MARINER ENERGY INC
Form 10-K
March 01, 2010

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

Form 10-K

þ	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the fiscal year ended December 31, 2009**
	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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No o

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or 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, 2009 was approximately $1,150,891,162 based on the closing sale price of $11.75 per share as reported by the New York Stock Exchange on June 30, 2009. The number of shares of common stock of the registrant issued and outstanding on

February 22, 2010 was 101,780,353.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of registrant s Proxy Statement relating to the Annual Meeting of Stockholders to be held May 5, 2010 are incorporated by reference into Part III of this Form 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;

risks related to significant acquisitions or other strategic transactions, such as failure to realize expected benefits or objectives for future operations; and

foreign currency risks.

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 four principal 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 Coast, where, in December 2009, we acquired interests predominantly in the Vicksburg, Queen City and Deep Frio producing trends in South Texas. As is the case with our Permian Basin operation, we expect the relatively lower risk and cost of exploiting our Gulf Coast properties to further counterbalance those of our Gulf of Mexico deepwater operations.

Gulf of Mexico Deepwater, where we have actively conducted exploration and development projects since 1996 in water depths ranging from approximately 1,300 feet up to 7,100 feet. Employing our experienced geoscientists, rich seismic database, and extensive subsea tieback expertise, we have participated in more than 79 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 exploration and exploitation 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 onshore operations, as well as for expansion into new operating areas.

We also are investigating a variety of shale and unconventional resource opportunities in the United States and Canada, such as green field leasing, joint ventures and acquisitions. In 2009, we added a team of approximately 10 geoscientists experienced in unconventional resource plays in those areas. We also formed a Canadian subsidiary which opened an office in Calgary. We initially are targeting liquids-rich plays with relatively low entry costs in the Rocky Mountains, South Texas and the Permian Basin, including unconventional potential of our existing asset base. During 2009, we acquired working interests in approximately 80,000 (43,000 net) acres in unconventional plays in North Dakota, Wyoming, Arkansas and New Mexico. Our secured revolving credit facility currently limits our investment in our Canadian operation to $25.0 million.

During 2009, we produced approximately 126.5 Bcfe and our average daily production rate was 347 MMcfe. At December 31, 2009, we had 1.087 Tcfe of estimated proved reserves, of which approximately 56% were onshore (47% in the Permian Basin and 8% in the Gulf Coast), with the balance offshore (15% in the Gulf of Mexico deepwater and 29% on the Gulf of Mexico shelf); 53% were natural gas; and 47% were oil and natural gas liquids (NGLs). Approximately 66% 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

Onshore Acquisition On December 31, 2009, we acquired the reorganized subsidiaries and operations of Edge Petroleum Corporation (Edge). The material assets acquired consist primarily of (i) proved reserves estimated by Ryder Scott Company, L.P. as of December 31, 2009 of 100.5 Bcfe, of which approximately 75% are developed (consisting of 69% natural gas and 31% oil and NGLs), 81% are located in South Texas, and 44% are in the Flores/Bloomberg field in Starr County, Texas, (ii) approximately 60,000 net acres of undeveloped leasehold, primarily in Texas and New Mexico, and (iii) deferred tax assets of approximately $83.3 million, comprised of approximately $61.2 million in net operating loss carryforwards and $22.1 million in built-in losses from carryover tax basis in the properties. The effective date of the acquisition was June 30, 2009 and the purchase price was $260.0 million, less adjustments which resulted in a net purchase price as of December 31, 2009 of approximately $213.6 million, subject to final adjustments. We financed the net purchase price by borrowing under our secured revolving credit facility.

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 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, making a number of significant deepwater discoveries in the Gulf of Mexico in the last five years. In addition, we believe our reputation for generating high-quality exploration prospects creates potentially valuable partnering opportunities, which enables us to participate in exploration projects developed by other operators.

Development: Our development and exploitation efforts are intended to complement our higher-risk, high-impact exploration projects through a variety of moderate-risk activities targeted at maximizing recovery and production from known reservoirs. These activities are also aimed at finding overlooked oil and gas accumulations in and around existing fields and are designed to establish critical operating mass from which to expand in our focus areas. Our geoscientists and engineers have a excellent 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.

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. 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 primarily among the Permian Basin, Gulf Coast 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 of Mexico, 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 onshore, 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. We also are an active participant at MMS lease sales. Furthermore, we have a large and growing asset base onshore that we anticipate is capable of sustaining our current drilling program for a number of years. We believe that our large acreage position makes us less dependent on acquisitions for our growth as compared to companies that have less extensive drilling inventories.

Exploration expertise. Our seasoned team of geoscientists has made significant discoveries in the Gulf of Mexico, achieving a cumulative 62% success rate during the three years ended December 31, 2009. Our geoscientists collectively 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. As of December 31, 2009, we served as operator of properties representing approximately 86% of our production and had an average 73% 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 infrastructure through subsea flow lines and umbilicals. 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, Gulf Coast, 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 %	2009 Net Production(2) (Bcfe)	Net Estimated Proved Reserves (Bcfe)	Estimated Proved Reserves % Oil /% Gas(1)
Permian Basin:					
Spraberry (Aldwell Unit)	Mariner	75%	8.0	245.8	66%/34%
Spraberry (Tamarack)	Mariner	93%	4.7	142.3	77%/23%
Spraberry (Texas Scottish Rite Hospital)	Mariner	100%	1.1	43.5	74%/26%
Deadwood	Mariner	73%	0.5	21.9	77%/23%
Spraberry (North Stiles Unit)	Mariner	50%	1.7	14.0	70%/30%
Gulf Coast:					
Flores	Mariner	41%		43.9	31%/69%
Chapman Ranch	Mariner	90%		11.2	30%/70%
Muy Grande	Mariner	100%		7.4	0%/100%
Duson	BTA	44%		6.1	22%/78%
Midway Dome	Mariner	89%		4.4	16%/84%
Gulf of Mexico Deepwater:					
Atwater Valley 426 (Bass Lite)	Mariner	54%	18.4	77.0	0%/100%
Garden Banks 462 (Geauxpher)	Mariner	60%	13.0	24.1	10%/90%
Green Canyon 646 (Daniel Boone)	W&T Offshore	40%	1.1	19.1	69%/31%
East Breaks 597	Mariner	50%		9.9	61%/39%
Ewing Bank 921 (North Black Widow)	ENI	35%	1.8	8.5	93%/7%
Gulf of Mexico Shelf:					
Brazos A19	Mariner	100%		38.8	0%/100%

Vermilion 380	Mariner	100%	1.1	33.2	47%/53%
West Cameron 110	Mariner	100%	3.0	24.6	2%/98%
South Pass 24	Mariner	97%	1.5	21.2	59%/41%
South Timbalier 49	Mariner	100%		18.2	59%/41%

(1) NGLs are included in Oil

(2) No production results are included for properties of the Edge subsidiaries we acquired on December 31, 2009.

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Permian Basin Operations

Our Permian Basin operations historically have emphasized downspacing redevelopment activities in the prolific oil-producing Spraberry field. Since we began our Permian Basin redevelopment initiative in 2002, we have increased by approximately seven-fold our net acreage position and plan 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 2009, our Permian Basin operations produced approximately 18.3 Bcfe (14% of our total production) and accounted for approximately 515.0 Bcfe or 47% of our total estimated proved reserves at year end. Oil and NGLs accounted for 71% of total Permian Basin production for 2009. We drilled 51 wells in the region during 2009, 92% of which were productive. 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 Aldwell Unit. We operate our wells in this field and hold an average 75% working interest. At year-end 2009, our share of estimated proved reserves attributed to this field was 245.8 Bcfe, consisting of 66% oil and NGLs and 34% natural gas. Net production for 2009 was 8.0 Bcfe.

The Spraberry Tamarack and Spraberry Texas Scottish Rite Hospital are the next largest fields with 142.3 and 43.5 Bcfe of estimated proved reserves, respectively. The Deadwood field follows with 21.9 Bcfe of estimated proved reserves and the Spraberry North Stiles Unit has estimated proved reserves of 14.0 Bcfe.

Gulf Coast Operations

On December 31, 2009, we acquired interests in 244.0 gross and 98.3 net acres in South Texas, predominantly in the Vicksburg, Queen City and Deep Frio producing trends. As of December 31, 2009, we operated approximately 275 gross wells in this region and had 151 gross non-operated wells.

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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, 2009, we held interests in 99 deepwater blocks and 38 subsea wells. These wells were tied back to 17 host production facilities for production processing. As of December 31, 2009, an additional six projects (Dalmatian, Wide Berth, Balboa, Heidelberg, Lucius and Bushwood) were under development for either tieback to three additional host production facilities or in the case of Heidelberg and Lucius, production from dedicated facilities if warranted by the amount of estimated reserves. 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 2009, our deepwater operations produced approximately 52.8 Bcfe (42% of our total production) and accounted for approximately 161.7 Bcfe or 15% of our total estimated proved reserves at year end. Natural gas accounted for 80% of total deepwater production for 2009. We drilled six wells in the region during 2009, four of which were productive.

We operate Atwater Valley 426, known as Bass Lite, in which we hold a 54% working interest. It is in the Pleistocene formation and is located in approximately 6,600 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. Limited production on Bass Lite began in February 2008 due to a temporary early production system. The project commenced production at full capacity once the topside facilities work was completed in August 2008 and the field produced 18.4 Bcfe net to our interest during 2009. At year end 2009, our share of estimated proved reserves attributed to this field was 77.0 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 2,800 feet, was drilled to a total depth of 23,156 feet (measured depth). Production on Geauxpher began in May 2009 and the field produced 13.0 Bcfe net to our interest during 2009. At year-end 2009, our share of estimated proved reserves attributed to the discovery was 24.1 Bcfe, consisting of 10% oil and NGLs and 90% natural gas.

Green Canyon 646, known as Daniel Boone, is operated by W&T Offshore, Inc. and consists of one well in the Pliocene/Pleistocene formation. It is located in approximately 4,200 feet of water and we have an approximate 40% working interest in the well. Production on Daniel Boone began in October 2009 and the field produced 1.1 Bcfe net to our interest during 2009. At year-end 2009, our share of estimated proved reserves attributed to this field was 19.1 Bcfe, consisting of 69% oil and 31% natural gas.

We operate East Breaks 597, known as Balboa, in which we hold a 50% working interest. The well lies in water depths of approximately 3,350 feet and was drilled in July 2001. The well was completed in September 2009 and is awaiting tieback to the Boomvang Spar. Production from Balboa is expected in the second half of 2010. Our share of estimated proved reserves at year-end 2009 was 9.9 Bcfe consisting of approximately 61% oil and 39% 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 2009 was approximately 1.8 Bcfe. At year-end 2009, our share of estimated proved reserves attributed to the field was 8.5 Bcfe, consisting of 93% oil and 7% 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. 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 2009, our Gulf of Mexico shelf operation produced approximately 55.4 Bcfe (44% of our total production) and accounted for approximately 315.1 Bcfe or 29% of our total estimated proved reserves at year end. Natural gas accounted for 79% of total shelf production for 2009. We drilled ten wells in the region during 2009, six of which were productive.

Our largest field in the Gulf of Mexico shelf by reserves is Brazos A19. At year-end 2009, estimated proved reserves, all of which are undeveloped, attributed to this field were 38.8 Bcfe, of which 100% is natural gas. This is a recently acquired block and plans are being made to exploit these reserves.

At year-end 2009 estimated proved reserves attributed to our Vermillion 380 field were 33.2 Bcfe, consisting of approximately 47% oil and NGLs and 53% natural gas. During 2008 and 2009, we drilled five wells and added additional production capacity on the A platform. Hurricane Ike damaged the structure with the rig on the platform, causing us to suspend drilling while underwater structural repairs were made. We brought the platform back on production at reduced rates until the facilities upgrade was finished. The platform is currently producing approximately 28 MMcfe per day. Our working interest in this block is 100%. Production at Vermillion 380 was approximately 1.1 Bcfe in 2009.

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 3.0 Bcfe net in 2009. At year-end 2009, estimated proved reserves attributed to this field were 24.6 Bcfe, consisting of approximately 2% oil and NGLs and 98% natural gas.

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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 2009 produced approximately 1.5 Bcfe net. At year-end 2009, estimated proved reserves attributed to this field were 21.2 Bcfe, consisting of approximately 59% oil and NGLs and 41% natural gas.

We operate South Timbalier 49, in which we hold a 100% working interest. We initiated full production from this field in September 2009. We are producing from the first of many reservoirs encountered in the A-1 well and are currently producing approximately 8 MMcfe per day. At year-end 2009, estimated proved reserves attributed to this field were 18.2 Bcfe (approximately 59% oil and 41% natural gas).

Estimated Proved Reserves

The following tables present certain information with respect to our estimated proved oil and natural gas reserves. The reserve information in the tables below is based on estimates made in fully-engineered reserve reports prepared by Ryder Scott Company, L.P. (except the amount of standardized measure of discounted future net cash flows and information in the table for Sensitivity of Reserves to Prices). Reserve volumes and values were determined under the method prescribed by the SEC, which requires the application of the 12-month average price for natural gas and oil calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month prior period to the end of the reporting period 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. The proved reserve estimates represent our net revenue interest in our properties.

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Summary of Oil and Gas Reserves as of December 31, 2009
Based on Average 2009 Prices

Reserves Category:	Natural gas (Bcf)	Oil (MMBbls)	NGLs (MMBbls)	Total (Bcfe)
Proved Developed	406.8	31.5	20.1	716.4
Proved Undeveloped	164.6	21.0	13.4	370.7
Total estimated proved oil and gas reserves	571.4	52.5	33.5	1,087.1

PV10 value(1) ($ in millions):	
Proved developed reserves	$ 1,350.0
Proved undeveloped reserves	152.2
Total PV10 value(1)	$ 1,502.2
Standardized measure of discounted future net cash flows	$ 1,468.4
Twelve-month average prices used in calculating proved reserve measures (excluding effects of hedging):	
Natural gas ($/MMBtu)	$ 3.87
Oil ($/Bbl)	$ 61.18

Sensitivity of Reserves to Prices

By Principal Product Type and Price Scenario

	Natural Gas (Bcf)	Oil (MMBbls)	NGLs (MMBbls)
Proved oil and natural gas reserves:			
10% Increase in Price	576.9	53.0	33.9
10% Decrease in Price	565.7	51.8	32.9

The following table sets forth certain information with respect to our estimated proved reserves by geographic area as of December 31, 2009 based on estimates made in a reserve report prepared by Ryder Scott Company, L.P.

	Estimated Proved Developed Reserve Quantities	Estimated Proved Undeveloped Reserve Quantities	Estimated Proved

Geographic Area	Natural Gas (Bcf)	Oil (MMBbls)	NGLs (MMBbls)	Total (Bcfe)	Natural Gas (Bcf)	Oil (MMBbls)	NGLs (MMBbls)	Total (Bcfe)	Reserve Quantities Total (Bcfe)
Permian Basin	84.7	16.4	15.7	277.1	63.9	16.7	12.3	237.9	515.0
Gulf Coast	43.2	0.7	2.0	59.5	16.3	0.2	0.8	22.1	81.6
Gulf of Mexico Deepwater	111.5	3.5	0.5	135.7	9.3	2.8		26.0	161.7
Gulf of Mexico Shelf	160.2	10.3	1.9	233.2	72.9	1.2	0.3	81.9	315.1
Other onshore	7.2	0.6		10.9	2.2	0.1		2.8	13.7
Total	406.8	31.5	20.1	716.4	164.6	21.0	13.4	370.7	1,087.1

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Geographic Area	Developed	PV10 Value(1) Undeveloped (In millions)	Total	Standardized Measure (In millions)
Permian Basin	$ 440.8	$ 51.6	$ 492.4	
Gulf Coast	103.8	9.8	113.6	
Gulf of Mexico Deepwater	324.8	54.7	379.5	
Gulf of Mexico Shelf	458.0	33.0	491.0	
Other onshore	22.6	3.1	25.7	
Total	$ 1,350.0	$ 152.2	$ 1,502.2	$ 1,468.4

(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 or standardized measure 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, 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, 2009	2008 (In millions)	2007
Present value of estimated future net revenues (PV10)	$ 1,502.2	$ 1,667.5	$ 3,064.2
Future income taxes, discounted at 10%	(33.8)	(184.5)	(832.3)
Standardized measure of discounted future net cash flows	$ 1,468.4	$ 1,483.0	$ 2,231.9

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.

A combination of technologies is used in estimating our proved reserves. Approximately 60% of our proved reserves as of December 31, 2009 were estimated using the performance method and the balance were estimated using the volumetric method. A combination of geological structural and isochore maps, well logs, core analyses, and pressure measurements support the reserves estimates. In general, reserves attributable to producing wells or reservoirs were estimated by performance methods such as decline curve analysis, material balance or reservoir simulation which used extrapolations of historical production and pressure data available through December 2009. In certain cases, producing reserves were more appropriately estimated by the

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volumetric method, such as when there was inadequate historical performance data to establish a definitive trend. Certain reserves attributable to non-producing and undeveloped reservoirs were estimated by the volumetric method using pertinent well and seismic data available through December 31, 2009.

The process of estimating reserves is complex and requires many assumptions as discussed below in Item 1A. Risk Factors. As a result, we have developed internal controls for estimating and recording reserves. These controls require reserves to be in compliance with SEC definitions and guidance. Our controls assign responsibility for compliance in reserves bookings to our reservoir engineering team. Annual estimates of our proved reserves and future production and income attributable to those reserves are prepared using the economic software package Aries^{tm} System Petroleum Economic Evaluation Software, a copyrighted program of Halliburton. Our reservoir engineering team coordinates with our land, marketing and accounting departments and those of our executive officers responsible for given operating areas in reconciling year-over-year reserve changes for each of our fields. These efforts are designed to help ensure that our database reflects information pertaining to performance revisions, production, drilling, acquisitions, sales, recompletions, wells, working interests, net revenue interests, lease operating expenses, taxes, capital costs and PV10 of future net revenues. Our reservoir engineering team certifies this information to a third-party independent reservoir engineering firm in connection with its preparation of our proved reserve estimates. Our Chief Operating Officer reviews the third-party firm s estimates of our proved reserves and ultimately certifies our acceptance of those estimates. These estimates also are presented to our board of directors in connection with its consideration of our annual report on Form 10-K.

Our reservoir engineering team is led by Richard A. Molohon, Vice President Reservoir Engineering. He is the technical person primarily responsible internally for overseeing the preparation of our reserves estimates by Ryder Scott Company, L.P. Mr. Molohon has been a Registered Professional Engineer in Texas since 1983, joined us as a Senior Reservoir Engineer in 1995 and is a member of the Society of Petroleum Engineers. For addition information on Mr. Molohon s background, see Executive Officers below under Item 4. Mr. Molohon reports to our Chief Operating Officer who reports to our Chairman, Chief Executive Officer and President. No portion of the compensation of our management or the reservoir engineering team is directly dependent on the quantity of reserves booked.

We engage Ryder Scott Company, L.P. to prepare 100% of our proved reserves estimates. The technical person at Ryder Scott Company, L.P. primarily responsible for overseeing the preparation of our reserves estimates is Edward J. Gibbon, a Senior Vice President of Ryder Scott Company, L.P. Mr. Gibbon earned a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines in 1968 and is a Licensed Professional Engineer in the State of Texas and a Registered Professional Engineer in the State of Louisiana. He also is a member of the Society of Petroleum Evaluation Engineers, the Society of Petroleum Engineers, and the Society of Petrophysicists and Well Log Analysts. Additional information on Mr. Gibbon s background is contained in the report of Ryder Scott Company, L.P. filed as an exhibit to this Annual Report on Form 10-K. Mr. Gibbon meets the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Proved Undeveloped Reserves

As of December 31, 2009, our estimated proved undeveloped reserves (PUDs) totaled 370.7 Bcfe or 34.0% of our total estimated proved reserves and consisted of 164.6 Bcf of gas, 21.0 MMBbls of oil and 13.4 MMBbls of NGLs. Approximately 64.2% of these PUDs were in the Permian Basin, 22.1% were in the Gulf of Mexico shelf, 7.0% were in the Gulf of Mexico deepwater, 6.0% were in the Gulf Coast and 0.7% were in other onshore properties.

During 2009, we converted approximately 49.7 Bcfe or 16.8% of our total PUDs as of December 31, 2008 to proved developed reserves as of December 31, 2009, of which approximately 79.9%, 13.3% and 6.8% were in the Gulf of

Mexico shelf, Gulf of Mexico deepwater and Permian Basin, respectively. We also developed approximately 7.7 Bcfe during 2009 that were estimated proved developed reserves in the Permian

Basin at December 31, 2009 but were not included in our year-end 2008 proved reserves. We spent approximately $125.8 million during 2009 on development activities to convert PUDs to proved developed reserves. At December 31, 2009, we eliminated approximately 39.7 Bcfe or 13.4% of our total PUDs as of December 31, 2008, of which approximately 56.9%, 23.9% and 19.2% were in the Gulf of Mexico shelf, Permian Basin and Gulf of Mexico deepwater, respectively, primarily due to pricing (59.1% of the total eliminated) and performance (40.9% of the total eliminated) considerations.

Of our total 370.7 Bcfe of PUDs as of December 31, 2009, approximately 20.2 Bcfe or 5.4% remained undeveloped for more than five years. Of the 20.2 Bcfe, approximately 62.2% were in the Gulf of Mexico deepwater awaiting expected conversion to proved developed reserves upon a side track updip after the current wellbore depletes, and the balance were in the Spraberry (Aldwell Unit) field in the Permian Basin where we have been drilling continuously since 2002.

The following tables present our natural gas, oil and NGL production and revenue, excluding the effects of hedging, by area for the indicted periods. The tables excludes the properties of the Edge subsidiaries we acquired on December 31, 2009.

	Year Ended December 31,		
	2009	**2008**	**2007**
Production			
Permian Basin:			
Natural gas (Bcf)	5.0	4.0	3.7
Oil (MBbls)	1,468.0	1,242.8	861.2
NGLs (MBbls)	744.0	578.5	387.3
Total Natural Gas Equivalent (Bcfe)	18.3	14.9	11.2
Gulf of Mexico Deepwater:			
Natural gas (Bcf)	42.1	27.7	14.7
Oil (MBbls)	1,427.0	1,850.5	1,301.9
NGLs (MBbls)	362.2	264.7	126.2
Total Natural Gas Equivalent (Bcfe)	52.8	40.4	23.3
Gulf of Mexico Shelf:			
Natural gas (Bcf)	43.7	48.1	49.4
Oil (MBbls)	1,576.5	1,787.7	2,050.3
NGLs (MBbls)	371.7	714.7	686.3
Total Natural Gas Equivalent (Bcfe)	55.4	63.1	65.8
Total Production:			
Natural gas (Bcf)	90.8	79.8	67.8
Oil (MBbls)	4,471.5	4,881.0	4,213.4
NGLs (MBbls)	1,477.9	1,557.9	1,199.8
Total Natural Gas Equivalent (Bcfe)	126.5	118.4	100.3

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	Year Ended December 31, 2009	2008	2007
		(In thousands)	
Revenue (excluding the effects of hedges)			
Permian Basin:			
Natural gas	$ 19,775	$ 31,339	$ 25,153
Oil	87,153	122,005	61,528
NGLs	23,794	30,765	17,871
Total	$ 130,722	$ 184,109	$ 104,552
Gulf of Mexico Deepwater:			
Natural gas	$ 168,564	$ 271,979	$ 104,840
Oil	86,524	180,131	90,631
NGLs	12,611	15,053	5,538
Total	$ 267,699	$ 467,163	$ 201,009
Gulf of Mexico Shelf:			
Natural gas	$ 176,063	$ 467,099	$ 346,078
Oil	97,164	190,504	145,634
NGLs	12,516	39,897	30,783
Total	$ 285,743	$ 697,500	$ 522,495
Total Revenues:			
Natural gas	$ 364,402	$ 770,417	$ 476,071
Oil	270,841	492,640	297,793
NGLs	48,921	85,715	54,192
Total	$ 684,164	$ 1,348,772	$ 828,056

Average Sales Prices and Production Costs

The following table presents our average realized sales prices and average production costs for the indicated periods. The table does not include operating results of the subsidiaries we acquired from Edge on December 31, 2009.

	Year Ended December 31, 2009	2008	2007
Average realized sales prices:			
Natural gas (per Mcf)	$ 6.08	$ 9.31	$ 7.88
Oil (per Bbl)	70.59	86.02	67.50
Natural gas liquids (per Bbl)	33.10	55.02	45.16
Total natural gas equivalent ($/Mcfe)	7.25	10.54	8.71

Average realized sales prices excluding the effects of hedging:			
Natural gas (per Mcf)	$ 4.01	$ 9.66	$ 7.02
Oil (per Bbl)	60.57	100.93	70.68
Natural gas liquids (per Bbl)	33.10	55.02	45.16
Total natural gas equivalent ($/Mcfe)	5.41	11.39	8.26
Average production costs per Mcfe:	$ 1.97	$ 1.96	$ 1.52

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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, 2009 and December 31, 2008.

	Year Ended December 31,			
	2009		2008	
	Gross	Net	Gross	Net
Oil	1,037.0	792.0	936.0	733.0
Natural gas	380.0	213.8	154.0	90.2
Total	1,417.0	1,005.8	1,090.0	823.2

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, 2009.

	Year Ended December 31, 2009					
	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin	103,507	81,861	165,894	66,256	269,401	148,117
Gulf Coast	64,229	27,273	37,689	19,967	101,918	47,240
Gulf of Mexico Deepwater	87,757	39,610	432,691	226,386	520,448	265,996
Gulf of Mexico Shelf	697,131	383,911	313,684	228,936	1,010,815	612,847
Other Onshore	19,800	7,984	104,511	81,145	124,311	89,129
Total	972,424	540,639	1,054,469	622,690	2,026,893	1,163,329

The following table sets forth that portion of our onshore and offshore undeveloped acreage as of December 31, 2009 that is subject to expiration absent drilling activity during the three years ended December 31, 2012 and thereafter.

	Undeveloped Acreage Subject to Expiration in the Year Ended December 31,							
	2010		2011		2012		Thereafter	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian Basin	22,735	16,950	29,653	27,229	3,526	3,450	49,840	17,943
Gulf Coast	22,460	19,505	17,256	13,164	224	516	7,200	3,612
Gulf of Mexico Deepwater	57,600	17,856	34,560	17,280	34,560	4,212	305,971	186,930
	32,665	22,864	101,336	73,508	32,454	25,150	147,229	107,414

Gulf of Mexico Shelf								
Other Onshore	32,370	25,884	6,087	5,472	1,765	1,424	921	513
Total	167,830	103,059	188,892	136,653	72,529	34,752	511,161	316,412

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Drilling Activity

Certain information with regard to the number of wells drilled during the years ended December 31, 2009, 2008 and 2007 is set forth below. The number of wells drilled refers to the number of wells completed at any time during a given year, regardless of when drilling was initiated. The following table does not include any drilling activity of the Edge subsidiaries we acquired on December 31, 2009.

	Year Ended December 31,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Productive	10.00	5.97	15.00	8.59	11.00	5.96
Dry	10.00	7.00	5.00	2.98	8.00	4.91
Total	20.00	12.97	20.00	11.57	19.00	10.87
Development wells:						
Productive	33.00	30.08	125.00	88.93	121.00	60.43
Dry						
Total	33.00	30.08	125.00	88.93	121.00	60.43
Extension wells:						
Productive	14.00	9.49	3.00	3.00		
Dry						
Total	14.00	9.49	3.00	3.00		
Total wells:						
Productive	57.00	45.54	143.00	100.52	132.00	66.39
Dry	10.00	7.00	5.00	2.98	8.00	4.91
Total	67.00	52.54	148.00	103.50	140.00	71.30

As of February 22, 2010, the following wells were drilling:

Well Name	Operator	Approximate Working Interest	Location	Gross	Net
West Cameron 112 A-2	Mariner	55%	Shelf	1.00	0.55
South Marsh 11 #58	Mariner	100%	Shelf	1.00	1.00
Green Canyon 903 #1	Anadarko	13%	Deepwater	1.00	0.13
Cathey 2906 #1	Mariner	61%	Permian Basin	1.00	0.61
SRH 1609	Mariner	100%	Permian Basin	1.00	1.00

Keathley 46 #2	Mariner	100%	Permian Basin	1.00	1.00
Currie 23 #1	Mariner	50%	Permian Basin	1.00	0.50
SRH 1705	Mariner	100%	Permian Basin	1.00	1.00
Cowden E #5	Mariner	55%	Permian Basin	1.00	0.55

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 NGLs production is sold to a variety of customers under short-term marketing arrangements at market-based

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prices. The following table lists customers accounting for more than 10% of our total revenues for the year indicated.

Customer	Percentage of Total Revenues for Year Ended December 31, 2009	2008	2007
Williams Gas and affiliates	12%	5%	<1%
ChevronTexaco and affiliates	13%	16%	23%
Plains Marketing LP	11%	5%	7%
Shell	9%	10%	10%

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

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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 were ordered by the MMS to pay royalties for natural gas produced in some of those years. However, we challenged the MMS s authority to include price thresholds in six of our post-Act leases awarded in 1996 and 1997 because we believe that post-Act leases are entitled to automatic royalty relief under the RRA, regardless of commodity prices. In February 2010, the MMS withdrew its orders in respect of these leases, closing the matter in our favor. For more information, 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 and Crude Oil

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 and at just and reasonable rates 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.

The FERC also regulates interstate crude oil pipeline transportation rates and service conditions under the Interstate Commerce Act, which affect the marketing of crude oil produced by us and the revenues received by us for sales of such oil. The FERC requires interstate pipelines to provide non-discriminatory, common carrier service at just and reasonable rates. The intra-state transportation of crude oil is subject to state regulatory jurisdiction. FERC and the state agencies modify their transportation policies and regulations from time to time. Also, in the Energy Policy Act of 2007, Congress directed the Federal Trade Commission to impose regulations prohibiting deceptive on manipulative practices relating to the sale of crude oil. In 2009, the FTC issued a rule similar to FERC s anti-manipulation rule for gas.

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 $75.0 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 $35.0 million to cover liabilities related to an oil spill. The amount of financial assurance required under the OPA may be increased up to $150.0 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. Except as outlined below regarding climate change issues, 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.

Climate Change. There is increasing attention in the United States and worldwide concerning the issue of climate change and the effect of emissions of greenhouse gases (GHG), in particular from the combustion of fossil fuels. Under the Clean Air Act and various state analogues, regulations limiting GHG emissions or imposing reporting obligations with respect to such emissions have been proposed or finalized. On October 30, 2009, EPA published a final rule requiring the reporting of GHG emissions from specified large sources in the United States beginning in 2011 for emissions occurring in 2010. In addition, on December 15, 2009, EPA published a Final Rule finding that current and projected concentrations of six key GHGs in the atmosphere threaten public health and welfare of current and future generations. EPA also found that the combined emissions of these GHGs from new motor vehicles and new motor vehicle engines contribute to the GHG pollution that threatens public health and welfare. This Final Rule, also known as EPA s Endangerment Finding, does not impose any requirements on industry or other entities directly; however, after the rule s January 14, 2010 effective date, EPA will be able to finalize motor vehicle GHG standards, the effect of which could reduce demand for motor fuels refined from crude oil. Finally, according to EPA, the final motor vehicle GHG standards will trigger construction and operating permit requirements for stationary sources. As a result, EPA has proposed to tailor these programs such that only stationary sources, including refineries, that emit over 25,000 tons of GHGs per year will be subject to air permitting requirements. In addition, on September 22, 2009, EPA issued a Mandatory Reporting of Greenhouse Gases final rule (Reporting Rule).

The Reporting Rule establishes a new comprehensive scheme requiring operators of stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent GHGs to inventory and report their GHG emissions annually on a facility-by-facility basis. Further, proposed legislation has been introduced in Congress that would establish an economy-wide cap on emissions of GHGs in the United States and would require most sources of GHG emissions to obtain GHG emission allowances corresponding to their annual emissions of GHGs. Any limitation on emissions of GHGs from our equipment or operations could require us to incur costs to reduce such emissions. 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. Moreover, incentives to conserve or use alternative energy sources could reduce demand for fossil fuels, resulting in a decrease in demand for our products.

Climate change also poses potential physical risks, including an increase in sea level and changes in weather conditions, such as an increase in changes in precipitation and extreme weather events. To the extent that such unfavorable weather conditions are exacerbated by global climate change or otherwise, our operations may be adversely affected to a greater degree than we have previously experienced, including increased delays and costs. However, the uncertain nature of changes in extreme weather events (such as increased frequency, duration, and severity) and the long period of time over which any changes would take place make estimating any future financial risk to our operations caused by these physical risks of climate change extremely challenging.

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.

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Employees

As of December 31, 2009, we had 328 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

Current Insurance Against Hurricanes

Mariner is a member of OIL Insurance Limited (OIL), an energy industry insurance cooperative, which provides Mariner windstorm insurance coverage. During 2009, the coverage was subject to a $10.0 million per-occurrence deductible, a $250.0 million per-occurrence loss limit, and a $750.0 million industry aggregate per-event loss limit. Effective January 1, 2010, the coverage is subject to a per-occurrence deductible which remains under consideration, a $150.0 million per-occurrence loss limit per member, an annual maximum of $300.0 million per member, and a $750.0 million industry aggregate per-event loss limit. In addition, annual industry windstorm losses exceeding $300.0 million will be mutualized among windstorm members in two pools, one for offshore and one for onshore, with future premiums based upon a pool s loss experience and a member s weighted percent of the pool s asset base. Mariner anticipates these changes to increase its loss retention by approximately $100.0 million for windstorm losses, which it expects to either self insure, insure through the commercial market, insure through the purchase of additional OIL coverage or a combination of these.

Each year, Mariner considers whether to purchase from the commercial market supplemental or excess insurance which in the past has provided coverage when OIL limits have been exceeded (see discussion below under Hurricanes Katrina and Rita (2005)). The supplemental insurance coverage offered by the commercial market in 2009 would not have provided similar coverage and Mariner elected not to purchase it when it expired on June 1, 2009. Mariner believes its assets are sufficiently insured through OIL and Mariner s expected ability to cover losses in excess of OIL coverage. Mariner intends to monitor the commercial market for insurance that would, based on Mariner s historical experience, cover its expected hurricane-related risks on a cost-effective basis once OIL limits are exceeded.

As of December 31, 2009, Mariner accrued approximately $48.0 million for an OIL withdrawal premium contingency. As part of its OIL membership, Mariner 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, Mariner periodically reassesses the sufficiency of its accrued withdrawal premium based on OIL s periodic calculation of the potential withdrawal premium in light of past losses, and Mariner may adjust its accrual accordingly in the future. 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 has entered into such a security agreement, granting to OIL a senior security interest in up to the next $50.0 million in excess of $100.0 million of Mariner s Hurricane Ike claim proceeds payable by OIL. Mariner has 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, Mariner 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. Mariner estimates that repairs and plugging and abandonment costs resulting from Hurricane Ike will total approximately $160.0 million net to Mariner s interest. OIL has advised Mariner that industry-wide damages from Hurricane Ike are expected to substantially exceed OIL s $750.0 million industry aggregate per event loss limit and that OIL expects to initially prorate the payout of all OIL members Hurricane Ike claims at approximately 50%, subject to further adjustment. OIL also has indicated that the scaling factor it expects to apply to Mariner s Hurricane Ike claims will result in settlement at less than 70%. Mariner expects that approximately 75% of the shortfall in its primary insurance coverage will be covered under its commercial excess coverage. In respect of Hurricane Ike

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claims that Mariner made through December 2009, it received approximately $30.6 million from OIL and $9.7 million from excess carriers. Although in 2009 Mariner started receiving payment in respect of its Hurricane Ike claims, due to the magnitude of the storm and the complexity of the insurance claims being processed by the insurance industry, Mariner expects to maintain a potentially significant insurance receivable through 2010 while it actively pursues settlement.

Hurricanes Katrina and Rita (2005)

In 2005, Mariner 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, Mariner has incurred approximately $208.6 million in hurricane expenditures resulting from Hurricanes Katrina and Rita, of which $130.6 million were capitalized expenditures and $78.0 million were hurricane-related abandonment costs.

Applicable insurance for Mariner s Hurricane Katrina and Rita claims with respect to the Gulf of Mexico assets acquired in March 2006 was provided by OIL. Mariner s coverage for such properties was subject to a deductible of $5.0 million per occurrence and a $1.0 billion industry-wide loss limit per occurrence. OIL advised Mariner that the aggregate claims resulting from each of Hurricanes Katrina and Rita were expected to exceed the $1.0 billion per occurrence loss limit and that therefore Mariner s insurance recovery was expected to be reduced pro-rata (approximately 47% for Katrina and 67% for Rita) with all other competing claims from the storms. During 2008, Mariner settled its Katrina and Rita claims with its excess insurers for a one-time cash payment of $48.5 million.

As of December 31, 2009, Mariner had recovered approximately $137.0 million in respect of Hurricanes Katrina and Rita, of which $88.5 million was paid by OIL and $48.5 million was paid by excess insurers. Although Mariner has received full and final settlement of its insurance claims in respect of Hurricanes Katrina and Rita as of December 31, 2009, it may receive from OIL a relatively immaterial additional amount in respect of Hurricane Rita after OIL finally adjusts all of its members Hurricane Rita claims.

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.

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.

Acquisition of properties. Cost incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers fees, recoding fees, legal costs, and other costs incurred in acquiring properties.

Analogous reservoir. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. This definition has been abbreviated from the applicable definition contained in Rule 4-10(a)(2) of Regulation S-X.

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.

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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 production of oil or gas, or in the case of a dry well, the reporting to the appropriate authority that the well has been abandoned.

Condensate. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

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, on December 31, 2009).

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

Developed reserves. Reserves of any category that can be expected to be recovered. This definition has been abbreviated from the definition of Developed oil and gas reserves contained in Rule 4-10(a)(6) of Regulation S-X.

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 has been abbreviated from the applicable definition contained in Rule 4-10(a)(7) of Regulation S-X.

Development project. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a 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 well. An exploratory, development or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

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

Economically producible. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. This definition has been abbreviated from the applicable definition contained in Rule 4-10(a)(10) of Regulation S-X.

Estimated ultimate recovery (EUR). Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

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

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drilling exploratory wells and exploratory-type stratigraphic test wells. This definition has been abbreviated from the applicable definition contained in Rule 4-10(a)(12) of Regulation S-X.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this glossary.

Extension well. A well drilled to extend the limits of 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 a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. This definition has been abbreviated from the applicable definition contained in Rule 4-10(a)(15) of Regulation S-X.

Gas. Natural gas.

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

MMBbls. 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. A net acre or well is deemed to exist when the sum of fractional ownership working interests in gross acres or wells equals one.

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.

Oil. Crude oil. Unless otherwise stated, references to oil include condensate.

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

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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.

Possible reserves. Those additional reserves that are less certain to be recovered than probable reserves. This definition has been abbreviated from the applicable definition contained in Rule 4-10(a)(17) of Regulation S-X.

Present value of estimated future net revenues or PV10. 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.

Probable reserves. Those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. This definition has been abbreviated from the applicable definition contained in Rule 4-10(a)(18) of Regulation S-X.

Production costs. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. This definition has been abbreviated from the applicable definition contained in Rule 4-10(a)(20) of Regulation S-X.

Productive well. An exploratory, development or extension well that is not a dry well. Productive wells include producing wells and wells mechanically capable of production.

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 area. The part of a property to which proved reserves have been specifically attributed.

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

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

Proved properties. Properties with proved reserves.

Proved reserves. Those quantities of crude oil and gas, which, by analysis of that geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. This definition has been abbreviated from the definition of Proved oil and gas reserves contained in Rule 4-10(a)(22) of Regulation S-X.

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

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Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. This definition abbreviated from the applicable definition contained in Rule 4-10(a)(26) of Regulation S-X.

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.

Service well. A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

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.

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.

Stratigraphic test well. A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geological condition. The classification also includes test identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as exploratory type if not drilled in a known area or development type if drilled in a known area.

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.

Tcfe. Trillion cubic feet equivalent of natural gas.

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

Undeveloped reserves. Reserves of any category 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 has been abbreviated from the definition of Undeveloped oil and gas reserves contained in Rule 4-10(a)(31) of Regulation S-X.

Unproved properties. Properties with no 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

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 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 above 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.

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.

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. 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 above 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 generally base the estimated discounted future net cash flows from our estimated proved reserves on an unweighted arithmetic average of the first-day-of-the month price for each month during the 12-month calendar year and year-end costs. 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. During the year ended December 31, 2009, 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 $754.3 million. See below Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates Oil and Gas Properties, and Item 8, Note 1 Summary of Significant Accounting Policies in the Notes to the Consolidated Financial Statements 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, 2009. 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.

Of our total estimated proved reserves, approximately 30% are undeveloped and ultimately may be reclassified as unproved or not be developed, and 20% are developed non-producing and may not be produced.

As of December 31, 2009, approximately 30% of our total estimated proved reserves were undeveloped. The SEC generally requires that reserves classified as proved undeveloped be capable of conversion into proved developed within five years of classification unless specific circumstances justify a longer time. Approximately 7.8% of our estimated proved undeveloped reserves as of December 31, 2009 have been classified as such for at least four years. Proved undeveloped reserves that are not timely developed are subject to possible reclassification as non-proved reserves. Substantial downward adjustments to our estimated proved reserves could have a material adverse effect on our financial condition and results of operations, and lower our bank borrowing base and reduce our access to capital. In addition to our proved undeveloped reserves, as of December 31, 2009 approximately 20% of our total estimated proved reserves were developed non-producing. Not all of our undeveloped or developed non-producing reserves ultimately may be developed or 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.

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

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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 above Item 1. Business Properties Gulf of Mexico Deepwater Operations 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. 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.

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

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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.

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 above 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 plugging 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

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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 certain insurance policies or procure other desirable insurance on commercially reasonable terms, if at all. See above Item 1. Business Insurance Matters.

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 Hurricane Ike. See above Item 1. Business Insurance Matters and below Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources for more information.

The proposed U.S. federal budget for fiscal year 2010 includes certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

The Office of Management and Budget s proposed U.S. federal budget for fiscal year 2010 repeals many tax incentives and deductions that are currently used by U.S. oil and gas companies and imposes new taxes. The provisions include: elimination of the ability to fully deduct intangible drilling costs in the year incurred; increases in the taxation of foreign source income; levy of an excise tax on Gulf of Mexico oil and gas production; repeal of the manufacturing tax deduction for oil and gas companies; and increase in the geological and geophysical amortization period for independent producers. Should some or all of these provisions become law, our taxes will increase, potentially significantly, which would have a negative impact on our net income and cash flows. Since none of these proposals have yet to be voted on or become law, we do not know the ultimate impact these proposed changes may have on our business.

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.

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.

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, and the issuance of debt and equity securities. 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

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disadvantage relative to other competitors. Additionally, if revenues decrease as a result of lower oil or natural gas prices, operating difficulties or declines in reserves, our ability to obtain the capital necessary to undertake or complete future exploration and development programs and to pursue other opportunities may be limited. This could also result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could result in a decline in our oil and natural gas reserves.

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

We expect our earnings and cash flow to vary significantly from year to year due to the cyclical nature of our industry. 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 several 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.

Ownership of property interests and production operations in areas outside the United States is subject to foreign currency risks.

To the extent we generate revenue outside the U.S., our operations will be sensitive to fluctuations in foreign currency exchange rates, particularly through the weakening of the U.S. dollar relative to other currencies. We may experience currency exchange or other financial losses where we do not take or unsuccessfully take protective measures against exposure to a foreign currency, such as through currency exchange contracts. We also may incur losses as a result of controls over currency exchange or controls over the repatriation of income or capital. Our financial statements, presented in U.S. dollars, are affected by foreign currency fluctuations through both translation risk and transaction risk.

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; Lafayette, Louisiana; and Calgary, Canada. As of December 31, 2009, our leases covered approximately 102,192 square feet, 6,580 square feet, 14,376 square feet and 3,850 square feet of office space in Houston, Midland, Lafayette and Calgary, respectively. The leases run through October 31, 2018, October 31, 2011, September 30, 2013 and November 30, 2014 in Houston, Midland, Lafayette and Calgary, respectively. The total annual costs of our leases for 2009 were approximately $3.2 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 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, September 2008 and August 2009, 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 2008, and, accordingly, that royalties were due under such leases on oil and gas produced in those years (the Orders). Mariner and MERI believed that the MMS did not have the statutory authority to include commodity price threshold language in leases governed by Section 304 of the RRA, withheld payment of royalties, and challenged the MMS s authority in administrative appeals respecting those leases subject to the Orders. In February 2010, the MMS notified us that it withdrew the Orders, rendering our appeals moot and closing the matter in our favor.

The enforceability of the price threshold provisions in leases granted pursuant to Section 304 of the RRA was being litigated in several administrative appeals filed by other companies in addition to us, as well as in *Kerr-McGee Oil & Gas Corp. v. Allred*, 554 F.3d 1082 (5th Cir.), *cert denied*, *Dep t of the Interior v. Kerr-McGee Oil & Gas Corp.*, 130 S. Ct. 236 (2009). 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 (DOI) 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. On April 14, 2009, the Fifth Circuit denied the DOI s Petition for Rehearing En Banc. On July 13, 2009, the DOI filed a Petition for a Writ of Certiorari with the Supreme Court of the United States. On October 5, 2009, the U.S. Supreme Court denied the Petition for a Writ of Certiorari. Accordingly, the Fifth Circuit s judgment that the price threshold provisions are unlawful and unenforceable under Section 304 of the RRA is final. This judgment was the basis upon which the MMS withdrew the Orders.

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

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

Not applicable.

Executive Officers of the Registrant

The following table sets forth the names, ages (as of February 22, 2010) 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	52	Chairman of the Board, Chief Executive Officer and President
Dalton F. Polasek	58	Chief Operating Officer
Jesus G. Melendrez	51	Senior Vice President, Chief Commercial Officer, Acting Chief Financial Officer and Treasurer
Mike C. van den Bold	47	Senior Vice President and Chief Exploration Officer
Judd A. Hansen	54	Senior Vice President Shelf and Onshore
Teresa G. Bushman	60	Senior Vice President, General Counsel and Secretary
Cory L. Loegering	54	Senior Vice President Deepwater
Murray W. Grigg	54	Vice President Unconventional Resources
Emily R. McClung	44	Vice President Human Resources
Michael C. McCullough	64	Vice President Acquisitions and Divestitures
Richard A. Molohon	55	Vice President Reservoir Engineering
Kenneth E. Moore, Jr.	63	Vice President Onshore Land
Charles H. Odom	56	Vice President Offshore Land and Business Development
R. Cris Sherman	49	Vice President and Chief Accounting Officer

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. He is a director of the Bellville Greater Hospital Foundation and The Association of Former Students of Texas A&M University.

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.

Jesus G. Melendrez Mr. Melendrez was named Senior Vice President Chief Commercial Officer and appointed Acting Chief Financial Officer and Treasurer in October 2009. He was promoted to Senior Vice President Corporate Development in April 2006, serving in that office until October 2009, and served as Vice President Corporate Development from July 2003 to April 2006. Mr. Melendrez also served as a director of Mariner from April 2000 to July 2003. From February 2000 until July 2003, Mr. Melendrez was a Vice President of Enron North America Corp. in the Energy Capital Resources group where he managed the group s portfolio of oil and gas investments. He was a Senior Vice President of Trading and Structured Finance with TXU Energy Services from 1997 to 2000, and from 1992 to 1997, Mr. Melendrez was employed by Enron in various commercial positions in the areas of domestic oil and gas financing and international project development. From 1980 to 1992, Mr. Melendrez was employed by Exxon in various reservoir engineering and planning positions.

Mike C. van den Bold Mr. van den Bold was promoted to Senior Vice President and Chief Exploration Officer in April 2006 and served as Vice President and Chief Exploration Officer from April 2004 to April 2006. From October 2001 to April 2004, he served as Vice President Exploration. Mr. van den Bold joined Mariner in July 2000 as Senior Development Geologist. From 1996 to 2000, Mr. van den Bold worked for British-Borneo Oil & Gas plc. He began his career at British Petroleum. Mr. van den Bold has 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.

Murray W. Grigg Mr. Grigg was promoted to Vice President Unconventional Resources effective March 2010. He joined Mariner in June 2009 as Director, Unconventional Resources with more than 30 years of industry experience as a petroleum engineer. From July 2005 to June 2009, he was Executive Vice President of Kerogen Resources, Inc. which he co-founded to specialize in identifying unconventional oil and gas shale opportunities, particularly in tight gas sands, gas shales and coal bed methane plays in the United States and Canada. He focused on these types of plays as an Engineering Advisor with EnCana Oil & Gas (USA) from 2004 to July 2005, Chief Exploration Engineer with Tom Brown, Inc. from 2003 to 2004, Chief Exploration Engineer with EOG Resources Inc. from 2001 to 2003, and Technical Specialist with EOG Resources Canada, Inc. from 1998 to 2001. Mr. Grigg is a member of the American Association of Petroleum Geologists and Society of Petroleum Engineers.

Emily R. McClung Ms. McClung was promoted to Vice President Human Resources effective March 2010, serving as Director of Human Resources from August 2007 to March 2010, and Human Resources Manager from July 2003 to August 2007. She also was employed by Mariner in human resources from November 1997 to June 2002. From June 2002 to July 2003, she was Payroll/Benefits Manager of T3 Energy Services. From August 1988 to November 1997, she was employed by Bank One Texas, N.A. in customer service, human resource and trust support capacities, most recently as Trust Account Specialist in the administration of employee benefit trust plans.

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

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.

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.

Charles H. Odom Mr. Odom joined Mariner in April 2009 as Vice President Offshore Land and Business Development with more than 30 years of industry experience. From October 2007 to February 2009,

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he was Chief Executive Officer of White Bay Energy, LLC, which he co-founded to focus on oil and gas exploration and development opportunities in South Texas. From April 2006 to August 2007, Mr. Odom was the Vice President of Santos USA responsible for managing oil and gas assets and projects along the Texas Gulf Coast, on and offshore, and in the U.S. Rocky Mountain region until its assets were sold. From August 2005 to August 2007, he was an independent consultant. In October 2000, Mr. Odom co-founded Gryphon Exploration Company, which focused on the shallow waters in the Gulf of Mexico, serving as its Vice President of Land and Business Development from October 2000 until it was sold in August 2005 to an international oil company. From September 1991 to October 2000, he was President of C. H. Odom Company, a management consulting firm specializing in oil and gas exploration and development transactions in the Gulf of Mexico and onshore Texas.

R. Cris Sherman Mr. Sherman joined Mariner in October 2009 as Vice President and Chief Accounting Officer with more than 25 years of experience as a Certified Professional Accountant in the energy industry. He was a partner at the professional services firm Sirius Solutions, L.L.L.P. from January 2007 to October 2009, and employed as a director of Sirius from April 2004 until January 2007. From March 2003 to April 2004, he was a Director of Reliant Resources, Inc., primarily responsible for managing accounting for the retail supply group. From February 2002 to March 2003, he was Executive Director Accounting Policy of UBS Warburg Energy, LLC. From July 1998 to February 2002, Mr. Sherman provided technical accounting and transaction support primarily to the wholesale gas, power trading and finance businesses of Enron North America Corp., most recently as Vice President Transaction Support in 2001 to 2002, and as a Senior Director and Director before then. He was Director Internal Audit of Dynegy, Inc. from June 1997 to July 1998. He served in various positions with Eastex Energy Inc. from 1985 to 1988 and 1990 to 1996, most recently as Vice President and Chief Financial Officer from January 1995 to May 1996 and Vice President and Controller from June 1993 to January 1995. From May 1988 to November 1990, he was Vice President and Controller of Houston Gas Exchange 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
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
2009	First Quarter	$ 12.59	$ 6.85
	Second Quarter	15.53	7.87
	Third Quarter	15.19	9.88
	Fourth Quarter	16.09	11.47

As of February 22, 2010, there were 774 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 2008 or 2009. Refer below 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 Item 8 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**	**12/31/09**
Mariner Energy, Inc.	$ 100.00	$ 96.69	$ 112.88	$ 50.32	$ 57.28
S&P 500 Index	$ 100.00	$ 110.18	$ 114.07	$ 70.17	$ 86.63
Peer Group(2)	$ 100.00	$ 96.98	$ 103.61	$ 37.10	$ 43.61

(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. The 2009 data for Energy Partners, Ltd. reflects adjustment for its issuance on September 21, 2009 of 0.06166332 share of new common stock in exchange for each former one share of common stock outstanding before its emergence from bankruptcy.

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, 2009 to October 31, 2009(1)	41,032	$ 15.74		
November 1, 2009 to November 30, 2009(1)		$		
December 1, 2009 to December 31, 2009(1)	495	$ 13.35		
Total	41,527	$ 15.68		

(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.*

The selected financial data table below shows our historical consolidated financial data as of and for each of the five years in the period ended December 31, 2009. The historical consolidated financial data are derived from Mariner s audited Consolidated Financial Statements, including the consolidated balance sheets at December 31, 2009 and 2008 and the related consolidated statements of operations and cash flows for each of the three years in the period ended December 31, 2009, included herein. 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.

	Year Ended December 31,				
	2009	2008	2007	2006	2005
	(In thousands, except per share data)				
Statement of Operations Data(1):					
Total revenues(2)	$ 942,941	$ 1,300,507	$ 874,765	$ 659,505	$ 199,710
Operating expenses(3)	282,353	264,832	174,522	105,739	32,218
Depreciation, depletion and amortization	399,400	467,265	384,321	292,180	59,469
General and administrative expense	79,960	60,613	42,151	33,622	36,766
Operating (loss) income(4)	(581,403)	(381,712)	268,710	227,470	69,168
Interest expense, net of amounts capitalized	70,134	56,398	54,665	39,649	8,172
(Benefit) Provision for income taxes	(224,370)	(48,223)	77,324	67,344	21,294
Net (loss) income attributable to Mariner Energy, Inc.	(319,409)	(388,713)	143,934	121,462	40,481
Earnings per common share:					
Net (loss) income per common share basic	$ (3.34)	$ (4.44)	$ 1.68	$ 1.59	$ 1.24
Net (loss) income per common share diluted	$ (3.34)	$ (4.44)	$ 1.67	$ 1.58	$ 1.20

(1) There are no operating results included for the Edge subsidiaries we acquired on December 31, 2009.

(2) Includes effects of hedging.

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

(4) Includes $754.3 million and $575.6 million of full cost ceiling test impairments for the years ended December 31, 2009 and 2008.

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	December 31,				
	2009	2008	2007	2006	2005
	(In thousands)				
Balance Sheet Data(1):					
Current Assets	$ 212,321	$ 374,953	$ 248,980	$ 306,018	$ 141,432
Current Liabilities	372,611	425,564	315,189	239,727	204,006
Working capital deficit	$ (160,290)	$ (50,611)	$ (66,209)	$ 66,291	$ (62,574)
Property and equipment, net	2,572,559	2,929,877	2,420,194	2,012,062	515,943
Total assets	2,867,205	3,392,793	3,083,635	2,680,153	665,536
Long-term debt, less current maturities	1,194,850	1,170,000	779,000	654,000	156,000
Stockholders equity	882,955	1,120,320	1,391,018	1,302,591	213,336

	Year Ended December 31,				
	2009	2008	2007	2006	2005
	(In thousands)				
Cash Flow Data(1):					
Net cash provided by operating activities	$ 577,667	$ 862,017	$ 536,114	$ 277,161	$ 165,444
Net cash used in investing activities	$ (747,108)	$ (1,264,784)	$ (643,780)	$ (561,390)	$ (247,799)
Net cash provided by financing activities	$ 175,109	$ 387,429	$ 116,676	$ 289,252	$ 84,370

(1) The fair market value of the Edge assets and liabilities we acquired on December 31, 2009 and cash flows from the transaction are included in the tables above.

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, the Gulf Coast and the Gulf of Mexico. During 2009, we produced approximately 126.5 Bcfe and our average daily production rate was 347 MMcfe. At December 31, 2009, we had 1.087 Tcfe of estimated proved reserves, of which approximately 56% were onshore (47% in the Permian Basin and 8% in the Gulf Coast), with the balance offshore (15% in the Gulf of Mexico deepwater and 29% on the Gulf of Mexico shelf); 53% were natural gas; and 47% were oil and natural gas liquids (NGLs). Approximately 66% of our estimated proved reserves were classified as proved developed.

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 mid-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 sustained recession or slowdown in economic activity could further 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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Securities Offering. On June 10, 2009, we sold and issued in concurrent underwritten offerings $300.0 million aggregate principal amount of our 113/4% senior notes due 2016, and 11.5 million shares of our common stock at a public offering price of $14.50 per share. We used aggregate proceeds from the concurrent offerings, before deducting estimated offering expenses but after deducting underwriters discounts and commissions, of approximately $446.2 million to repay debt under our bank credit facility.

Acquisitions On December 31, 2009, we acquired the reorganized Edge subsidiaries and operations. The material assets acquired consist primarily of (i) proved reserves estimated by Ryder Scott Company, L.P. as of December 31, 2009 of 100.5 Bcfe, of which approximately 75% are developed (consisting of 69% natural gas and 31% oil and NGLs), 81% are located in South Texas, and 44% are in the Flores/Bloomberg field in Starr County, Texas, (ii) approximately 60,000 net acres of undeveloped leasehold, primarily in Texas and New Mexico, and (iii) deferred tax assets of approximately $83.3 million, comprised of approximately $61.2 million in net operating loss carryforwards and $22.1 million in built-in losses from carryover tax basis in the properties. The effective date of the acquisition was June 30, 2009 and the purchase price was $260.0 million, less adjustments which resulted in a net purchase price as of December 31, 2009 of approximately $213.6 million, subject to final adjustments. We financed the net purchase price by borrowing under our secured revolving credit facility.

We recorded a gain on the acquisition of approximately $107.3 million. A gain on acquisition, or a bargain purchase, can happen in a business combination that is a forced sale in which the seller is acting under compulsion. Edge filed for federal bankruptcy protection in October 2009. In December 2009, we were the winning bidder in the bankruptcy auction for Edge s subsidiaries. In addition to Edge s distressed circumstances, the recent worldwide financial and credit crisis generally depressed financial and commodity markets and demand for energy assets, thereby further increasing the opportunity for a bargain purchase. A buyer is required to recognize in income from continuing operations changes in the amount of its recognizable deferred tax benefits resulting from a business combination when circumstances allow. We structured our purchase of Edge s reorganized subsidiaries as a stock acquisition to obtain the associated tax attributes that we expect to benefit us in future periods. Those attributes were recorded as deferred tax assets on an undiscounted basis in accordance with Accounting Standards Codification Topic 805 *Business Combinations* and contributed to the gain recognized on acquisition.

On December 19, 2008, we acquired additional working interests in our existing property, Atwater Valley Block 426 (Bass Lite), for approximately $30.6 million, increasing our working interest by 11.6% to 53.8%.

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. We operate substantially all of the assets. The purchase prices were $23.5 million for the February 2008 acquisition and $19.4 million for the December 2008 acquisition.

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. We paid $228.8 million for MGOM.

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Results of Operations

Year Ended December 31, 2009 compared to Year Ended December 31, 2008

Operating and Financial Results for the Year Ended December 31, 2009
Compared to the Year Ended December 31, 2008

	Year Ended December 31,		Increase	
	2009	2008	(Decrease)	% change
	(In thousands, except average sales price and unit costs)			
Summary Operating Information:				
Net Production:				
Natural gas (MMcf)	90,801	79,756	11,045	14%
Oil (MBbls)	4,472	4,881	(409)	(8)%
Natural gas liquids (MBbls)	1,478	1,558	(80)	(5)%
Total natural gas equivalent (MMcfe)	126,498	118,389	8,109	7%
Average daily production (MMcfe per day)	347	323	24	7%
Hedging Activities:				
Natural gas revenue gain (loss)	$ 187,857	$ (28,047)	$ 215,904	770%
Oil revenue gain (loss)	44,801	(72,762)	117,563	162%
Total hedging revenue gain (loss)	$ 232,658	$ (100,809)	$ 333,467	331%
Average Sales Prices:				
Natural gas (per Mcf) realized(1)	$ 6.08	$ 9.31	$ (3.23)	(35)%
Natural gas (per Mcf) unhedged	4.01	9.66	(5.65)	(58)%
Oil (per Bbl) realized(1)	70.59	86.02	(15.43)	(18)%
Oil (per Bbl) unhedged	60.57	100.93	(40.36)	(40)%
Natural gas liquids (per Bbl) realized(1)	33.10	55.02	(21.92)	(40)%
Natural gas liquids (per Bbl) unhedged	33.10	55.02	(21.92)	(40)%
Total natural gas equivalent ($/Mcfe) realized(1)	7.25	10.54	(3.29)	(31)%
Total natural gas equivalent ($/Mcfe) unhedged	5.41	11.39	(5.98)	(53)%
Summary of Financial Information:				
Natural gas revenue	$ 552,259	$ 742,370	$ (190,111)	(26)%
Oil revenue	315,642	419,878	(104,236)	(25)%
Natural gas liquids revenue	48,921	85,715	(36,794)	(43)%
Other revenues	26,119	52,544	(26,425)	(50)%
Lease operating expense	249,449	231,645	17,804	8%
Severance and ad valorem taxes	14,410	18,191	(3,781)	(21)%
Transportation expense	18,494	14,996	3,498	23%
General and administrative expense	79,960	60,613	19,347	32%
Depreciation, depletion and amortization	399,400	467,265	(67,865)	(15)%
Full cost ceiling test impairment	754,325	575,607	178,718	31%
Goodwill impairment		295,598	(295,598)	(100)%
Other property impairment		15,252	(15,252)	(100)%
Other miscellaneous expense	8,306	3,052	5,254	172%

Net interest expense	69,635	55,036	14,599	27%
Gain on acquisition	107,259		107,259	N/A
Loss before taxes	(543,779)	(436,748)	107,031	25%
Benefit for income taxes	(224,370)	(48,223)	176,147	365%
Net Loss	(319,409)	(388,525)	(69,116)	(18)%
Less: Net income attributable to noncontrolling interest		(188)	(188)	(100)%
Net Loss attributable to Mariner Energy, Inc.	$ (319,409)	$ (388,713)	$ (69,304)	(18)%
Average Unit Costs per Mcfe:				
Lease operating expense	$ 1.97	$ 1.96	$ 0.01	1%
Severance and ad valorem taxes	0.11	0.15	(0.04)	(27)%
Transportation expense	0.15	0.13	0.02	15%
General and administrative expense	0.63	0.51	0.12	24%
Depreciation, depletion and amortization	3.16	3.95	(.79)	(20)%

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

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Net Loss attributable to Mariner Energy, Inc. for 2009 was $319.4 million compared to $388.7 million for 2008. The decrease was primarily attributable to an $132.1 million decrease in impairments, a $67.9 million decrease in depreciation, depletion and amortization and a $176.1 million increase in income tax benefit. These were partially offset by a decrease in revenues of $357.6 million, a $107.3 million gain on acquisition and an increase in general and administrative expense of $19.3 million. Basic and diluted earnings per share for 2009 were $(3.34) for each measure compared to $(4.44) for each measure for 2008.

Net Production for 2009 was approximately 126.5 Bcfe, up 8.1 Bcfe or 6.8% from 118.4 Bcfe from 2008. Natural gas production for 2009 comprised approximately 72% of total production compared to approximately 67% for 2008.

Natural gas production for 2009 increased 14% to approximately 249 MMcf per day, compared to approximately 218 MMcf per day for 2008. Oil production for 2009 decreased 8% to approximately 12,251 barrels per day, compared to approximately 13,300 barrels per day for 2008. Natural gas liquids production for 2009 decreased 5% to approximately 4,049 barrels per day, as compared to approximately 4,257 barrels per day for 2008.

Period over period changes in our production were primarily attributable to the following:

- Increased production of 3.4 Bcfe, or 23%, from our onshore properties, primarily as a result of our drilling and development of existing acreage in the Permian Basin.

- Increased production of 12.4 Bcfe, or 31%, from our Gulf of Mexico deepwater properties, due primarily to Bass Lite located in Atwater Valley 426 (which contributed 9.9 Bcfe) and Geauxpher located in Garden Banks 462 (which contributed 13.0 Bcfe), partially offset by decreases at Pluto located in Mississippi Canyon 674 (which contributed 3.1 Bcfe) and Northwest Nansen located in East Breaks 602 (which contributed 6.0 Bcfe).

- Decreased production of 7.7 Bcfe, or 12%, from our Gulf of Mexico shelf properties as a result of normal depletion declines and production interruptions due to repairs on certain fields totaling 18.8 Bcfe, partially offset by increased production of 11.1 Bcfe at certain of our properties including High Island 116 (which contributed 3.4 Bcfe) and South Marsh Island 76 (which contributed 1.1 Bcfe).

Natural gas, oil and NGL revenues for 2009 decreased 27% to $916.8 million compared to $1,248.0 million for 2008 as a result of lower realized prices (approximately $416.6 million, net of the effect of hedging), which was partially offset by increased production (approximately $85.5 million).

During 2009, our revenues reflected a net recognized hedging gain of $232.7 million, comprised of $173.7 million in favorable cash settlements on our hedges, a $58.7 million reclassification on our liquidated swaps in 2009 and an unrealized gain of approximately $0.3 million related to the ineffective portion of open contracts that are not eligible for deferral in conformity with accounting for derivatives and hedging under GAAP due primarily to the basis differentials between the contract price and the indexed price at the point of sale. This compares to a net recognized hedging loss of approximately $100.8 million for 2008, 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 GAAP.

Our natural gas and oil average sales prices, and the effects of hedging activities on those prices, are listed in the table below. We did not conduct hedging activities related to NGL sales for the years ended December 31, 2009 and 2008.

	Realized	Unhedged	Hedging (Loss) Gain	% Change
Year Ended December 31, 2009:				
Natural gas (per Mcf)	$ 6.08	$ 4.01	$ 2.07	52%
Oil (per Bbl)	70.59	60.57	10.02	17%
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)%

Other revenues for 2009 decreased approximately $26.4 million to $26.1 million from $52.5 million for 2008 due primarily to the release of suspended revenue of $46.5 million in 2008 related to a potential MMS royalty liability and imputed rent income of $4.3 million in 2008 from the lease of office property acquired in January 2008, partially offset by a $16.6 million arbitration award related to a consummated acquisition and $7.4 million in third party gas sales on commodities purchased to satisfy our pipeline transportation commitments (discussed in other miscellaneous expense).

Lease operating expense (LOE) for 2009 increased approximately $17.8 million to $249.4 million from $231.6 million for 2008, primarily due to increased costs of $16.5 million attributable to processing fees primarily related to Atwater 426 (Bass Lite) and Garden Banks 462 (Geauxpher) not included in first three quarters of 2008 due to production on those fields commencing subsequent to that period, $19.9 million of repairs on certain properties (including $2.6 million on South Marsh Island 11 and $1.9 million on Eugene Island 292) and $11.8 million for repairs related to Hurricane Ike. These increases were offset by a decrease of $24.0 million in the retrospective contingent OIL insurance premium.

Severance and ad valorem tax for 2009 decreased approximately $3.8 million to $14.4 million from $18.2 million for 2008 due to lower production taxes of $4.5 million, partially offset by increased ad valorem taxes of $0.7 million.

Transportation expense for 2009 increased approximately $3.5 million to $18.5 million from $15.0 million for 2008 due primarily to increased expense at Bass Lite located in Atwater 426.

General and administrative expense (G&A) for 2009 increased approximately $19.4 million to $80.0 million from $60.6 million for 2008. The increase was due primarily to an increase in share-based compensation expense of approximately $8.1 million to $29.1 million from $21.0 million for 2008. Of this increase, $4.6 million was attributable to long-term performance-based restricted stock awarded during 2008 and $3.5 million was due to shares of restricted stock grants made during 2009. 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. Professional fees and salaries and wages increased $11.4 million to $63.2 million from $51.8 million in 2008, mainly due to non-recurring projects and additional headcount. Capitalized G&A related to our acquisition, exploration and development activities increased $1.4 million to $21.2 million from $19.8 million in 2008.

Depreciation, depletion, and amortization expense (DD&A) for 2009 decreased approximately $67.9 million to $399.4 million ($3.16 per Mcfe) from $467.3 million ($3.95 Mcfe) for 2008. This decrease primarily resulted from the effects of ceiling test impairments in 2009 and 2008 of $704.7 million and $575.6 million, respectively, that substantially lowered the basis of our oil and gas properties. The change in the depletion rate resulted in a $107.4 million decrease in expense, partially offset by a $30.2 million increase in expense due to higher production for 2009 as compared to 2008.

Full cost ceiling test impairment of $49.6 million was recognized for the fourth quarter 2009 and $704.7 million was recognized for the first quarter 2009 as a result of the net capitalized cost of our proved

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oil and gas properties exceeding our ceiling limit. See Critical Accounting Policies and Estimates Full Cost Ceiling Test for more detail on this impairment.

Goodwill impairment of $295.6 million was recorded in the fourth quarter 2008 as a result of our annual impairment test. The goodwill was originally recorded in conjunction with a merger transaction consummated in March 2006 and the impairment was a result of weakened economic conditions and a decline in our stock price during the fourth quarter 2008. See Critical Accounting Policies and Estimates Goodwill for more detail on this impairment. The impairment reduced our net goodwill balance to $0 at December 31, 2008 and therefore no goodwill impairment was noted during 2009.

Other property impairment of $15.3 million was recognized as a result of our annual impairment assessment performed on our other property at December 31, 2008. See Critical Accounting Policies and Estimates Other Property for more detail on this impairment. No property impairment was recognized during 2009.

Other miscellaneous expense for 2009 increased approximately $5.3 million to $8.3 million from $3.0 million for 2008, due primarily to third party gas purchases of $6.8 million made to satisfy our pipeline transportation commitments, the sales of which are included in other miscellaneous income and increased ad valorem tax of $1.3 million, partially offset by a decrease in bad debt expense of approximately $2.9 million.

Net interest expense for 2009 increased approximately $14.6 million to $69.6 million from $55.0 million for 2008, due primarily to increased interest expense of $20.9 million as a result of our issuance of 113/4% senior notes due 2016, partially offset by decreased interest expense of $8.4 million on our credit facility as a result of lower interest rates and reduced borrowing in 2009 as compared to 2008 and increased capitalized interest of $5.1 million.

Gain on acquisition for 2009 of $107.3 was recognized as a result of our acquisition of the reorganized Edge subsidiaries and operations. See Note 2 Acquisitions in the Notes to the Consolidated Financial Statements in Part II, Item 8 of this Annual Report on Form 10-K for more detail.

Provision for income taxes for 2009 reflected an effective tax rate of 41.3% as compared to 11.0% for 2008. The increase in our effective tax rate was due primarily to the effect of a permanent non-deductible goodwill impairment of $295.6 million in 2008 and a permanent book-tax difference attributable to the non-taxable gain on acquisition of $107.3 million in 2009 discussed above. The 2009 effective tax rate excluding the non-taxable gain on acquisition would have been 34.5%. The 2008 effective tax rate excluding the goodwill impairment would have been 34.2%.

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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 and unit costs)			
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
Other miscellaneous expense	3,052	5,061	(2,009)	(40)%
Other income		5,811	(5,811)	(100)%
Net interest expense	55,036	53,262	1,774	3%

Income (Loss) before taxes	(436,748)	221,259	(658,007)	(297)%
(Benefit) Provision for income taxes	(48,223)	77,324	(125,547)	(162)%
Net Income (Loss)	(388,525)	143,935	(532,460)	(370)%
Less: Net income attributable to noncontrolling interest	(188)	(1)	(187)	(18,700)%
Net Income (Loss) attributable to Mariner Energy, Inc.	$ (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 attributable to Mariner Energy, Inc. 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 on our hedges and an unrealized loss of $2.0 million related to the ineffective portion of open contracts that are not eligible for deferral in conformity with accounting for derivatives and hedging under GAAP due primarily to the basis differentials between the contract price and the indexed price at the point of sale. 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 GAAP.

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 for 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.

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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 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 share-based compensation expense of approximately $10.1 million to $21.0 million from $10.9 million for 2007. This increase was due primarily 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 share-based 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 2008 as a result of our annual impairment test. The goodwill was originally recorded in conjunction with a merger transaction consummated in March 2006 and the impairment is a result of weakened economic conditions and a decline in our stock price during the fourth quarter 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 assessment 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 $1.7 million to $55.0 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.

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%.

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Liquidity and Capital Resources

Financial Condition

	Years Ended December 31, 2009	2008
	(In thousands, except ratios)	
Current ratio(1)	0.6 to 1	0.9 to 1
Working capital deficit(2)	$ (160,290)	$ (50,611)
Total debt	$ 1,194,850	$ 1,170,000
Operating cash flow(3)	$ 531,149	$ 885,887
Interest expense, net of capitalization	$ 70,134	$ 56,398
Fixed-charge coverage ratio(4)		
Total cash and marketable securities less debt(5)	$ (1,185,931)	$ (1,166,749)
Stockholders equity	$ 882,955	$ 1,120,320
Total liabilities to equity	2.25 to 1	2.03 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 cash provided by operating activities, plus or minus changes in operating assets and liabilities. See the following Reconciliation of Non-GAAP Measure: Operating Cash Flow.

(4) Fixed-charge coverage ratio is net earnings before taxes, net income attributable to noncontrolling interest and fixed charges divided by fixed charges (interest expense, net of capitalization plus amortization of discounts). Due to loss from operations in 2009 and 2008, the ratio coverage was less than 1:1. We would have needed to generate additional earnings of $558,440 and $446,399 respectively, to achieve a coverage of 1:1 for that period.

(5) Total cash and marketable securities less debt is cash and cash equivalents less long-term debt.

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, 2009	2008
	(In thousands)	
Net cash provided by operating activities (GAAP)	$ 577,667	$ 862,017

Changes in operating assets and liabilities	(46,518)	23,870
Operating cash flow (Non-GAAP)	$ 531,149	$ 885,887

2009 Cash Flows

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

	Years Ended December 31,		
	2009	2008	2007
	(In millions)		
Cash payments for interest, net of capitalized interest	$ 68.9	$ 62.2	$ 49.1
Net cash (refunds) payments for income taxes	(2.0)	2.9	$ 0.6

Net cash provided by operating activities decreased by $284.3 million to $577.7 million in 2009 from $862.0 million in 2008. The decrease was due primarily to lower revenue resulting from a decrease in realized prices of $416.6 million, partially offset by increased production of $85.5 million and a $16.6 million arbitration award.

As of December 31, 2009, we had a working capital deficit of $160.3 million, due in part to a non-cash current derivative liability and non-cash abandonment liability offset by a non-cash deferred income tax assets and $11.1 million related to the fair market value of current assets acquired in connection with the acquisition of the reorganized Edge subsidiaries and operations. In addition, working capital was 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 decreased by $517.7 million to $747.1 million in 2009 from $1,264.8 million in 2008 due primarily to decreased capital expenditures attributable to reduced activity in our drilling programs partially offset by the 2009 acquisition of the Edge subsidiaries and operations for approximately $213.6 million. Additionally, 2008 was impacted by the acquisition of MGOM, including approximately $15.0 million of mid-stream assets reflected in other property, and an increase in other property reflecting an investment of approximately $34.6 million in office property.

Net cash flows provided by financing activities decreased by $212.3 million to $175.1 million for 2009 from $387.4 million for 2008. The decrease was due primarily to $656.0 million net increased repayments under our bank credit facility, net of borrowings of approximately $213.6 million in December 2009 to finance the purchase of the Edge subsidiaries and operations and $223.5 million in January 2008 to finance the purchase of MGOM. The decrease was partially offset by $446.2 million of proceeds (before deducting estimated offering expenses but after deducting underwriters discounts and commissions) from debt and securities offerings in June 2009.

2009 Uses of Capital. Our primary uses of capital during 2009 were as follows:

- funding capital expenditures (excluding hurricane repairs and acquisitions) of approximately $524.3 million;
- funding hurricane repairs and hurricane-related abandonment expenditures (net of insurance recoveries) of approximately $6.6 million;
- paying interest of approximately $68.9 million;
- funding the purchase of the Edge subsidiaries and operations for approximately $213.6 million; and
- paying routine operating and administrative expenses.

2009 Capital Expenditures. The following table presents major components of our capital expenditures during 2009 compared to 2008.

	Year Ended December 31,	
	2009	2008
	(In thousands)	
Capital expenditures:		
Oil and natural gas development	$ 306,834	$ 588,456
Oil and natural gas property acquisitions	236,661	302,629
Oil and natural gas exploration	182,863	270,767

Leasehold acquisitions	21,942	152,567
Corporate expenditures and other	38,462	66,668
Total capital expenditures, net of proceeds from property conveyances	$ 786,762	$ 1,381,087

2009 Hurricane Expenditures. During the year ended 2009, we incurred approximately $81.7 million in hurricane expenditures resulting from Hurricanes Ike and Gustav, of which $22.7 million were repairs and $59.0 were capital expenditures. Since 2004, we have incurred approximately $321.5 million in hurricane

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expenditures from Hurricanes Ike, Gustav, Ivan, Katrina and Rita, of which $23.5 million were repairs, $193.9 were capital expenditures and $104.1 million were hurricane-related abandonment costs. Net of our deductible of $24.8 million and insurance proceeds received of $185.1 million, our insurance receivable at December 31, 2008 was $8.5 million, all of which 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.

2009 Sources of Capital. Our primary sources of capital during 2009 were as follows:

- cash flow from operations;
- net proceeds from sale of senior notes and common stock;
- 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, 2009, 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 $800.0 million scheduled to be redetermined in February 2010. The redetermination was pending on February 28, 2010, and we anticipate that it will occur in March 2010.

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.

We have used borrowings under the facility to facilitate acquisitions, and have used and may use borrowings under the facility for general corporate purposes. On June 10, 2009, we used aggregate proceeds from concurrent offerings of our 113/4% senior notes due 2016 and common stock, before deducting estimated offering expenses but after deducting underwriters discounts and commissions, of approximately $446.2 million to repay debt under our bank credit facility. These offerings are discussed further below. We funded our December 2009 acquisition of the Edge subsidiaries and operations by borrowing approximately $213.6 million under the credit facility.

As of December 31, 2009 and 2008, advances outstanding under the credit facility were $305.0 million and $570.0 million, respectively. In addition, as of December 31, 2009 four letters of credit were outstanding totaling $4.7 million, of which $4.2 million is required for plugging and abandonment obligations at certain of our offshore fields. As of December 31, 2009, after accounting for the $4.7 million of letters of credit, we had $490.3 million available to borrow under the credit facility.

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. At December 31, 2009, when borrowings at both LIBOR and prime-based rates were outstanding, the blended interest rate was 3.40% on all amounts borrowed. At December 31, 2008, the interest rate was 3.31%. During the year ended December 31, 2009, the commitment fee on unused capacity was 0.250% to 0.375% per annum through March 23, 2009 and 0.5% per annum thereafter.

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The credit facility subjects us to various restrictive covenants and contains 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:

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 these and other credit facility covenants as of December 31, 2009 when the ratio of consolidated current assets plus the unused borrowing base to consolidated current liabilities was 2.38 to 1.0 and the ratio of total debt to EBITDA was 1.99 to 1.0. 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.

Our payment and performance of 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 the assets of our subsidiaries, except our Canadian subsidiary, and guaranteed by our subsidiaries, other than Mariner Energy Resources, Inc. which is a co-borrower, and our Canadian subsidiary.

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

$300 million principal amount of 113/4% Senior Notes due 2016 issued in June 2009 (the 113/4% Notes);

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

$300 million principal amount of 71/2% Senior Notes due 2013 issued in April 2006 (the 71/2% Notes).

We sold and issued the 113/4% Notes on June 10, 2009 at 97.093% of principal amount, for an initial yield to maturity of 12.375%, in an underwritten offering registered under the Securities Act of 1933, as amended (1933 Act). Net offering proceeds, after deducting underwriters discounts and estimated offering expenses but before giving effect to the underwriters reimbursement of up to $0.5 million for offering expenses, were approximately $284.8 million. We used net offering proceeds (before deducting estimated offering expenses) to repay debt under our bank credit facility. The 113/4% Notes were issued under an Indenture among Mariner, the guarantors party thereto and Wells Fargo Bank, N.A., as trustee (the Base Indenture), as amended and supplemented by the First Supplemental Indenture thereto among the same parties, each dated as of June 10, 2009. Pursuant to the Base Indenture, we may issue multiple series of debt securities from time to time.

The Notes are governed by indentures that are substantially identical for each series. 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 our existing and future senior unsecured indebtedness, and are effectively subordinated in right of payment to our senior secured indebtedness, including our obligations under our 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 our 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

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of the guarantor subsidiary and effectively subordinate to all existing and future secured indebtedness of the guarantor subsidiary, including its guarantees of indebtedness under our bank credit facility, to the extent of the collateral securing such indebtedness.

The 113/4% Notes mature on June 30, 2016 with interest payable on June 30 and December 30 of each year beginning December 30, 2009. The 8% Notes mature on May 15, 2017 with interest payable on May 15 and November 15 of each year. The 71/2% Notes mature on April 15, 2013 with interest payable on April 15 and October 15 of each year. There is no sinking fund for the Notes.

We may redeem the 113/4% Notes at any time before June 30, 2013, the 8% Notes at any time before May 15, 2012 and the 71/2% Notes at any time before April 15, 2010, 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, we 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:

113/4% Notes	**8% Notes**	**71/2% Notes**
June 30, 2013 at 105.875%	May 15, 2012 at 104.000%	April 15, 2010 at 103.750%
June 30, 2014 at 102.938%	May 15, 2013 at 102.667%	April 15, 2011 at 101.875%
June 30, 2015 and after at 100.000%	May 15, 2014 at 101.333%	April 15, 2012 and after at 100.000%
	May 15, 2015 and after at 100.000%	

In addition, before June 30, 2012, we may redeem up to 35% of the 113/4% Notes with the proceeds of equity offerings at a price equal to 111.750% of the principal amount of the 113/4% Notes redeemed plus accrued but unpaid interest. Before May 15, 2010, we 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 a change of control triggering event (as defined in each of the indentures governing the Notes) occurs, subject to certain exceptions, we must give holders of the Notes the opportunity to sell to us 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.

We and our restricted subsidiaries are subject to certain negative covenants under each of the indentures governing the Notes. The indentures limit the ability of us and each of our 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 our subsidiaries to us;
- 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 113/4% Notes offering were approximately $5.9 million, excluding discounts of $8.7 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. Costs associated with the 71/2% Notes offering were approximately $8.5 million, excluding discounts of $3.8 million.

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Common Stock Offering On June 10, 2009, we sold and issued 11.5 million shares of our common stock at a public offering price of $14.50 per share in an underwritten offering registered under the 1933 Act. The total sold includes 1.5 million shares issued upon full exercise of the underwriters overallotment option. Net offering proceeds, after deducting underwriters discounts and estimated offering expenses but before giving effect to the underwriters reimbursement of up to $0.5 million for offering expenses, were approximately $159.2 million. We used net offering proceeds (before deducting estimated offering expenses of approximately $0.5 million) to repay debt under our bank credit facility.

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 we may identify;
- paying routine operating and administrative expenses; and
- paying other commitments comprised largely of cash settlement of hedging obligations and debt service.

2010 Capital Expenditures.

We anticipate that our base operating capital expenditures for 2010 will be approximately $660.0 million (excluding hurricane-related expenditures and acquisitions), with significant potential for increase or decrease depending upon drilling success, acquisition opportunities and cash flow during the year. Approximately 67% of the base operating capital program is planned to be allocated to development activities, 26% 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 $44.5 million during 2010 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, 2009:

	Payments Due By Period (In thousands)				
	Total	**2010**	**2011-2012**	**2013-2014**	**Thereafter**
Debt obligations(1)	$ 1,205,000	$	$ 305,000	$ 300,000	$ 600,000
Interest obligations(2)	501,434	92,120	174,734	124,973	109,607
Operating leases	19,841	2,620	5,089	4,201	7,931
Abandonment liabilities	417,887	54,915	105,214	51,844	205,914
Seismic obligations	7,933	6,929	1,004		
Capital accrual obligations	140,941	140,941			
OIL Theoretical Withdrawal(3)	48,000	11,040	24,493	12,467	
Rig commitment	15,686	15,686			
Other liabilities(4)	103,547	103,547			

Total contractual cash commitments	$ 2,460,269	$ 427,798	$ 615,534	$ 493,485	$ 923,452

(1) As of December 31, 2009, we had incurred debt obligations under our bank credit facility and the Notes.

(2) Interest obligations represent interest due on the bank credit facility and the Notes per annum. Future interest obligations under our bank credit facility are uncertain, due to the variable interest rate on fluctuating balances. Based on a 3.40% weighted average interest rate on amounts outstanding under our

bank credit facility as of December 31, 2009, our cash payments for interest would be $10.4 million annually for 2010 through 2011 and $0.9 million in 2012.

(3) We have accrued approximately $48.0 million as of December 31, 2009, 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.

(4) Other liabilities include accrued LOE of $21.3 million, accrued liabilities of $15.2 million, gas balancing of $9.7 million, oil and gas payable of $38.8 million, accrued compensation of $12.0 million, other G&A of $3.3 million and other liabilities for $3.2 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.

Historically, we generally have tailored our operating capital program (exclusive of hurricane-related expenditures and acquisitions) within our projected operating cash flow so that our operating capital requirements were largely self-funding. In 2010, we anticipate that this program will exceed our projected operating cash flow due primarily to accelerated development of our long-lived, oily Permian Basin properties, and development of two deepwater discoveries and our unconventional resource portfolio. 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. We generally expect to fund future acquisitions on a case by case basis through a combination of bank debt and capital markets activities.

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

Our 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, 2009, four such letters of credit totaling $4.7 million were outstanding.

Fair Value Measurement

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.

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 accounting for fair value measurements and disclosures under GAAP.

During the twelve months ended December 31, 2009, we recorded a net liability for the decrease in the fair value of our derivative financial instruments of $161.5 million, principally due to the increase in natural gas and oil commodity prices above our swap prices. The decrease was comprised of a decrease in accumulated other comprehensive income of approximately $253.7 million, net of income taxes of $140.8 million, approximately $173.7 million of favorable cash hedging settlements and a $58.7 million gain on liquidated swaps during the period reflected in natural gas and oil revenues and an unrealized non-cash gain due to hedging ineffectiveness under GAAP of approximately $0.3 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 our 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 accounting for asset retirement and environmental obligations under GAAP, 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.

Full Cost Ceiling Test

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 natural gas and oil prices used to calculate the full cost ceiling limitation are the 12-month average prices, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, 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 accounting for derivative instruments and hedging activities under GAAP to hedge against the volatility of oil and natural gas prices. In accordance with SEC guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation. If net capitalized costs related to proved properties exceed the ceiling limit, the excess is impaired and recorded in the Consolidated Statements of Operations.

At December 31, 2009, the net capitalized cost of proved oil and gas properties exceeded the ceiling limit and we recorded an impairment of $49.6 million ($31.9 million, net of tax). The impairment would have been $159.2 million ($102.3 million, net of tax) if we had not used hedge adjusted prices for the volumes that were subject to hedges. This impairment is due primarily to a decline in the 12-month average oil and gas commodity prices used from January 1, 2009 through December 1, 2009 as compared to the spot prices utilized at March 31, 2009 and December 31, 2008 when we recorded non-cash ceiling test impairments of $704.7 million ($454.6 million, net of tax) and $575.6 million ($369.1 million, net of tax), respectively. The ceiling limit of our proved reserves was calculated at December 31, 2009 based upon 12-month average market prices of $3.87 per Mcf for gas and $61.18 per barrel for oil, adjusted for market differentials. At March 31, 2009 and December 31, 2008, the ceiling limit of our proved reserves was calculated based on quoted market spot prices of $3.63 and $5.71 per Mcf for gas and $49.65 and $44.61 per barrel for oil, respectively, adjusted for market differentials. At December 31, 2007 the ceiling limit exceeded the net capitalized costs of our proved oil and gas properties and no impairment was recorded. We may be required to recognize additional non-cash impairment charges in future reporting periods if the average 12-month market prices for oil and natural gas were to decline. At December 31, 2009, we had 48,697,000 MMbtus of natural gas and 3,815,500 Bbls of oil of future production hedged.

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

Costs associated with unproved properties and properties under development are excluded from the full cost amortization base until the properties have been evaluated. Additionally, the costs associated with seismic data, leasehold acreage, wells currently drilling and capitalized interest are also initially excluded from the amortization base. Unevaluated leasehold costs are either transferred to the amortization base once evaluation is complete or the lease expires on leasehold acreage. Until that time, the costs are subject to impairment, which is assessed quarterly. Leasehold costs are transferred to the amortization base to the extent a property is determined to be impaired. In addition, a portion of incurred (if not previously included in the amortization base) and future estimated development costs associated with qualifying major development projects may be temporarily excluded from the amortization base. To qualify, a project must require significant costs to ascertain the quantities of proved reserves attributable to the properties under development (e.g., the installation of an offshore production platform from which development wells are to be drilled). Incurred and estimated future development costs are allocated between completed and future work. Any temporarily excluded costs are included in the amortization base upon the earlier of when the associated reserves are determined to be proved or impairment is indicated.

The decision to withhold costs from the amortization base and the timing of the transfer of those costs into the amortization base involve a significant amount of judgment and may be subject to changes over time based on several factors, including our drilling plans, availability of capital, project economics and results of drilling on adjacent acreage. At December 31, 2009, we had a total of approximately $292.2 million of costs excluded from the amortization base of our full cost pools. Because the application of the full cost ceiling test at December 31, 2009 resulted in an excess of the carrying value of oil and gas properties over the ceiling limit, inclusion of some or all of our unevaluated property costs in the amortization base, without adding any associated reserves, would have resulted in a larger ceiling test impairment.

Future Development and Abandonment Costs

Future development costs include costs incurred to obtain access to proved reserves, such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of production platforms, gathering systems and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon their geographic location, type of production structure, water depth, reservoir depth and characteristics, market demand for equipment, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review these assumptions and estimates of future development and abandonment costs on an annual basis, or more frequently if an event occurs or circumstances change that would affect our assumptions and estimates.

DD&A

Our rate for recording DD&A is dependent upon estimates of our proved reserves, future development and abandonment costs and capital spending. If the estimates of proved reserves decline, the rate at which we record DD&A expense increases, reducing our net income. This decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields. The decline in proved reserve estimates may impact the outcome of the full cost ceiling test. In addition, increases in costs required to develop our reserves would increase the rate at which we record DD&A expense. We are unable to predict changes in future development costs as such costs are dependent on the success of our development program, as well as future economic conditions.

Abandonment Liability

In accordance with accounting for asset retirement and environmental obligations under GAAP, 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 adoption, we recorded an asset retirement obligation to reflect our legal obligations related to future plugging and abandonment of our oil and natural gas wells. The liability is accreted to its then present value each period, and the capitalized cost, net of salvage, 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.

Goodwill

We account for goodwill in accordance with GAAP which 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. At November 30, 2008, we had $295.6 million in goodwill. 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 2008, the carrying value of our reporting unit exceeded the fair value of our net assets 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 $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 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 a merger transaction consummated in March 2006. There was no remaining balance of goodwill in 2009 to assess for impairment.

Income Taxes

Our provision for taxes includes both state and federal taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP 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 carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Valuation allowances are established when necessary to reduce deferred tax assets to the amount more likely than not to be recovered.

We also account for uncertainty in income taxes recognized in the financial statements in accordance with GAAP 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 record a liability for the years ended December 31, 2009 and 2008.

Derivative Financial Instruments

We utilize 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 accounting for derivatives and hedging under GAAP. 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 our Consolidated Statements of Operations as the physical production hedged by the contracts is delivered. We present the fair value of our derivatives on a net basis in accordance with GAAP.

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.

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 us 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

We recognize oil and natural gas revenues when they are realized or realizable and earned. Revenues are considered realized or realizable and earned when persuasive evidence of an arrangement exists, delivery has occurred and title has transferred, the seller s price to the buyer is fixed or determinable and collectability is reasonably assured.

When we have an interest with other producers in properties from which natural gas is produced, we use the entitlement method to account for any imbalances. Imbalances occur when we sell more or less product than we are entitled to under our ownership percentage. Revenue is recognized only on the entitlement percentage of volumes sold. Any amount that we sell in excess of our entitlement is treated as a liability and is not recognized as revenue. Any amount of entitlement in excess of the amount we sell is recognized as revenue and a receivable is accrued.

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Share-Based Compensation Expense

We account for share-based compensation in accordance with the fair value recognition provisions of accounting for stock compensation under GAAP. Under those fair value recognition provisions, share-based compensation cost is measured at the grant date based on the calculated fair 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

In February 2010, the Financial Accounting Standards Board issued authoritative guidance which requires additional information to be disclosed principally in respect of Level 3 fair value measurements and transfers to and from Level 1 and Level 2 measurements. In addition, enhanced disclosure is required concerning inputs and valuation techniques used to determine Level 2 and Level 3 fair value measurements. The guidance is generally effective for interim and annual reporting periods beginning after December 15, 2009; however, the requirements to disclose separately purchases, sales, issuances, and settlements in the Level 3 reconciliation are effective for fiscal years beginning after December 15, 2010 (and for interim periods within such years). Early adoption is allowed. We are currently evaluating the potential impact of adoption.

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 2009 levels, a 10% increase in commodity prices from those as of December 31, 2009 would increase our cash flow by approximately $68.4 million for the year ended December 31, 2010.

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.

During 2009, the Company liquidated certain natural gas and crude oil fixed price swaps that previously had been designated as cash flow hedges for accounting purposes in respect of 10,205,560 MMBtu of natural gas and 977,000 Bbls of crude oil. The Company received $58.7 million in conjunction with these liquidations and recognized natural gas and oil revenues of $35.3 million and $23.4 million, respectively.

Derivative 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, 2009	2008	2007
		(In thousands)	
Cash Gain (Loss) on Settlements(1)	$ 173,684	$ (98,814)	$ 46,732
Gain (Loss) on Hedge Ineffectiveness(1)(2)	264	(1,995)	(1,655)
Reclassification of Liquidated Swaps(3)	58,710		
Total	$ 232,658	$ (100,809)	$ 45,077

(1) Designated as cash flow hedges pursuant to accounting for derivatives and hedging under GAAP.

(2) Unrealized loss recognized in natural gas revenue related to the ineffective portion of open contracts that are not eligible for deferral under GAAP due primarily to the basis differentials between the contract price and the indexed price at the point of sale.

(3) Natural gas and crude oil fixed price swaps liquidated in the first and third quarter 2009 that do not qualify for hedge accounting. These amounts include net losses of $2.8 million for the year ended December 31, 2009.

As of December 31, 2009, the Company had the following hedging contracts outstanding:

Fixed Price Swaps	Quantity	Weighted-Average Fixed Price	Fair Value Asset/(Liability)
		(In thousands)	
Natural Gas (MMbtus)			
January 1 December 31, 2010	22,619,000	$ 5.88	$ 2,239
January 1 December 31, 2011	13,650,000	$ 6.45	1,540
January 1 December 31, 2012	6,588,000	$ 6.62	497
January 1 December 31, 2013	5,840,000	$ 6.76	410
Crude Oil (Bbls)			
January 1 December 31, 2010	1,934,500	$ 67.48	(27,708)
January 1 December 31, 2011	978,100	$ 73.24	(11,309)
January 1 December 31, 2012	494,100	$ 80.77	(3,058)
January 1 December 31, 2013	408,800	$ 82.81	(2,195)
Total			$ (39,584)

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/(Liability)
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

We have reviewed the financial strength of our counterparties and believe the credit risk associated with these swaps 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, 2009, we expect to realize within the next 12 months approximately $25.5 million in net losses resulting from hedging activities currently recorded in accumulated other comprehensive income. The net hedging loss is expected to be realized as a decrease of $27.7 million to oil revenues and an increase of $2.2 million to natural gas revenues.

Interest Rate Market Risk

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. At December 31, 2009, the blended interest rate on our outstanding bank debt was 3.40%. If the balance of our bank debt at December 31, 2009 were to remain constant, a 10% increase in market interest rates would decrease our cash flow by approximately $1.0 million for the year ended December 31, 2010.

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, 2009. Management excluded from its evaluation the internal control over financial reporting of the subsidiaries of Edge Petroleum Corporation (the Edge Subsidiaries) which Mariner acquired on December 31, 2009. The total assets of the Edge Subsidiaries as of December 31, 2009 constituted approximately 11% of Mariner s total assets as of December 31, 2009. Deloitte & Touche LLP, Mariner s independent auditor for 2009, 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/	/s/
Scott D. Josey	Jesus G. Melendrez
Scott D. Josey,	Jesus G. Melendrez,
Chairman of the Board,	Senior Vice President, Chief Commercial Officer,
Chief Executive Officer and President	Acting Chief Financial Officer and Treasurer

Houston, Texas
March 1, 2010

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Mariner Energy, Inc. and subsidiaries (the Company) as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2009. We also have audited the Company s internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. As described in Management s Report on Internal Control over Financial Reporting (Report of Management), management excluded from its evaluation the internal control over financial reporting of the subsidiaries of Edge Petroleum Corporation (the Edge Subsidiaries) which the Company acquired on December 31, 2009. The total assets of the Edge Subsidiaries as of December 31, 2009 constituted approximately 11% of the total assets of the Company as of December 31, 2009. Accordingly, our audit did not include the internal control over financial reporting of the Edge Subsidiaries. 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 Report of Management. 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

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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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, 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, 2009, based on the criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As discussed in Note 1 to the consolidated financial statements, on December 31, 2009, the Company adopted Accounting Standards Update No. 2010-3, *Oil and Gas Reserve Estimation and Disclosures* and Accounting Standards Codification Topic 805, *Business Combinations* .

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 1, 2010

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MARINER ENERGY, INC.

CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	(In thousands, except share data)	
Current Assets:		
Cash and cash equivalents	$ 8,919	$ 3,251
Receivables, net of allowances of $3,408 and $3,868, respectively	148,725	219,920
Insurance receivables	8,452	13,123
Derivative financial instruments	2,239	121,929
Intangible assets	22,615	2,353
Prepaid expenses and other	11,667	14,377
Deferred income tax	9,704	
Total current assets	212,321	374,953
Property and Equipment:		
Proved oil and gas properties, full cost method	5,117,273	4,448,146
Unproved properties, not subject to amortization	292,237	201,121
Total oil and gas properties	5,409,510	4,649,267
Other property and equipment	55,695	53,115
Accumulated depreciation, depletion and amortization:		
Proved oil and gas properties	(2,884,411)	(1,767,028)
Other properties	(8,235)	(5,477)
Total accumulated depreciation, depletion and amortization	(2,892,646)	(1,772,505)
Total property and equipment, net	2,572,559	2,929,877
Insurance Receivables		22,132
Derivative Financial Instruments	902	
Deferred Income Tax	12,491	
Other Assets, net of amortization	68,932	65,831
TOTAL ASSETS	$ 2,867,205	$ 3,392,793
Current Liabilities:		
Accounts payable	$ 3,579	$ 3,837
Accrued liabilities	137,206	107,815
Accrued capital costs	140,941	195,833
Deferred income tax		23,148
Abandonment liability	54,915	82,364
Accrued interest	8,262	12,567
Derivative financial instruments	27,708	

Total current liabilities	372,611	425,564
Long-Term Liabilities:		
Abandonment liability	362,972	325,880
Deferred income tax		319,766
Derivative financial instruments	15,017	
Long-term debt	1,194,850	1,170,000
Other long-term liabilities	38,800	31,263
Total long-term liabilities	1,611,639	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, 2009 and December 31, 2008		
Common stock, $.0001 par value; 180,000,000 shares authorized, 101,806,825 shares issued and outstanding at December 31, 2009; 180,000,000 shares authorized, 88,846,073 shares issued and outstanding at December 31, 2008	10	9
Additional paid-in-capital	1,257,526	1,071,347
Accumulated other comprehensive (loss) income	(25,955)	78,181
Accumulated deficit	(348,626)	(29,217)
Total stockholders equity	882,955	1,120,320
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 2,867,205	$ 3,392,793

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, 2009	2008	2007
	(In thousands except share data)		
Revenues:			
Natural gas	$ 552,259	$ 742,370	$ 534,537
Oil	315,642	419,878	284,405
Natural gas liquids	48,921	85,715	54,192
Other revenues	26,119	52,544	1,631
Total revenues	942,941	1,300,507	874,765
Costs and Expenses:			
Lease operating expense	249,449	231,645	152,627
Severance and ad valorem taxes	14,410	18,191	13,101
Transportation expense	18,494	14,996	8,794
General and administrative expense	79,960	60,613	42,151
Depreciation, depletion and amortization	399,400	467,265	384,321
Full cost ceiling test impairment	754,325	575,607	
Goodwill impairment		295,598	
Other property impairment		15,252	
Other miscellaneous expense	8,306	3,052	5,061
Total costs and expenses	1,524,344	1,682,219	606,055
OPERATING (LOSS) INCOME	(581,403)	(381,712)	268,710
Other Income/(Expenses):			
Interest income	499	1,362	1,403
Interest expense, net of amounts capitalized	(70,134)	(56,398)	(54,665)
Gain on acquisition	107,259		
Other income			5,811
(Loss) Income Before Taxes	(543,779)	(436,748)	221,259
Benefit (Provision) for Income Taxes	224,370	48,223	(77,324)
Net (Loss) Income	(319,409)	(388,525)	143,935
Less: Net income attributable to noncontrolling interest		(188)	(1)
NET (LOSS) INCOME ATTRIBUTABLE TO MARINER ENERGY, INC	$ (319,409)	$ (388,713)	$ 143,934
Net (Loss) Income per share attributable to Mariner Energy, Inc.:			

Basic	$ (3.34)	$ (4.44)	$ 1.68
Diluted	$ (3.34)	$ (4.44)	$ 1.67
Weighted average shares outstanding:			
Basic	95,607,445	87,491,385	85,645,199
Diluted	95,607,445	87,491,385	86,125,811

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 CHANGES IN STOCKHOLDERS EQUITY

	Common Stock	Stock Amount	Additional Paid-In-Capital	Accumulated Other Comprehensive Income/ (Loss)	Accumulated Retained Earnings (Deficit) (In thousands)	Total Mariner Energy, Inc. Stockholders Equity	Noncontrolling Interest	Total Stockholders Equity
alance at December 31, 006	86,376	$ 9	$ 1,043,923	$ 43,097	$ 215,562	$ 1,302,591	$	$ 1,302,591
ommon shares issued stricted stock	906							
reasury stock bought and ncelled on same day	(72)		(1,553)			(1,553)		(1,553
orfeiture of restricted ock	(45)		(907)			(907)		(907
hare-based compensation			11,797			11,797		11,797
tock options exercised	64		829			829		829
omprehensive income oss):								
et income					143,934	143,934	1	143,935
hange in fair value of erivative hedging struments net of income xes of ($52,385)				(94,935)		(94,935)		(94,935
edge settlements classified to income net f income taxes of $15,815				29,262		29,262		29,262
otal comprehensive (loss) come				(65,673)	143,934	78,261	1	78,262
alance at December 31, 007	87,229	$ 9	$ 1,054,089	$ (22,576)	$ 359,496	$ 1,391,018	$ 1	$ 1,391,019
ommon shares issued stricted stock	1,734							
reasury stock bought and ncelled on same day	(144)		(4,313)			(4,313)		(4,313
orfeiture of restricted ock	(29)							
hare-based compensation			20,829			20,829		20,829

tock options exercised	56		742			742		742
omprehensive income oss):								
et loss					(388,713)	(388,713)	188	(388,525
hange in fair value of erivative hedging struments net of income xes of $91,316				165,675		165,675		165,675
edge settlements classified to income net f income taxes of 35,891)				(64,918)		(64,918)		(64,918
otal comprehensive come (loss)				100,757	(388,713)	(287,956)	188	(287,768
urchase of noncontrolling terest							(189)	(189
alance at December 31, 008	88,846	$ 9	$ 1,071,347	$ 78,181	$ (29,217)	$ 1,120,320	$	$ 1,120,320
ommon shares issued uity offering	11,500	1	159,734			159,735		159,735
ommon shares issued stricted stock	1,742							
reasury stock bought and ancelled on same day	(216)		(2,666)			(2,666)		(2,666
orfeiture of restricted ock	(66)							
hare-based compensation			29,097			29,097		29,097
tock options exercised	1		14			14		14
omprehensive loss:								
et loss					(319,409)	(319,409)		(319,409
hange in fair value of erivative hedging struments net of income xes of ($140,778)				(253,658)		(253,658)		(253,658
edge settlements classified to income net f income taxes of $83,129				149,529		149,529		149,529
oreign currency anslation adjustment				(7)		(7)		(7
otal comprehensive loss				(104,136)	(319,409)	(423,545)		(423,545
alance at December 31, 009	101,807	$ 10	$ 1,257,526	$ (25,955)	$ (348,626)	$ 882,955	$	$ 882,955

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,		
	2009	2008	2007
		(In thousands)	
Operating Activities:			
Net (loss) income attributable to Mariner Energy, Inc.	$ (319,409)	$ (388,713)	$ 143,934
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Deferred income tax	(224,370)	(49,403)	77,324
Depreciation, depletion and amortization	399,400	467,265	384,321
Ineffectiveness of derivative instruments	(264)	1,995	1,655
Full cost ceiling test impairment	754,325	575,607	
Goodwill impairment		295,598	
Other property impairment		15,252	
Gain on acquisition	(107,259)		
Share-based compensation	25,434	21,017	10,890
Other	3,292	(52,731)	4,487
Changes in operating assets and liabilities:			
Receivables	79,950	(63,015)	(9,805)
Insurance receivables	26,803	47,839	(22,606)
Prepaid expenses and other	(23,777)	(1,853)	(23,406)
Accounts payable and accrued liabilities	(36,458)	(6,841)	(30,680)
Net cash provided by operating activities	577,667	862,017	536,114
Investing Activities:			
Acquisitions and additions to oil and gas properties	(530,949)	(1,220,067)	(674,740)
Acquisition of subsidiaries of Edge Petroleum Corporation	(213,553)		
Additions to other property and equipment	(2,606)	(49,717)	
Property conveyances			4,130
Restricted cash designated for investment		5,000	26,830
Net cash used in investing activities	(747,108)	(1,264,784)	(643,780)
Financing Activities:			
Credit facility borrowings	710,221	1,268,000	564,000
Credit facility repayments	(975,221)	(877,000)	(739,000)
Proceeds from note offering	291,279		300,000
Proceeds from equity offering	159,735		
Debt redetermination costs	(2,346)		
Repurchase of stock	(2,666)	(4,313)	(1,553)
Proceeds from exercise of stock options	14	742	829
Deferred offering costs	(5,907)		(6,600)

Partner distributions			(1,000)
Net cash provided by financing activities	175,109	387,429	116,676
Increase (Decrease) in Cash and Cash Equivalents	5,668	(15,338)	9,010
Cash and Cash Equivalents at Beginning of Period	3,251	18,589	9,579
Cash and Cash Equivalents at End of Period	$ 8,919	$ 3,251	$ 18,589

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

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MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
For the Years Ended December 31, 2009, 2008 and 2007

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, in the Gulf Coast and in the Gulf of Mexico, both shelf and deepwater. Unless otherwise indicated, references to Mariner , the Company , we , our , ours and us re Mariner Energy, Inc. and its subsidiaries collectively.

Principles of Consolidation The Consolidated Financial Statements include Mariner s accounts and those of its 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 year ended December 31, 2007. These amounts are presented herein as General and administrative expense for comparability to 2009 and 2008 presentation. 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.

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. The Company routinely assesses the recoverability of all material trade and other receivables to determine their collectability. The Company accrues 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 Company records receivables related to insurance recoveries when it believes the amount of the claim is realizable. The balance at December 31, 2009 relates to both repair and capital-related costs incurred to bring productive properties back to operating condition after sustaining significant damage from Hurricane Ike in 2008. Any difference in the amount recovered from the insurance provider and the insurance receivable will be recorded as an adjustment to oil and gas properties when the amount relates to capital costs incurred and to lease operating expense (LOE) when the amount relates to repair costs incurred.

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 accounting for asset retirement and environmental obligations under GAAP, 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. For the years ended

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)
For the Years Ended December 31, 2009, 2008 and 2007

December 31, 2009 and 2008, capitalized G&A totaled $21.2 million and $19.8 million, respectively, of which $3.6 million and $3.0 million, respectively related to non-cash share-based compensation.

Full Cost Ceiling Test 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. In accordance with Securities and Exchange Commission (SEC) rules, the natural gas and oil prices used to calculate the full cost ceiling limitation are the 12-month average prices, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. Prices are 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 GAAP to hedge against the volatility of oil and natural gas prices. In accordance with 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, 2009, the net capitalized cost of proved oil and gas properties exceeded the ceiling limit and Mariner recorded an impairment of $49.6 million ($31.9 million, net of tax). The impairment would have been $159.2 million ($102.3 million, net of tax) if the Company had not used hedge adjusted prices for the volumes that were subject to hedges. This impairment is due primarily to a decline in the 12-month average oil and gas commodity prices from January 1, 2009 through December 1, 2009 used as compared to the spot prices utilized at March 31, 2009 and December 31, 2008 when the Company recorded non-cash ceiling test impairments of $704.7 million ($454.6 million, net of tax) and $575.6 million ($369.1 million, net of tax), respectively. The ceiling limit of its proved reserves was calculated at December 31, 2009 based upon 12-month average market prices of $3.87 per Mcf for gas and $61.18 per barrel for oil, adjusted for market differentials. At March 31, 2009 and December 31, 2008, the ceiling limit of its proved reserves was calculated based on quoted market spot prices of $3.63 and $5.71 per Mcf for gas and $49.65 and $44.61 per barrel for oil, respectively, adjusted for market differentials. At December 31, 2007 the ceiling limit exceeded the net capitalized costs of the Company s proved oil and gas properties and no impairment was recorded. The Company may be required to recognize additional non-cash impairment charges in future reporting periods if average 12-month market prices for oil and natural gas were to decline. At December 31, 2009, the Company had 48,697,000 MMbtus of natural gas and 3,815,500 Bbls of oil of future production hedged.

Unproved Properties Costs associated with unproved properties and properties under development are excluded from the full cost amortization base until the properties have been evaluated. Additionally, the costs associated with seismic data, leasehold acreage, wells currently drilling and capitalized interest are also initially excluded from the amortization base. Unevaluated leasehold costs are either transferred to the amortization base once evaluation is complete or the lease expires on leasehold acreage. Until that time, the costs are subject to impairment which is assessed quarterly. Leasehold costs are transferred to the amortization base to the extent a property is determined to be impaired. In addition, a portion of incurred (if not previously included in the amortization base) and future estimated development costs associated with qualifying major development projects may be temporarily excluded from the amortization base. To qualify, a project must require significant costs to ascertain the quantities of proved reserves attributable to the properties under development (e.g., the installation of an offshore production platform from which development wells are to be drilled). Incurred and estimated future development costs are allocated between completed and future work. Any temporarily excluded costs are included in the amortization base upon the earlier of when the associated reserves are determined to be proved or impairment is indicated.

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The decision to withhold costs from the amortization base and the timing of the transfer of those costs into the amortization base involve a significant amount of judgment and may be subject to changes over time based on several factors, including the Company s drilling plans, availability of capital, project economics and results of drilling on adjacent acreage. At December 31, 2009, the Company had a total of approximately $292.2 million of costs excluded from the amortization base of the full cost pool. Because the application of the full cost ceiling test at December 31, 2009 resulted in an excess of the carrying value of oil and gas properties over the ceiling limit, inclusion of some or all of Mariner s unevaluated property costs in the amortization base, without adding any associated reserves, would have resulted in a larger ceiling test impairment.

Future Development and Abandonment Costs Future development costs include costs incurred to obtain access to proved reserves, such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of production platforms, gathering systems and related structures and restoration costs of land and seabed. The Company develops estimates of these costs for each of its properties based upon their geographic location, type of production structure, water depth, reservoir depth and characteristics, market demand for equipment, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. The Company reviews these assumptions and estimates of future development and abandonment costs on an annual basis, or more frequently if an event occurs or circumstances change that would affect the assumptions and estimates.

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 the Company s 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.

Depreciation, Depletion, and Amortization (DD&A) Mariner s rate for recording DD&A is dependent upon its estimate of proved reserves, future development and abandonment costs and capital spending. If the estimates of proved reserves decline, the rate at which the Company records DD&A expense increases, reducing its net income. This decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields. The decline in proved reserve estimates may impact the outcome of the full cost ceiling test. In addition, increases in costs required to develop the Company s reserves would increase the rate at which it records DD&A expense. Mariner is unable to predict changes in future development costs as such costs are dependent on the success of its development program, as well as future economic conditions.

Abandonment Liability In accordance with accounting for asset retirement and environmental obligations under GAAP, 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, 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 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 proved oil and gas properties.

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To estimate the fair value of an asset retirement obligation, the Company employs a present value technique, which reflects certain assumptions, including its 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.

	2009	2008
	(In thousands)	
Abandonment liability as of January 1	$ 408,244	$ 222,006
Liabilities incurred	23,842	46,514
Liabilities settled	(61,228)	(73,164)
Accretion expense	33,582	23,511
Revisions to previous estimates	7,992	144,957
Liabilities from assets acquired	5,455	44,420
Abandonment liability as of December 31(1)	$ 417,887	$ 408,244

(1) Includes $54.9 million and $82.4 million classified as a current accrued liability at December 31, 2009 and 2008.

Other Assets Other assets at December 31, 2009 and 2008 were primarily comprised of the following:

	2009	2008
	(In thousands)	
Oil and gas lease and well equipment held in inventory	$ 42,975	$ 41,051
Debt issuance costs	13,602	13,439
Prepaid compression and other	5,850	6,907
Long term deposits	5,501	3,767
Prepaid seismic	1,004	667
Other Assets, net of amortization(1)	$ 68,932	$ 65,831

(1) Net of accumulated amortization as of December 31, 2009 and 2008 of $10.4 million and $6.4 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 accounting for derivatives and hedging under GAAP. 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 GAAP.

Mariner is required to assess the effectiveness of all its 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

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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 the Company s open contracts at the end of each period. The fair values the Company reports in its 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 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 GAAP which 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. 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. At November 30, 2008, the Company had $295.6 million in goodwill. 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 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 $295.6 million of goodwill impairment in continuing operations as of December 31, 2008. As of December 31, 2009, Mariner had no remaining goodwill. As of December 31, 2008, Mariner had a net goodwill balance of zero consisting of $295.6 million in accumulated goodwill impairment losses.

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Income Taxes Mariner s provision for taxes includes both state and federal taxes. The Company records its federal income taxes in accordance with accounting for income taxes under GAAP 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 carryforwards 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.

The Company also accounts for uncertainty in income taxes recognized in the financial statements in accordance with GAAP by prescribing a 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 the Company s financial position, results of operations and cash flows. The Company does not have uncertain tax positions outstanding and, as such, did not record a liability for the years ended December 31, 2009 and 2008.

Revenue Recognition The Company recognizes oil and natural gas revenues when they are realized or realizable and earned. Revenues are considered realized or realizable and earned when persuasive evidence of an arrangement exists, delivery has occurred and title has transferred, the seller s price to the buyer is fixed or determinable and collectability is reasonably assured.

When the Company has an interest with other producers in properties from which natural gas is produced, the Company uses the entitlement method to account for any imbalances. Imbalances occur when the Company sells more or less product than it is entitled to under its ownership percentage. Revenue is recognized only on the entitlement percentage of volumes sold. Any amount that the Company sells in excess of its entitlement is treated as a liability and is not recognized as revenue. Any amount of entitlement in excess of the amount the Company sells is recognized as revenue and a receivable is accrued. 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. At December 31, 2009 and 2008, the Company had gas imbalance payables of $7.2 million and $12.5 million, respectively, and gas imbalance receivables of $7.0 million and $17.8 million, respectively.

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.

	Percentage of Total Revenues for Year Ended December 31,

Customer	**2009**	**2008**	**2007**
Williams Gas and affiliates	12%	5%	<1%
ChevronTexaco and affiliates	13%	16%	23%
Plains Marketing LP	11%	5%	7%
Shell	9%	10%	10%

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

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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 the Company s 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 the Company s general and administrative expenses that are directly attributable to its acquisition, exploration and development activities are capitalized as part of its full cost pool. The Company capitalized general and administrative costs related to its acquisition, exploration and development activities of approximately $21.2 million, $19.8 million and $14.0 million for the years ended December 31, 2009, 2008 and 2007, 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 $6.2 million, $13.5 million and $12.5 million for the years ended December 31, 2009, 2008 and 2007, 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, the Company 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) share-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.

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

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, 2009, 2008 and 2007:

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Net (Loss) Income	$ (319,409)	$ (388,525)	$ 143,935
Other comprehensive (loss) income, net of tax:			
Change in unrealized mark-to-market (losses) gains arising during period, net of tax	(253,658)	165,675	(94,935)
Derivative contracts settled and reclassified, net of tax	149,529	(64,918)	29,262
Foreign currency translation adjustment	(7)		
Change in accumulated other comprehensive (loss) income	(104,136)	100,757	(65,673)
Comprehensive (loss) income	(423,545)	(287,768)	78,262
Comprehensive income attributable to noncontrolling interest		188	1
Comprehensive (loss) income attributable to Mariner Energy, Inc.	$ (423,545)	$ (287,956)	$ 78,261

Recent Accounting Pronouncements In February 2010, the Financial Accounting Standards Board (FASB) issued authoritative guidance which requires additional information to be disclosed principally in respect of Level 3 fair value measurements and transfers to and from Level 1 and Level 2 measurements. In addition, enhanced disclosure is required concerning inputs and valuation techniques used to determine Level 2 and Level 3 fair value measurements. The guidance is generally effective for interim and annual reporting periods beginning after December 15, 2009; however, the requirements to disclose separately purchases, sales, issuances, and settlements in the Level 3 reconciliation are effective for fiscal years beginning after December 15, 2010 (and for interim periods within such years). Early adoption is allowed. The Company is currently evaluating the potential impact of adoption.

In January 2010, FASB issued Accounting Standards Update (ASU) 2010-03, Oil and Gas Reserve Estimation and Disclosures , to provide consistency with the new SEC rules. The ASU amends existing standards to align the reserves calculation and disclosure requirements under US GAAP with the requirements in the SEC rules. The Company adopted the new standards effective December 31, 2009. The new standards are applied prospectively as a change in estimate.

In June 2009, the FASB issued authoritative guidance on the hierarchy of GAAP which established only two levels of GAAP, authoritative and non-authoritative. The FASB Accounting Standards Codification (ASC or the Codification) will become the source of authoritative, nongovernmental GAAP, except for rules and interpretive releases of the SEC, which are sources of authoritative GAAP for SEC registrants upon adoption. All other non-grandfathered, non-SEC accounting literature not included in the Codification will

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become non-authoritative. The Codification is effective for financial statements for interim or annual reporting periods ending after September 15, 2009. The Company began using the new guidelines prescribed by the Codification when referring to GAAP in respect of the third quarter ending September 30, 2009. As the Codification was not intended to change or alter existing GAAP, it did not have any impact on the Company s consolidated financial position, cash flows or results of operations.

In May 2009, the FASB issued authoritative guidance which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued and sets forth (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. The guidance is effective for periods beginning after June 15, 2009. The adoption did not have a material impact on the Company s financial position, cash flows or results of operations.

In April 2009, the FASB amended existing authoritative guidance to provide guidelines for making fair value measurements more consistent with other authoritative guidance, enhance consistency in financial reporting by increasing the frequency of fair value disclosures and create greater clarity and consistency in accounting for and presenting impairment losses on securities. This guidance is effective for interim and annual periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. The Company adopted the provisions for the period ending March 31, 2009. The adoption did not have a material impact on the Company s financial position, cash flows or results of operations.

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. 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 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 are allowed to report, on an optional basis, probable and possible reserves;

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

Companies are 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 are 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 are 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.

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The adoption of this rule did have a material impact on the Company s results of operations and financial position as the average price used over the 12-month period to calculate the full cost ceiling test impairment and the Company s proved reserves was lower than the year-end spot prices that would have been used under the previous rule for oil and natural gas. The Company recorded a full cost ceiling test impairment of $49.6 million in the fourth quarter 2009 primarily as a result of using a 12-month average price. The adoption of this rule did not have a material impact on the Company s cash flows.

In December 2007, the FASB issued ASC 805 which establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any noncontrolling interest in the acquiree and the goodwill acquired. The guidance also establishes disclosure requirements which will enable users to evaluate the nature and financial effects of the business combination. The guidance was effective for fiscal years beginning after December 15, 2008; the Company adopted it beginning January 1, 2009. The adoption did impact the Company s accounting for business combinations in respect of the acquisition of the reorganized subsidiaries of Edge Petroleum Corporation (Edge) on December 31, 2009. See Note 2 Acquisitions for further details.

In December 2007, the FASB issued authoritative guidance 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 noncontrolling equity investments when a subsidiary is deconsolidated. The guidance also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. The guidance was effective for fiscal years beginning after December 15, 2008; the Company adopted it beginning January 1, 2009. The adoption did not have a material impact on the Company s results of operations, financial position or cash flows. However, it did impact the presentation and disclosure of noncontrolling (minority) interests in its consolidated financial statements.

In September 2006, the FASB issued authoritative guidance for fair value measurements, which defines fair value, establishes criteria to be considered when measuring fair value and expands disclosures about fair value measurements. The guidance was effective for all recurring measures of financial assets and financial liabilities (e.g. derivatives and investment securities) for fiscal years beginning after November 15, 2007. The Company adopted the provisions for all recurring measures of financial assets and liabilities on January 1, 2008. In February 2008, the FASB amended the authoritative guidance, which granted a one-year deferral of the effective date as it applied to nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value on a nonrecurring basis. Beginning January 1, 2009, Mariner applied the provisions to non-financial assets and liabilities. The adoption did not have a material impact on the Company s results of operations, financial position and cash flow.

Note 2. Acquisitions

Onshore Acquisition On December 31, 2009, Mariner acquired the reorganized subsidiaries and operations of Edge. The assets acquired consist primarily of (i) estimated proved reserves, (ii) undeveloped oil and gas property, primarily in Texas and New Mexico, (iii) exploration assets in the form of seismic data, and (iv) certain tax attributes of the acquired subsidiaries. The effective date of the acquisition was June 30, 2009 and the purchase price was

$260.0 million, less adjustments which resulted in a net purchase price as of December 31, 2009 of approximately $213.6 million, subject to final adjustments. Mariner financed the net purchase price by borrowing under its secured revolving credit facility.

The acquisition was accounted for under the purchase method of accounting in accordance with ASC 805 relating to Business Combinations . The purchase method requires the assets and liabilities acquired to be recorded at their fair values at the date of acquisition. No results of operations were recorded in the

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Consolidated Statement of Operations for the year-ended December 31, 2009. Transaction costs related to the acquisition were approximately $0.6 million, which were expensed as incurred and recorded as General and administrative expenses in the Consolidated Statement of Operations for the year ended December 31, 2009. The preliminary estimate of fair values as of December 31, 2009 is as follows (in thousands):

Proved oil and gas properties	$ 206,291
Unproved properties	36,695
Abandonment liability	(5,455)
	$ 237,531

In accordance with accounting for taxes in a business combinations under ASC 740, the acquired tax attributes were recorded based on the expected undiscounted amounts to be realized in future periods using the enacted tax rates. The preliminary estimate of associated deferred taxes recorded as of December 31, 2009 is as follows (in thousands):

Net operating losses	$ 61,182
Built-in losses from carryover tax basis in the properties	22,097
	$ 83,279

The following describes the procedures used to measure the amounts recognized at the acquisition date for the assets acquired and liabilities assumed in the acquisition. The Company applied a tax rate of 35%, which approximates the effective tax rate for the year ended December 31, 2009. Mariner also applied a weighted average cost of capital (WACC) that measures the returns required by both debt and equity investors, weighted by their respective contributions of capital. The WACC used to measure the acquired assets was 14%.

Proved properties The Company valued proved properties using a discounted cash flow method for the proved developed and undeveloped reserves acquired. Market strip prices were used for barrels of oil and MMBtus of natural gas as of December 31, 2009 for the first five years of the reserve life and then held constant for the remaining life of the reserves. These prices were adjusted for the Company s price differentials. Operating costs associated with those reserves were established based on the Company s current estimate of operating costs and fixed throughout the life of the reserves, including estimates of abandonment costs. Production and ad valorem taxes, as a percentage of revenue, were applied to the revenue value. Management estimated an additional risk associated with PUD volumes and risked those volumes at 80%.

Unproved properties This amount consists of leasehold acreage and unproved properties acquired, and proprietary seismic data which may be sold to third parties on a licensed basis. The Company valued the leasehold acreage using a market transaction approach of reviewing transactions in proximate locations as an indication of fair value from a market participant perspective. The market values for leasehold acreage were obtained for the respective areas of properties acquired and a per acre valuation was applied. The Company valued this seismic data using a replacement cost approach adjusted for technological obsolescence.

Abandonment Liability The Company used a present value technique to measure the fair value of the associated abandonment liability. The assumptions applied to calculate this amount included the same

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credit-adjusted risk-free interest rate and inflation rate used to account for other abandonment liabilities recorded, the associated estimated settlement date and current cost to settle the liability.

Deferred Tax Assets The Company measured the deferred tax assets based on the expected undiscounted amounts to be realized in future periods using the enacted tax rates. The tax attributes of the subsidiaries acquired consist of federal net operating loss carryforwards estimated at $174.8 million and built-in losses estimated at $87.1 million associated with the tax basis in the properties. The transaction to acquire the reorganized Edge subsidiaries was structured as a stock purchase to preserve the carryover tax attributes of the Edge subsidiaries.

After applying the respective methods discussed above to record the preliminary estimate of fair value associated with the assets and liabilities acquired as well as recording the tax attributes on an undiscounted basis in accordance with GAAP, the Company recorded a gain on the acquisition of approximately $107.3 million included in Gain on acquisition in the Consolidated Statement of Operations for the year ended December 31, 2009. The excess of the net assets acquired over the estimated purchase price consisted of approximately $24.0 million of property and approximately $83.3 million in deferred tax assets. The deferred tax assets are comprised of approximately $61.2 million in net operating loss carryforwards and $22.1 million in built-in losses from carryover tax basis in the properties.

A gain on acquisition, or a bargain purchase, can happen in a business combination that, among certain other situations, is a forced sale in which the seller is acting under compulsion. Edge filed for federal bankruptcy protection in October 2009. In December 2009, Mariner was the winning bidder in the bankruptcy auction for Edge s subsidiaries. In addition, a buyer is required to recognize in income from continuing operations changes in the amount of the recognizable deferred tax benefits resulting from a business combination when circumstances allow. The Company structured the purchase of Edge s reorganized subsidiaries as a stock acquisition to obtain the associated tax attributes that Mariner expects to benefit from in future periods. Those attributes were recorded as deferred tax assets and contributed to the gain recognized on acquisition.

Pro Forma Financial Information: The unaudited pro forma information set forth below gives effect to the acquisition of the reorganized Edge subsidiaries as if it had been consummated as of the beginning of the applicable period. The unaudited pro forma information has been derived from the historical Consolidated Financial Statements of the Company and of Edge. The unaudited pro forma information is for illustrative purposes only. The financial results may have been different had each of the acquired Edge subsidiaries been an independent company and had the companies always been combined. You should not rely on the unaudited 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,	
	2009	2008
	(Unaudited) (In thousands, except	

	per share amounts)	
Pro Forma:		
Revenue	$ 1,005,252	$ 1,461,783
Net (loss) income available to common stockholders	$ (437,622)	$ (660,322)
Basic (loss) earnings per share	$ (4.58)	$ (7.55)
Diluted (loss) earnings per share	$ (4.58)	$ (7.55)

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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 $228.8 million for the acquisition of MGOM.

Permian Basin Acquisitions On 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 were $23.5 million for the February 2008 acquisition and $19.4 million for the December 2008 acquisition.

Bass Lite On December 19, 2008, Mariner acquired additional working interests in its existing property, Atwater Valley Block 426 (Bass Lite), for approximately $30.6 million, increasing its working interest by 11.6% to 53.8%. Mariner internally estimated proved reserves attributable to the acquisition of approximately 17.6 Bcfe (100% natural gas).

Note 3. Long-Term Debt

As of December 31, 2009 and December 31, 2008 the Company s long-term debt was as follows:

	December 31, 2009	December 31, 2008
	(In thousands)	
Bank credit facility	$ 305,000	$ 570,000
113/4% Senior Notes, due June 30, 2016, net of discount	291,725	
8% Senior Notes, due May 15, 2017	300,000	300,000
71/2% Senior Notes, due April 15, 2013, net of discount	298,125	300,000
Total long-term debt	$ 1,194,850	$ 1,170,000

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, 2009, 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 $800.0 million scheduled to be redetermined in February 2010. The redetermination was pending on February 28, 2010, and Mariner anticipates that it will occur in March 2010.

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 borrowing base falls below the sum of the amount borrowed and uncollateralized letter of credit exposure, then to the extent of the deficit, the Company must prepay borrowings and cash collateralize letter of credit exposure, pledge additional unencumbered collateral, repay borrowings and cash collateralize letters of credit on an installment basis, or effect some combination of these actions.

The Company has used borrowings under the facility to facilitate acquisitions, and has used and may use borrowings under the facility for general corporate purposes. On June 10, 2009, the Company used aggregate proceeds from concurrent offerings of its 113/4% senior notes due 2016 and common stock, before deducting estimated offering expenses but after deducting underwriters discounts and commissions, of approximately $446.2 million to repay debt under its bank credit facility. These offerings are discussed further below in this

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Note 3 and in Note 4 Stockholders Equity. The Company funded its December 2009 acquisition of the reorganized Edge subsidiaries by borrowing approximately $213.6 million under the credit facility.

As of December 31, 2009 and 2008, advances outstanding under the credit facility were $305.0 million and $570.0 million, respectively. In addition, as of December 31, 2009 four letters of credit were outstanding totaling $4.7 million, of which $4.2 million is required for plugging and abandonment obligations at certain of the Company s offshore fields. As of December 31, 2009, after accounting for the $4.7 million of letters of credit, the Company had $490.3 million available to borrow under the credit facility.

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. At December 31, 2009, when borrowings at both LIBOR and prime-based rates were outstanding, the blended interest rate was 3.40% on all amounts borrowed. At December 31, 2008, the interest rate was 3.31%. During the year ended December 31, 2009, the commitment fee on unused capacity was 0.250% to 0.375% per annum through March 23, 2009 and 0.5% per annum thereafter. Commitment fees are included in Accrued interest in the Consolidated Balance Sheets accompanying these Notes.

The credit facility subjects the Company to various restrictive covenants and contains 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:

- 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 these covenants as of December 31, 2009 when the ratio of consolidated current assets plus the unused borrowing base to consolidated current liabilities was 2.38 to 1.0 and the ratio of total debt to EBITDA was 1.99 to 1.0.

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, except its Canadian subsidiary, and guaranteed by its subsidiaries, other than Mariner Energy Resources, Inc. which is a co-borrower, and its Canadian subsidiary.

Senior Notes On June 10, 2009, the Company sold and issued $300.0 million aggregate principal amount of its 113/4% Senior Notes due 2016 (the 113/4% Notes). The 113/4% Notes were sold at 97.093% of principal amount, for an initial yield to maturity of 12.375%, in an underwritten offering registered under the Securities Act of 1933, as amended (the 1933 Act). Net offering proceeds, after deducting underwriters discounts and estimated offering expenses but before giving effect to the underwriters reimbursement of up to $0.5 million for offering expenses, were approximately $284.8 million. The Company used net offering proceeds (before deducting estimated offering expenses) to repay debt under its bank credit facility. The 113/4% Notes were issued under an Indenture among the Company, the guarantors party thereto and Wells Fargo Bank, N.A., as trustee (the Base Indenture), as amended and supplemented by the First Supplemental Indenture thereto among the same parties, each dated as of June 10, 2009. Pursuant to the Base Indenture, the Company may issue multiple series of debt securities from time to time.

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). The 8% Notes were sold at par in an underwritten offering registered under the 1933 Act. Net offering proceeds, after deducting underwriters discounts and offering

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expenses, were approximately $293.4 million. The Company used the net offering proceeds to repay debt under its bank credit facility.

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 and together with the 113/4% Notes and the 8% Notes, the Notes) pursuant to Rule 144A under the 1933 Act. The 71/2% Notes were priced to yield 7.75% to maturity. 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 1933 Act.

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

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

The 113/4% Notes mature on June 30, 2016 with interest payable on June 30 and December 30 of each year beginning December 30, 2009. The 8% Notes mature on May 15, 2017 with interest payable on May 15 and November 15 of each year. The 71/2% Notes mature on April 15, 2013 with interest payable on April 15 and October 15 of each year. There is no sinking fund for the Notes.

The Company may redeem the 113/4% Notes at any time before June 30, 2013, the 8% Notes at any time before May 15, 2012 and the 71/2% Notes at any time before April 15, 2010, 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:

113/4% Notes	**8% Notes**	**71/2% Notes**
June 30, 2013 at 105.875%	May 15, 2012 at 104.000%	April 15, 2010 at 103.750%
June 30, 2014 at 102.938%	May 15, 2013 at 102.667%	April 15, 2011 at 101.875%
June 30, 2015 and after at 100.000%	May 15, 2014 at 101.333%	April 15, 2012 and after at 100.000%

May 15, 2015 and after at 100.000%

In addition, before June 30, 2012, the Company may redeem up to 35% of the 113/4% Notes with the proceeds of equity offerings at a price equal to 111.750% of the principal amount of the 113/4% Notes redeemed plus accrued but unpaid interest. 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 a change of control triggering event (as defined in each of the indentures governing the Notes) occurs, subject to certain exceptions, the Company must give holders of the Notes the opportunity to sell to the

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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 113/4% Notes offering were approximately $5.9 million, excluding discounts of $8.7 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. Costs associated with the 71/2% Notes offering were approximately $8.5 million, excluding discounts of $3.8 million.

Capitalized Interest For the period ended December 31, 2009 and 2008, capitalized interest totaled $14.7 million and $9.7 million, respectively.

Cash Interest Expense For the years ended December 31, 2009, 2008 and 2007 interest payments were $83.6 million, $62.2 million and $49.1 million, respectively.

Bank Debt Issuance Costs The Company capitalizes certain direct costs associated with the issuance of long-term debt. For the years ended December 31, 2009 and 2008 the Company capitalized $6.6 million and $2.3 million in debt issuance costs, included in Other Assets, net of amortization on the Consolidated Balance Sheet.

Note 4. Stockholders Equity

Common Stock Offering On June 10, 2009, the Company sold and issued 11.5 million shares of its common stock, par value $.0001 per share, at a public offering price of $14.50 per share in an underwritten offering registered under the 1933 Act. The total sold includes 1.5 million shares issued upon full exercise of the underwriters overallotment option. Net offering proceeds, after deducting underwriters discounts and estimated offering expenses but before giving effect to the underwriters reimbursement of up to $0.5 million for offering expenses, were approximately $159.2 million. The Company used net offering proceeds (before deducting estimated offering expenses of approximately $0.5 million) to repay debt under its bank credit facility.

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.

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The following table sets forth the computation of basic and diluted earnings per share for the years ended December 31, 2009, 2008 and 2007.

	2009			2008			2007		
	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 attributable to Mariner Energy, Inc. per share	$ (319,409)	95,607	$ (3.34)	$ (388,713)	87,491	$ (4.44)	$ 143,934	85,645	$ 1.68
Effect of dilutive securities:								481	(0.01)
Diluted net (loss) income attributable to Mariner Energy, Inc. per share	$ (319,409)	95,607	$ (3.34)	$ (388,713)	87,491	$ (4.44)	$ 143,934	86,126	$ 1.67

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 Mariner s net loss for the year ended December 31, 2009, approximately 623,000 shares issuable upon exercise of stock options and 2,044,000 unvested shares of restricted stock were excluded from the computation of diluted earnings per share because the effect was anti-dilutive. Due to the Company s 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, 2009, no preferred stock had been issued.

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

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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 fair value recognition provisions of accounting for stock compensation under GAAP. Under those fair value recognition provisions, 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.

Share-based compensation, including restricted stock and options under each of the Company s plans, for the years ended December 31, 2009, 2008 and 2007 was:

	Year Ended December 31		
	2009	2008	2007
	(In thousands)		

Share-based compensation included in:			
General and administrative expense	$ 25,434	$ 21,017	$ 10,890
Oil and natural gas properties under full cost method	3,663	2,956	
Total share-based compensation	$ 29,097	$ 23,973	$ 10,890

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Share-based compensation charged to earnings for the years ended December 31, 2009, 2008 and 2007 was:

	Year Ended December 31		
	2009	2008	2007
	(In thousands)		
Charged to earnings	$ 25,434	$ 21,017	$ 10,890
Tax benefit	(8,775)	(7,188)	(3,801)
	$ 16,659	$ 13,829	$ 7,089

Applicable Plans On May 11, 2009, the Company s stockholders approved the Mariner Energy, Inc. Third Amended and Restated Stock Incentive Plan (the Stock Incentive Plan). Restricted common stock and non-qualified stock options are outstanding under the Stock Incentive Plan pursuant to grants made since 2005. Non-qualified options to purchase the Company s common stock granted to certain employees in connection with a March 2006 merger transaction also are outstanding but are not governed by the Stock Incentive Plan (Rollover Options).

The Company s directors, employees and consultants are eligible to participate in the Stock Incentive Plan. Awards to participants may be made in the form of incentive stock options, non-qualified stock options or restricted stock. Effective May 11, 2009, the Stock Incentive Plan increased to 12,500,000 from 6,500,000 the maximum number of shares of the Company s common stock that can be issued to participants, and increased the number of shares that can be issued to any one employee to 5,700,000 from 2,850,000. Subject to the terms of the Stock Incentive Plan, the participants to whom awards are granted, the type or types of awards granted, the number of shares covered by each award, and the purchase price, conditions and other terms of each award are determined by the Company s board of directors or a committee thereof appointed by the board to administer the Plan (the committee).

Unless sooner terminated, no award may be granted under the Stock Incentive Plan after October 12, 2015. The Company s board of directors or the committee may amend, alter, suspend, discontinue, or terminate (collectively, change) the Stock Incentive Plan without the consent of any stockholder, participant, other holder or beneficiary of an award, or other person, except that:

without the approval of the Company s stockholders, no change can be made that would

(i) increase the total number of shares that may be issued under the Stock Incentive Plan, except as provided in the Stock Incentive Plan with respect to stock dividends or splits, or with respect to mergers, recapitalizations, reorganizations, spin-offs or other unusual transactions or events,

(ii) permit the exercise price of any outstanding option that is underwater to be reduced or for an underwater option to be cancelled and replaced with a new award,

(iii) include participants other than employees, non-employee directors and consultants, or

(iv) materially increase benefits accrued to participants under the Stock Incentive Plan; and

no change can materially adversely affect the rights of a participant under an award without the participant s written consent.

In addition, the Stock Incentive Plan may not be amended or terminated in any manner that would cause the Plan or any amounts or benefits payable under the Stock Incentive Plan to fail to comply with Section 409A of the Internal Revenue Code of 1986, as amended, to the extent applicable.

As of December 31, 2009, 7,070,824 shares remained available for future issuance to participants under the Stock Incentive Plan. During the year ended December 31, 2009, 713,694 shares of restricted stock vested

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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 216,469 shares in the year ended December 31, 2009 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 $2.7 million for the year ended December 31, 2009.

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 Restricted 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. Share-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 GAAP of the Company s restricted stock, including long-term performance based restricted stock, at December 31, 2009 and the changes during the year then ended:

	Equity Instruments (in thousands)	Weighted Average Fair Value	Aggregate Intrinsic Value (in thousands)	Weighted Average Remaining Contractual Life (Years)
Unvested at January 1, 2009	2,697,926	$ 28.22	$ 76,123	
Granted	1,742,007	11.25	19,594	
Vested	(713,694)	21.33	(15,221)	
Forfeited	(65,974)	26.70	(1,762)	
Unvested at December 31, 2009	3,660,265	$ 21.51	$ 78,734	6.07

The weighted average grant date fair value of restricted stock granted, including long-term performance based restricted stock, during the years ended December 31, 2008 and 2007 was $32.28 per share and $21.98 per share, respectively.

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