other investing activities	26,830	1	26,831
Net cash used in investing activities	(498,108)	(145,671)	(643,779)
Cash flow from financing activities:			
Credit facility borrowings	564,000		564,000
Credit facility repayments	(739,000)		(739,000)
Proceeds from note offering	300,000		300,000
Other financing activities	99,454	(107,778)	(8,324)
Net cash provided by (used in) financing activities	224,454	(107,778)	116,676
Increase in Cash and Cash Equivalents	9,010		9,010
Cash and Cash Equivalents at Beginning of Period	9,579		9,579
Cash and Cash Equivalents at End of Period	$ 18,589	$	$ 18,589

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MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2008, 2007 and 2006

MARINER ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
Year Ended December 31, 2006
(In thousands)

	Parent Company	Subsidiary Guarantors	Consolidated Mariner Energy, Inc.
Net cash provided by operating activities	$ 191,225	$ 85,936	$ 277,161
Cash flow from investing activities:			
Acquisitions and additions to property and equipment	(330,298)	(212,283)	(542,581)
Property conveyances	33,829		33,829
Other investing activities	(31,830)	(20,808)	(52,638)
Net cash used in investing activities	(328,299)	(233,091)	(561,390)
Cash flow from financing activities:			
Credit facility borrowings	682,000		682,000
Credit facility repayments	(480,000)		(480,000)
Debt and working capital acquired from Forest Energy Resources, Inc.		(176,200)	(176,200)
Proceeds from note offering	300,000		300,000
Other financing activities	(359,903)	323,355	(36,548)
Net cash provided by financing activities	142,097	147,155	289,252
Increase in Cash and Cash Equivalents	5,023		5,023
Cash and Cash Equivalents at Beginning of Period	4,556		4,556
Cash and Cash Equivalents at End of Period	$ 9,579	$	$ 9,579

Note 14. Subsequent Events

Subsequent to December 31, 2008, oil and gas commodity prices have continued to decline. In the event that commodity prices continue to deteriorate throughout the first quarter of 2009, the Company may be required to record a ceiling test impairment, and such impairment could be material to its financial position and results of operations.

Note 15. Oil and Gas Producing Activities and Capitalized Costs (Unaudited)

The results of operations from the Company s oil and gas producing activities below exclude non-oil and gas revenues, general and administrative expenses, interest income and interest expense. Income tax expense was determined by applying the statutory rates to pretax operating results.

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2008, 2007 and 2006

	Year Ended December 31, 2008	2007	2006
	(In thousands)		
Oil and gas sales	$ 1,247,963	$ 873,134	$ 656,218
Lease operating costs	(231,644)	(152,627)	(91,592)
Severance and ad valorem taxes	(18,191)	(13,101)	(9,070)
Transportation	(14,996)	(8,794)	(5,077)
Depreciation, depletion and amortization	(463,989)	(383,154)	(293,370)
Full Cost Ceiling Test Impairment	(575,607)		
Income tax benefit (expense)	20,214	(110,095)	(91,788)
Results of operations	$ (36,250)	$ 205,363	$ 165,321

The following table summarizes the Company s capitalized costs of oil and gas properties.

	At December 31, 2008	2007	2006
	(In thousands)		
Unevaluated properties, not subject to amortization	$ 201,121	$ 40,455	$ 40,246
Properties subject to amortization	4,448,146	3,118,273	2,345,041
Capitalized costs	4,649,267	3,158,728	2,385,287
Accumulated depreciation, depletion and amortization	(1,767,027)	(751,126)	(384,948)
Net capitalized costs	$ 2,882,240	$ 2,407,602	$ 2,000,339

Costs incurred in property acquisition, exploration and development activities were as:

	Year Ended December 31, 2008	2007	2006
	(In thousands, except DD&A rate)		
Property acquisition costs:			
Unproved properties	$ 173,531	$ 48,891	$ 47,655
Unproved properties Forest Merger			116,699
Proved properties MGOM Acquisition	228,799		

Proved properties	Spraberry	42,541	122,895	
Proved properties	Atwater Valley Block 426 (Bass Lite)	30,159		
Proved properties	Forest Merger			929,451
Proved properties	West Cameron 110/111			70,928
Proved properties	Other	1,130		
Exploration costs		231,433	146,450	141,910
Development costs		533,918	398,130	294,058
Asset retirement obligation(1)		259,402	61,861	199,301
Capitalized internal costs(2)		29,465	14,428	12,525
Total costs incurred(3)		$ 1,530,378	$ 792,655	$ 1,812,527

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MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2008, 2007 and 2006

(1) Includes asset retirement cost in conjunction with the MGOM acquisition for the year ended December 31, 2008 of approximately $44.4 million and the Forest Merger for the year ended December 31, 2006 of approximately $165.2 million.

(2) Costs included capitalized general and administrative expense of $19.8 million, $14.0 million and $11.0 million in 2008, 2007 and 2006, respectively and capitalized interest expense of $9.7 million, $0.5 million and $1.5 million in 2008, 2007 and 2006, respectively.

(3) Total costs are inclusive of non cash items such as capital expenditures and asset retirement obligation accruals.

The Company capitalizes interest and internal costs associated with exploration and production activities in progress. The capitalized internal costs were approximately 46%, 25%, and 20% of the Company s gross general and administrative expenses, excluding share-based compensation expense for the years ended December 31, 2008, 2007 and 2006, respectively.

The following table summarizes costs related to unevaluated properties that have been excluded from amounts subject to amortization at December 31, 2008. There are no individually significant properties or significant development projects included in our unevaluated property balance. The Company regularly evaluates these costs to determine whether impairment has occurred. The majority of these costs are expected to be evaluated and included in the amortization base within three years.

	Period Incurred Year Ended December 31,				Total at December 31,
	2008	2007	2006	Prior	2008
			(In thousands)		
Unproved leasehold acquisition and geological and geophysical costs	$ 128,908	$ 15,618	$ 11,988	$ 11,387	$ 167,901
Unevaluated exploration and development costs	22,880	990	2	146	24,018
Capitalized interest	8,878	132	19	173	9,202
Total	$ 160,666	$ 16,740	$ 12,009	$ 11,706	$ 201,121

All of the excluded costs at December 31, 2008 relate to activities in the Gulf of Mexico.

Note 16. Supplemental Oil and Gas Reserve and Standardized Measure Information (Unaudited)

Estimated proved net recoverable reserves as shown below include only those quantities that are expected to be commercially recoverable at prices and costs in effect at the balance sheet dates under existing regulatory practices and with conventional equipment and operating methods. Proved developed reserves represent only those reserves expected to be recovered through existing wells. Proved undeveloped reserves include those reserves expected to be recovered from new wells on undrilled acreage or from existing wells on which a relatively major expenditure is required for recompletion. Also included in the Company s proved undeveloped reserves as of December 31, 2008 were reserves expected to be recovered from wells for which certain drilling and completion operations had occurred as of that date, but for which significant future capital expenditures were required to bring the wells into commercial production.

Reserve estimates are inherently imprecise and may change as additional information becomes available. Furthermore, estimates of oil and gas reserves, of necessity, are projections based on engineering data, and there are uncertainties inherent in the interpretation of such data as well as in the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Accordingly, estimates of the economically recoverable quantities of oil and

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2008, 2007 and 2006

natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of the future net cash flows expected there from as prepared by different engineers or by the same engineers at different times may vary substantially. There also can be no assurance that the reserves set forth herein will ultimately be produced or that the proved undeveloped reserves set forth herein will be developed within the periods anticipated. It is likely that variances from the estimates will be material. In addition, the estimates of future net revenues from estimated proved reserves of the Company and the present value thereof are based upon certain assumptions about future production levels, prices and costs that may not be correct when judged against actual subsequent experience. The Company emphasizes with respect to the estimates prepared by independent petroleum engineers that the discounted future net cash flows should not be construed as representative of the fair market value of the estimated proved reserves owned by the Company since discounted future net cash flows are based upon projected cash flows, which do not provide for changes in oil and natural gas prices from those in effect on the date indicated or for escalation of expenses and capital costs subsequent to such date. The meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based. Actual results will differ, and are likely to differ materially, from the results estimated.

ESTIMATED QUANTITIES OF PROVED RESERVES

	Oil & NGLs (Mbbl)	Natural Gas (MMcf)	Natural Gas Equivalent (MMcfe)
December 31, 2005	21,647	207,686	337,568
Revisions of previous estimates	8,685	(58,055)	(5,947)
Extensions, discoveries and other additions	9,823	93,112	152,050
Purchases of reserves in place	12,410	244,741	319,201
Sales of reserves in place	(354)	(4,733)	(6,857)
Production	(4,075)	(56,064)	(80,512)
December 31, 2006	48,136	426,687	715,503
Revisions of previous estimates	5,690	2,506	36,643
Extensions, discoveries and other additions	4,671	61,548	89,576
Purchases of reserves in place	11,763	25,832	96,407
Sales of reserves in place	(283)	(341)	(2,041)
Production	(5,414)	(67,793)	(100,273)
December 31, 2007	64,563	448,439	835,815
Revisions of previous estimates	(2,404)	(29,839)	(44,264)
Extensions, discoveries and other additions	9,525	137,792	194,855
Purchases of reserves in place	4,102	81,500	106,112

Sales of reserves in place	(40)	(18)	(258)
Production	(6,439)	(79,756)	(118,389)
December 31, 2008	69,304	558,048	973,871

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MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2008, 2007 and 2006

ESTIMATED QUANTITIES OF PROVED DEVELOPED RESERVES

	Oil & NGLs (Mbbl)	Natural Gas (MMcf)	Natural Gas Equivalent (MMcfe)
December 31, 2005	9,564	110,011	167,395
December 31, 2006	26,807	247,821	408,663
December 31, 2007	39,634	326,069	563,874
December 31, 2008	42,802	420,866	677,679

The following is a summary of a Standardized Measure of discounted net future cash flows related to the Company s proved oil and gas reserves. The information presented is based on a calculation of estimated proved reserves using discounted cash flows based on year-end prices, costs and economic conditions and a 10% discount rate. The additions to estimated proved reserves from new discoveries and extensions could vary significantly from year to year. Additionally, the impact of changes to reflect current prices and costs of reserves proved in prior years could also be significant. Accordingly, the information presented below should not be viewed as an estimate of the fair value of the Company s oil and gas properties, nor should it be considered indicative of any trends.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

	Year Ended December 31,		
	2008	2007	2006
		(In thousands)	
Future cash inflows	$ 5,609,181	$ 8,330,819	$ 4,858,420
Future production costs	(1,823,535)	(1,970,944)	(1,278,228)
Future development costs	(1,167,113)	(955,278)	(1,016,519)
Future income taxes	(375,593)	(1,467,999)	(528,135)
Future net cash flows	2,242,940	3,936,598	2,035,538
Discount of future net cash flows at 10% per annum	(759,933)	(1,704,689)	(795,677)
Standardized measure of discounted future net cash flows	$ 1,483,007	$ 2,231,909	$ 1,239,861

During recent years, there have been significant fluctuations in the prices paid for crude oil in the world markets and in the United States, including the posted prices paid by purchasers of the Company s crude oil. The Henry Hub cash prices of oil and gas at December 31, 2008, 2007 and 2006, used in the above table, were $44.61, $96.01 and $61.06 per Bbl, respectively, and $5.71, $6.79 and $5.62 per MMBtu, respectively, and do not include the effect of hedging contracts in place at period end.

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MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2008, 2007 and 2006

The following are the principal sources of change in the Standardized Measure of discounted future net cash flows (in thousands):

	Year Ended December 31,		
	2008	2007	2006
		(In thousands)	
Standardized Measure January 1,	$ 2,231,909	$ 1,239,861	$ 906,565
Sales and transfers of oil and gas produced, net of production costs	(983,131)	(698,652)	(553,766)
Net changes in prices and production costs	(1,203,277)	470,932	(434,364)
Extensions and discoveries, net of future development and production costs	245,718	202,272	311,077
Purchases of reserves in place	157,125	353,441	568,576
Development costs during period and net change in development costs	(89,099)	812,655	245,050
Revision of previous quantity estimates	(74,844)	175,039	101,331
Sales of reserves in place	(1,956)	(1,383)	(10,642)
Net change in income taxes	647,837	(510,611)	53,549
Accretion of discount before income taxes	306,421	123,986	90,656
Changes in production rates (timing) and other	246,083	64,369	(38,171)
Standardized Measure December 31,	$ 1,483,007	$ 2,231,909	$ 1,239,861

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Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosures.***

None

Item 9A. ***Controls and Procedures.***

Evaluation of Disclosure Controls and Procedures

Mariner maintains disclosure controls and procedures that are designed to ensure that information required to be disclosed in its filings with the Securities and Exchange Commission (SEC) are recorded, processed, summarized and reported within the time period specified in the SEC s rules and forms, and that such information is accumulated and communicated to management, including its chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosures based on the definition of disclosure controls and procedures as defined in Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act). In designing and evaluating the disclosure controls and procedures, management has recognized that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance, not absolute assurance, of achieving the desired control objectives, and management is required to apply judgment in evaluating its controls and procedures. As of the end of the period covered by this report, and under the supervision and with the participation of management, including the Company s Chief Executive Officer and Chief Financial Officer, the Company evaluated the effectiveness of the design and operation of these disclosure controls and procedures. Based on this evaluation, the Company s Chief Executive Officer and Chief Financial Officer have concluded that the Company s disclosure controls and procedures were effective as of the end of the period covered by this annual report.

Management s Report on Internal Control over Financial Reporting

Management s report on internal control over financial reporting as of December 31, 2008 is in Item 8. Financial Statements and Supplementary Data in Part II of this Annual Report on Form 10-K.

Changes in Internal Controls over Financial Reporting.

There were no changes that occurred during the fourth quarter of the fiscal year covered by this Annual Report on Form 10-K that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information.***

Not applicable.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance.***

The information required by this item is incorporated by reference to our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K, and with respect to information regarding our executive officers, to Item 4. Submission of Matters to a Vote of Security Holders Executive Officers of the Registrant in this Form 10-K.

Item 11. ***Executive Compensation.***

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*.**

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

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Item 13. ***Certain Relationships and Related Transactions, and Director Independence.***

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

Item 14. ***Principal Accounting Fees and Services.***

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules.***

(a)(1) *Financial Statements:*

The financial statements included in Item 8 above are filed as part of this Form 10-K.

(a)(2), (c) *Financial Statement Schedules:*

None.

(a)(3) and (b) *Exhibits:*

The exhibits listed on the Index to Exhibits which follows the Signatures hereto are filed as part of this Form 10-K.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Mariner Energy, Inc. has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 6, 2009.

Mariner Energy, Inc.

By: /s/ Scott D. Josey

Scott D. Josey,
Chairman of the Board, Chief Executive
Officer and President

INDEX TO EXHIBITS

Number	Description
2.1 *	Agreement and Plan of Merger dated as of September 9, 2005 among Forest Oil Corporation, SML Wellhead Corporation, Mariner Energy, Inc. and MEI Sub, Inc. (incorporated by reference to Exhibit 2.1 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
2.2 *	Letter Agreement dated as of February 3, 2006 among Forest Oil Corporation, Forest Energy Resources, Inc., Mariner Energy, Inc. and MEI Sub, Inc. amending the transaction agreements (incorporated by reference to Exhibit 2.2 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
2.3 *	Letter Agreement, dated as of February 28, 2006, among Forest Oil Corporation, Forest Energy Resources, Inc., Mariner Energy, Inc. and MEI Sub, Inc. amended the transaction agreements (incorporated by reference to Exhibit 2.1 to Mariner s Form 8-K filed on March 3, 2006).
2.4 *	Letter Agreement, dated April 12, 2006, among Forest Oil Corporation, Mariner Energy Resources, Inc. and Mariner Energy, Inc. amended the transaction agreements (incorporated by reference to Exhibit 2.1 to Mariner s Form 8-K filed on April 13, 2006).
2.5 *	Membership Interest Purchase Agreement by and between Hydro Gulf of Mexico, Inc. and Mariner Energy, Inc., executed December 23, 2007 (incorporated by reference to Exhibit 2.1 to Mariner s Form 8-K filed on February 5, 2008).
3.1 *	Second Amended and Restated Certificate of Incorporation of Mariner Energy, Inc., as amended (incorporated by reference to Exhibit 3.1 to Mariner s Registration Statement on Form S-8 (File No. 333-132800) filed on March 29, 2006).
3.2 *	Certificate of Designations of Series A Junior Participating Preferred Stock of Mariner Energy, Inc. (incorporated by reference to Exhibit 3.1 to Mariner s Form 8-K filed on October 14, 2008).
3.3 *	Fourth Amended and Restated Bylaws of Mariner Energy, Inc. (incorporated by reference to Exhibit 3.2 to Mariner s Registration Statement on Form S-4 (File No. 333-129096) filed on October 18, 2005).
4.1 *	Indenture, dated as of April 30, 2007, among Mariner Energy, Inc., the guarantors party thereto and Wells Fargo Bank, N.A., as trustee (incorporated by reference to Exhibit 4.1 to Mariner s Form 8-K filed on May 1, 2007).
4.2 *	Indenture, dated as of April 24, 2006, among Mariner Energy, Inc., the guarantors party thereto and Wells Fargo Bank, N.A., as trustee (incorporated by reference to Exhibit 4.1 to Mariner s Form 8-K filed on April 25, 2006).
4.3 *	Exchange and Registration Rights Agreement, dated as of April 24, 2006, among Mariner Energy, Inc., the guarantors party thereto and the initial purchasers party thereto (incorporated by reference to Exhibit 4.2 to Mariner s Form 8-K filed on April 25, 2006).
4.4 *	Rights Agreement, dated as of October 12, 2008, between Mariner Energy, Inc. and Continental Stock Transfer & Trust Company, as Rights Agent (incorporated by reference to Exhibit 4.1 to Mariner s Form 8-K filed on October 14, 2008).
4.5 *	Amended and Restated Credit Agreement, dated as of March 2, 2006, among Mariner Energy, Inc. and Mariner Energy Resources, Inc., as Borrowers, the Lenders party thereto from time to time, as Lenders, and Union Bank of California, N.A., as Administrative Agent and as Issuing Lender (incorporated by reference to Exhibit 4.1 to Mariner s Form 8-K filed on March 3, 2006).
4.6 *	Amendment No. 1 and Consent, dated as of April 7, 2006, among Mariner Energy, Inc. and Mariner Energy Resources, Inc., as Borrowers, the Lenders party thereto, and Union Bank of California, N.A., as Administrative Agent for such Lenders and as Issuing Lender for such Lenders (incorporated by reference to Exhibit 4.1 to Mariner s Form 8-K filed on April 13, 2006).

4.7 *	Amendment No. 2, dated as of October 13, 2006, among Mariner Energy, Inc. and Mariner Energy Resources, Inc., as Borrowers, the Lenders party thereto, and Union Bank of California, N.A., as Administrative Agent for such Lenders and as Issuing Lender for such Lenders (incorporated by reference to Exhibit 4.1 to Mariner s Form 8-K filed on October 18, 2006).
4.8 *	Amendment No. 3 and Consent, dated as of April 23, 2007, among Mariner Energy, Inc. and Mariner Energy Resources, Inc., as Borrowers, the Lenders party thereto, and Union Bank of California, N.A., as Administrative Agent for such Lenders and as Issuing Lender for such Lenders (incorporated by reference to Exhibit 4.1 to Mariner s Form 8-K filed on April 24, 2007).

Number		Description
4.9	*	Amendment No. 4, dated as of August 24, 2007, among Mariner Energy, Inc. and Mariner Energy Resources, Inc., as Borrowers, the Lenders party thereto, and Union Bank of California, N.A., as Administrative Agent for such Lenders and as Issuing Lender for such Lenders (incorporated by reference to Exhibit 4.1 to Mariner s Form 8-K filed on August 27, 2007).
4.10	*	Amendment No. 5 and Agreement, dated as of January 31, 2008, among Mariner Energy, Inc. and Mariner Energy Resources, Inc., as Borrowers, the Lenders party thereto, and Union Bank of California, N.A., as Administrative Agent for such Lenders and as Issuing Lender for such Lenders (incorporated by reference to Exhibit 4.1 to Mariner s Form 8-K filed on February 5, 2008).
4.11	*	Master Assignment, Agreement and Amendment No. 6, dated as of June 2, 2008, among Mariner Energy, Inc. and Mariner Energy Resources, Inc., as Borrowers, the Lenders party thereto, and Union Bank of California, N.A., as Administrative Agent for such Lenders and as Issuing Lender for such Lenders (incorporated by reference to Exhibit 4.1 to Mariner s Form 8-K filed on June 3, 2008).
4.12	*	Amendment No. 7, dated as of December 12, 2008, among Mariner Energy, Inc. and Mariner Energy Resources, Inc., as Borrowers, the Lenders party thereto, and Union Bank of California, N.A., as Administrative Agent for such Lenders and as Issuing Lender for such Lenders (incorporated by reference to Exhibit 4.1 to Mariner s Form 8-K filed on December 15, 2008).
10.1	*	Underwriting Agreement, dated April 25, 2007, among J.P. Morgan Securities Inc., as Representative of the several Underwriters listed in Schedule 1 thereto, Mariner Energy, Inc., Mariner Energy Resources, Inc., Mariner LP LLC, and Mariner Energy Texas LP (incorporated by reference to Exhibit 1.1 to Mariner s Form 8-K filed on April 26, 2007).
10.2	*	Purchase Agreement, dated as of April 19, 2006, among Mariner Energy, Inc., Mariner LP LLC, Mariner Energy Resources, Inc., Mariner Energy Texas LP and the initial purchasers party thereto (incorporated by reference to Exhibit 10.1 to Mariner s Form 8-K filed on April 25, 2006).
10.3	*	Form of Indemnification Agreement between Mariner Energy, Inc. and each of its directors and officers (incorporated by reference to Exhibit 10.2 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.4	*	Mariner Energy, Inc. Second Amended and Restated Stock Incentive Plan, effective as of February 6, 2007 (incorporated by reference to Exhibit 10.3 to Mariner s Form 10-K filed on April 2, 2007).
10.5	*	Form of Non-Qualified Stock Option Agreement, Mariner Energy, Inc. Amended and Restated Stock Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.5 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.6	*+	Form of Non-Qualified Stock Option Agreement, Mariner Energy, Inc. Amended and Restated Stock Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.6 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.7	*+	Form of Restricted Stock Agreement (directors) under Mariner Energy, Inc. Second Amended and Restated Stock Incentive Plan (incorporated by reference to Exhibit 10.6 to Mariner s Form 10-K filed on April 2, 2007).
10.8	*+	Form of Restricted Stock Agreement (employee with employment agreement) under Mariner Energy, Inc. Second Amended and Restated Stock Incentive Plan (incorporated by reference to Exhibit 10.7 to Mariner s Form 10-K filed on April 2, 2007).
10.9	*	Form of Restricted Stock Agreement (employee without employment agreement) under Mariner Energy, Inc. Second Amended and Restated Stock Incentive Plan (incorporated by reference to Exhibit 10.8 to Mariner s Form 10-K filed on April 2, 2007).
10.10	*+	Form of Restricted Stock Agreement for grants made after August 24, 2008 as part of 2008 Long-Term Performance-Based Restricted Stock Program under Mariner Energy, Inc. Second

Amended and Restated Stock Incentive Plan (incorporated by reference to Exhibit 10.3 to Mariner s Form 10-Q filed on November 7, 2008).

Number	Description
10.11 *+	Form of Restricted Stock Agreement for grants made before August 25, 2008 as part of 2008 Long-Term Performance-Based Restricted Stock Program under Mariner Energy, Inc. Second Amended and Restated Stock Incentive Plan (incorporated by reference to Exhibit 10.2 to Mariner s Form 8-K filed on June 19, 2008).
10.12 *+	Amendment, dated as of August 25, 2008, to outstanding Restricted Stock Agreements covering grants made before August 25, 2008 as part of 2008 Long-Term Performance-Based Restricted Stock Program under Mariner Energy, Inc. Second Amended and Restated Stock Incentive Plan (incorporated by reference to Exhibit 10.5 to Mariner s Form 10-Q filed on November 7, 2008).
10.13 *	Form of Nonstatutory Stock Option Agreement for certain employees of Mariner Energy, Inc. or Mariner Energy Resources, Inc. who formerly held unvested options issued by Forest Oil Corporation (incorporated by reference to Exhibit 10.14 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.14 *	Mariner Energy, Inc. Equity Participation Plan, effective March 11, 2005 (incorporated by reference to Exhibit 10.10 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.15 *	First Amendment to Mariner Energy, Inc. Equity Participation Plan, effective as of March 16, 2006 (incorporated by reference to Exhibit 10.11 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.16 *+	Form of Restricted Stock Agreement, Mariner Energy, Inc. Equity Participation Plan for employees with employment agreements (incorporated by reference to Exhibit 10.12 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.17 *	Form of Restricted Stock Agreement, Mariner Energy, Inc. Equity Participation Plan for employees without employment agreements (incorporated by reference to Exhibit 10.13 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.18 *+	Compensation of Non-Employee Directors of Mariner Energy, Inc. (incorporated by reference to Exhibit 10.3 to Mariner s Form 10-Q filed on November 14, 2007).
10.19 *+	Employment Agreement by and between Mariner Energy, Inc. and Scott D. Josey, dated February 7, 2005 (incorporated by reference to Exhibit 10.15 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.20 *+	Employment Agreement by and between Mariner Energy, Inc. and Dalton F. Polasek, dated February 7, 2005 (incorporated by reference to Exhibit 10.16 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.21 *+	Employment Agreement, by and between Mariner Energy, Inc. and John H. Karnes, dated as of October 16, 2006 (incorporated by reference to Exhibit 10.1 to Mariner s current report on Form 8-K filed on October 18, 2006).
10.22 *+	Employment Agreement by and between Mariner Energy, Inc. and Michiel C. van den Bold, dated February 7, 2005 (incorporated by reference to Exhibit 10.17 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.23 *+	Amendment to Employment Agreement by and between Mariner Energy, Inc. and Michiel C. van den Bold, dated as of June 8, 2006 (incorporated by reference to Exhibit 10.18 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.24 *+	Second Amended and Restated Employment Agreement by and between Mariner Energy, Inc., Mariner Energy Resources, Inc. and Judd Hansen, dated June 8, 2006 (incorporated by reference to Exhibit 10.19 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.25 *	

		Registration Rights Agreement among Mariner Energy, Inc. and each of the investors identified therein, dated March 11, 2005 (incorporated by reference to Exhibit 10.24 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
12	*	Statement regarding Computation of Ratio of Earnings to Fixed Charges (incorporated by reference to Exhibit 12 to Mariner s annual report Form 10-K filed on March 2, 2009).
21	*	List of subsidiaries of Mariner Energy, Inc. (incorporated by reference to Exhibit 21 to Mariner s annual report Form 10-K filed on March 2, 2009).
23.1	*	Consent of Deloitte & Touche LLP (incorporated by reference to Exhibit 23.1 to Mariner s annual report Form 10-K filed on March 2, 2009).

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Number	Description
23.2 *	Consent of Ryder Scott Company, L.P. (incorporated by reference to Exhibit 23.2 to Mariner s annual report Form 10-K filed on March 2, 2009).
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Incorporated by reference as indicated.

\+ Management contract, plan or arrangement.

In accordance with SEC Release 33-8238, Exhibits 32.1 and 32.2 are being furnished and not filed.