MARINER ENERGY INC
Form 10-K
April 02, 2007

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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, 2006**
	OR
o	**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number 1-32747

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

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

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

(713) 954-5500
(Registrant s telephone number, including area code)

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

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

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

None

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

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

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

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

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

Large accelerated filer o Accelerated filer o Non-accelerated filer þ

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, 2006 was approximately $1,488,130,039 based on the closing sale price of $18.37 per share as reported by the New York Stock Exchange. The number of shares of common stock of the registrant issued and outstanding on March 23, 2007 was 86,361,162.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of registrant s Proxy Statement relating to the Annual Meeting of Stockholders to be held May 9, 2007 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 futur 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

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materially from our expectations described in Items 1A and 7 and elsewhere in this annual report. These risks, contingencies and uncertainties relate to, among other matters, the following:

- the volatility of oil and natural gas prices;
- discovery, estimation, development and replacement of oil and natural gas reserves;
- cash flow, liquidity and financial position;
- business strategy;
- amount, nature and timing of capital expenditures, including future development costs;
- availability and terms of capital;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment;
- operating costs and other expenses;
- prospect development and property acquisitions;
- risks arising out of our hedging transactions;
- marketing of oil and natural gas;
- competition in the oil and natural gas industry;
- the impact of weather and the occurrence of natural events and natural disasters such as loop currents, hurricanes, fires, floods and other natural events, catastrophic events and natural disasters;
- governmental regulation of the oil and natural gas industry;
- environmental liabilities;
- developments in oil-producing and natural gas-producing countries;
- uninsured or underinsured losses in our oil and natural gas operations;
- risks related to our level of indebtedness; and
- our acquisition of Forest Oil Corporation s Gulf of Mexico operations including strategic plans, expectations and objectives for future operations, and the realization of expected benefits from the transaction.

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PART I

Unless the context otherwise requires or indicates, references to Mariner, we, our, ours, and us refer to Mariner Energy, Inc. and its subsidiaries collectively. Certain oil and natural gas industry terms used in this annual report are defined in the Glossary of Oil and Natural Gas Terms set forth in Items 1 and 2 of this annual report.

Items 1 and 2. *Business and Properties.*

General

Mariner Energy, Inc. is an independent oil and gas exploration, development, and production company with principal operations in three geographic areas:

- The shallow water, or shelf operations of the Gulf of Mexico, where we conduct operations in water depths up to 1,300 feet and operate projects at subsurface depths up to 20,000 total vertical feet. Conducting operations below subsurface depths of 15,000 feet entails more risk and expense than shallower operations due to geological and mechanical factors attendant to deeper projects. As a result, we categorize our shelf projects according to their targeted subsurface depth, referring to shallower projects at depths above 15,000 feet as conventional shelf projects and projects below 15,000 feet as deep shelf projects;

- The deepwater operations of the Gulf of Mexico, where we are an active operator of exploration and development projects in water depths up to 7,000 feet; and

- West Texas, where we are one of the most active drillers in the prolific Spraberry, Dean, and Wolfcamp trends in the Permian Basin.

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.

On March 2, 2006, we acquired Forest Oil Corporation s (Forest) entire Gulf of Mexico operations through the acquisition of its subsidiary Forest Energy Resources, Inc. Aggregate consideration for the acquisition included 50,637,010 shares of our common stock, which was distributed directly to the stockholders of Forest. Immediately after the acquisition, approximately 59% of our outstanding common stock was held by shareholders of Forest and approximately 41% of our common stock was held by our pre-acquisition stockholders. See Note 3, Acquisitions and Dispositions in Item 8 for more information regarding this transaction. In connection with the acquisition, our common stock began trading regular way on the New York Stock Exchange on March 3, 2006 under the symbol ME .

In 2006, we generated net income of $121.5 million on total revenues of $659.5 million. Production, revenues and net income increased significantly from results reported in 2005 primarily as a result of our acquisition of Forest s Gulf of Mexico operations. We produced approximately 80.5 Bcfe during 2006 and our average daily production rate was 221 MMcfe. Our average realized sales price per unit including the effects of hedging was $8.15/Mcfe. As of December 31, 2006, we had 715.5 Bcfe of estimated proved reserves, of which approximately 60% were natural gas and 40% were oil, natural gas liquids (NGLs) and condensate. Approximately 57% of our 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.

Balanced Growth Strategy

We are a growth company. Our multifaceted management team pursues a balanced growth strategy employing varying elements of exploration, development and acquisition activities to achieve a moderate-risk growth profile intended to produce predictable growth and attractive rates of return under most industry conditions.

Proven exploration prospect generation: Our explorationists have a distinguished track record in the Gulf of Mexico and have made several significant discoveries in the shelf, deep shelf and deepwater.

Our successful exploration program reduces our dependency on acquisitions over time, allows us to add value through the drill bit in a moderate-risk exploration program, and exposes us to high-impact projects that have the potential to create substantial value for our stockholders. Our reputation for generating high-quality exploration prospects also creates valuable partnering opportunities which allow us the option of participating in exploration projects developed by other operators. We expect to continue our exploration emphasis by identifying and developing high-impact conventional shelf, deep shelf and deepwater projects in the Gulf of Mexico.

Proactive operational management: Our development engineers have demonstrated their ability to effectively develop new fields, redevelop legacy fields, rejuvenate production, reduce unit costs, and add incremental reserves at attractive finding costs in both onshore and offshore fields.

Our successful exploitation program enhances the rate of returns of our projects, allows us to establish critical operational mass from which to expand in our focus areas, and generates a rich portfolio of incremental, lower-risk engineering/exploitation projects that counterbalance our exploration activities.

Opportunistic acquisition identification: Our management team has substantial experience identifying and executing a wide variety of tactical and strategic transactions intended to maximize shareholder value. In 2005 we added significant proved reserves primarily through acquisitions in West Texas, and subsequently in March 2006, through the acquisition of Forest s Gulf of Mexico operations. As part of our growth strategy, although not compelled to acquire, we expect to continue to acquire producing assets that have the potential to provide acceptable risk-adjusted rates of return and further increase our reserve base.

Actively managed risk profile: We seek to manage our risk profile by targeting a balanced exposure to development, exploitation and exploration opportunities. For example, we continue to develop and expand our West Texas asset base, which contributes stable cash flows and long-lived reserves to our portfolio as a counterbalance to our high-impact, high-production Gulf of Mexico assets. We often mitigate and diversify our risk in drilling projects by selling partial or entire interests in projects to industry partners or by entering into arrangements with partners in which they agree to pay a disproportionate share of drilling costs and compensate us for expenses incurred in prospect generation. We also enter into trades or farm-in transactions whereby we acquire interests in third-party generated prospects, thereby gaining exposure to a greater number of prospects. We expect to continue to pursue participation in these types of prospects in the future as a result of our larger scale and increased cash flow from the Forest Gulf of Mexico operations.

Our Competitive Strengths

We believe our core resources and strengths include:

Our high-quality assets with geographic and geological diversity. Our assets and operations are diversified among the Gulf of Mexico conventional shelf, deep shelf and deepwater and West Texas. Our asset

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portfolio provides a balanced exposure to long-lived West Texas reserves, Gulf of Mexico shelf growth opportunities and high-impact deepwater prospects.

Our large inventory of prospects. We believe we have significant potential for growth through the development of our existing asset base. The acquisition of Forest s Gulf of Mexico operations more than doubled our existing undeveloped acreage in the Gulf of Mexico to approximately 438,000 net acres and increased our total net leasehold acreage offshore to nearly one million acres. As of December 31, 2006, we have an inventory of approximately 812 drilling locations in West Texas, which we believe would require approximately five years to drill at our current rate.

Our successful track record of finding and developing oil and gas reserves. We have demonstrated our expertise in finding and developing additional proved reserves. In the three-year period ended December 31, 2006, we deployed approximately $2.2 billion of capital on acquisitions, exploration and development, while adding approximately 664 Bcfe of proved reserves and producing approximately 148 Bcfe.

Our depth of operating experience. Our veteran team of geoscientists, engineers, geologists and other technical professionals and landmen average more than 25 years of experience in the exploration and production business (including extensive experience in the Gulf of Mexico), much of it with major oil companies. The addition of experienced Forest personnel to Mariner s team of professionals has further enhanced our ability to generate and maintain an inventory of high-quality drillable prospects and to further develop and exploit our assets. Mariner s technical team has also proven to be an effective and efficient operator in West Texas, as evidenced by our successful production and reserve growth there in recent years.

Our technology and production techniques. Our team of geoscientists currently has access to regional seismic data from multiple, recent vintage 3-D seismic databases covering a significant portion of the Gulf of Mexico that we intend to continue to use to develop prospects on acreage being evaluated for leasing and to develop and further refine prospects on our expanded acreage position. We also have extensive experience and a successful track record in the use of subsea tieback technology to connect offshore wells to existing production facilities. This technology facilitates production from offshore properties without the necessity of fabrication and installation of platforms and top-side facilities that typically are more costly and require longer lead times. We believe the appropriate use of subsea tiebacks enables us to bring production online more quickly, makes target prospects more profitable and allows us to exploit reserves that may otherwise be considered non-commercial because of the high cost of infrastructure.

Properties

Our principal oil and gas properties are located in West Texas and the Gulf of Mexico. The Gulf of Mexico properties are primarily in federal waters.

West Texas Operations

Our West Texas operation has historically emphasized downspacing redevelopment activities in the prolific oil producing Aldwell Unit in the Permian basin. Since we began our West Texas redevelopment initiative in 2002, we have more than doubled our acreage position in the area and are targeting West Texas for continued expansion through our West Texas operations headquarters in Midland, Texas. Production from the region is primarily from the Spraberry, Wolfcamp and Dean formations at depths between 6,000 and 9,000 feet, and is heavily weighted toward long-lived oil and NGLs. We operate the majority of our production in West Texas, with working interests ranging from approximately 35% to 84%.

During 2006, our West Texas operation produced approximately 9.2 Bcfe (11% of our total production) and accounted for approximately 257 Bcfe of our proved reserves (36% of our total proved reserves) at year end.

Production was 69% oil and NGLs for 2006. We drilled 164 wells in the region during 2006 with a 100% success rate and plan to drill approximately 150 wells in the region during 2007. Based upon our current level of drilling activity, our drilling inventory in this area would sustain a five-year drilling program.

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Gulf of Mexico Deepwater Operations

Since its inception in 1996, Mariner has acquired and maintained a significant acreage position in the Deepwater Gulf of Mexico. We have successfully generated and operated deepwater exploration and development projects for more than 10 years. As a natural 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. At year-end 2006 we held interests in 70 deepwater blocks. Production in our Gulf of Mexico operations is largely from Pleistocene to lower Miocene aged formations, and varies between oil and gas depending on formation and age. 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 geologic understanding based on exploration success in these corridors gives us a competitive advantage in assessing prospects and vying for new leases.

During 2006, our deepwater operation produced approximately 20.5 Bcfe (25% of our total production) and accounted for approximately 130 Bcfe of our proved reserves (18% of our total proved reserves) at year end. Production was 71% natural gas. We drilled approximately six wells in the region during 2006 with an 83% success rate and plan to drill approximately six wells in the region during 2007.

Gulf of Mexico Shelf Operations

An incidental operator on the Gulf of Mexico shelf for a number of years, Mariner embraced the shallow water Gulf of Mexico shelf as a new operating area in 2006 through its acquisition of Forest s Gulf of Mexico operation. With the addition of Forest s Gulf of Mexico assets, Mariner has attained a critical mass on the shelf, owning interests in 225 blocks at year-end 2006. Due to Mariner s operational scale and substantial lease position on the shelf, Mariner is 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 Mariner s numerous stationary platform facilities, to high-impact, deep shelf wildcat prospects at depths approaching 20,000 total vertical feet.

During 2006, our Gulf of Mexico shelf operation produced approximately 50.8 Bcfe (64% of our total production) and accounted for approximately 328 Bcfe of our proved reserves (46% of our total proved reserves) at year end. Production was 76% natural gas. We drilled 20 wells in the region during 2006 with a 65% success rate and plan to drill approximately 20 in the region during 2007.

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Estimated Proved Reserves

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

	As of the Year Ended December, 31		
	2006	2005	2004
Estimated proved oil and natural gas reserves:			
Natural gas reserves (Bcf)	426.7	207.7	151.9
Oil (MMbbls)	48.1	21.7	14.3
Total proved oil and natural gas reserves (Bcfe)	715.5	337.6	237.5
Total proved developed reserves (Bcfe)	408.7	167.4	109.4
PV10 value ($ in millions):(1)			
Proved developed reserves	$ 1,198.9	$ 849.6	$ 335.4
Proved undeveloped reserves	362.6	432.2	332.6
Total PV10 value	$ 1,561.5	$ 1,281.8	$ 668.0
Standardized measure	$ 1,239.8	$ 906.6	$ 494.4
Prices used in calculating end of period proved reserve measures (excluding effects of hedging):			
Natural gas ($/MMBtu)	$ 5.62	$ 10.05	$ 6.15
Oil ($/bbl)	$ 61.06	$ 61.04	$ 43.45

The following table sets forth certain information with respect to our estimated proved reserves by geographic area as of December 31, 2006 based on estimates made in a reserve report prepared by Ryder Scott Company.

	Estimated Proved Reserve Quantities			PV10 Value(1) (In millions of dollars)			
Geographic Area	Oil (MMbbls)	Natural Gas (Bcf)	Total (Bcfe)	Developed	Undeveloped	Total	Standardized Measure (In millions)
West Texas	29.9	77.8	257.3	327.6	80.1	407.7	
Gulf of Mexico Deepwater	6.6	90.1	130.0	223.0	91.4	314.4	
Gulf of Mexico Shelf	11.6	258.8	328.2	648.3	191.1	839.4	

Total	48.1	426.7	715.5	1,198.9	362.6	1,561.5	$ 1,239.8
Proved Developed Reserves	26.8	247.8	408.7				

(1) PV10 Value (PV10) is a non-GAAP measure that differs from the corollary GAAP measure standardized measure of discounted future net cash flows in that PV10 is calculated without regard to future income taxes. Management believes that the presentation of PV10 values is relevant and useful to Mariner s investors because it presents the discounted future net cash flows attributable to our proved reserves independent of Mariner s individual income tax attributes, thereby isolating the intrinsic value of the estimated future cash flows attributable to our reserves. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. For these reasons, management uses, and believes the industry generally uses, the PV10 measure in evaluating and comparing acquisition candidates and assessing the potential return on investment related to investments in oil and 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 Mariner s presentation of the standardized measure of discounted future net cash flows, please see Standardized Measure of Discounted Future Net Cash Flows in the notes to the consolidated financial statements in this report. The table below provides a reconciliation of PV10 to the standardized measure of discounted future net cash flows.

	At December 31,		
Non-GAAP Reconciliation:	**2006**	**2005**	**2004**
		(In millions)	
Present value of estimated future net revenues (PV10)	$ 1,561.5	$ 1,281.8	$ 668.0
Future income taxes, discounted at 10%	(321.7)	(375.2)	(173.6)
Standardized measure of discounted future net cash flows	$ 1,239.8	$ 906.6	$ 494.4

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

Productive Wells

The following table sets forth the number of productive oil and gas wells in which we owned an interest at December 31, 2006 and December 31, 2005.

	Total Productive Wells at			
	December 31, 2006		**December 31, 2005**	
	Gross	**Net**	**Gross**	**Net**
Oil	864	436.0	492	271.3
Gas	257	143.0	37	10.7
Total	1,121	579.0	529	282.0

Acreage

The following table sets forth certain information with respect to actual developed and undeveloped acreage in which we own an interest as of December 31, 2006.

	At December 31, 2006			
	Developed Acres(*)		Undeveloped Acres	
	Gross	Net	Gross	Net
West Texas(*)	59,974	31,186	659	659
Gulf of Mexico Deepwater	91,980	36,026	299,520	209,502
Gulf of Mexico Shelf	792,300	375,904	350,583	227,834
Other Onshore	1,311	344	854	242
Total	945,565	443,460	651,616	438,237

(*) Includes 31,933 gross and 11,883 net acres committed under the Tamarack/Spraberry drill-to-earn program. Under this program, upon drilling and completing 150 wells, Mariner will obtain an approximate 35% working interest in all committed acreage. As of December 31, 2006, 109 of the 150 obligation wells had been drilled and completed.

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The following table sets forth that portion of Mariner s offshore undeveloped acreage as of December 31, 2006 that is subject to expiration during the three years ended December 31, 2009. The amount of onshore undeveloped acreage subject to expiration during the period presented is not material.

	Undeveloped Acreage Subject to Expiration in the Year Ended December 31,					
	2007		2008		2009	
	Gross	Net	Gross	Net	Gross	Net
Gulf of Mexico Deepwater	40,320	21,006	69,120	43,200	28,800	25,632
Gulf of Mexico Shelf	76,292	43,740	59,529	48,459	32,406	18,594
Total	116,612	64,746	128,649	91,659	61,206	44,226

Drilling Activity

Certain information with regard to our drilling activity during the years ended December 31, 2006, 2005 and 2004 is set forth below.

	Year Ended December 31,					
	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Producing	14	5.83	3	1.13	7	3.34
Dry	8	3.65	7	2.44	7	2.65
Total	22	9.48	10	3.57	14	5.99
Development wells:						
Producing	168	86.23	93	54.20	56	34.84
Dry					1	0.68
Total	168	86.23	93	54.20	57	35.52
Total wells:						
Producing	182	92.06	96	55.33	63	38.18
Dry	8	3.65	7	2.44	8	3.33
Total	190	95.71	103	57.77	71	41.51

Marketing and Customers

We market substantially all of the oil and natural gas production from the properties we operate as well as the properties operated by others where our interest is significant. The majority of our natural gas, oil and condensate production is sold to a variety of customers under short-term (less than 12 months) contracts at market-based prices. The following table lists customers accounting for more than 10% of our total revenues for the year indicated.

Customer	Percentage of Total Revenues for Year Ended December 31, 2006	2005	2004
BP Energy	14%	*	12%
Bridgeline Gas Distributing Company(**)		15%	27%
ChevronTexaco and affiliates(**)	23%	24%	18%
Louis Dreyfus Energy	10%	7%	*
Plains Marketing LP	11%	10%	

* Less than 1%

** Bridgeline Gas Distributing Company is an affiliate of ChevronTexaco

No activity in the period

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Title to Properties

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

We believe that we have satisfactory title to or rights in all of our producing properties. As is customary in the oil and natural gas industry, minimal investigation of title is made at the time of acquisition of undeveloped properties. Title investigation is made usually only before commencement of drilling operations. We believe that title issues are less likely to arise with offshore oil and 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 and larger 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, or RRA, signed into law on November 28, 1995, provides that all tracts in the Gulf of Mexico west of 87 degrees, 30 minutes West longitude in water more than 200 meters deep offered for bid within five years after the RRA was enacted will be relieved from normal federal royalties as follows:

Water Depth	Royalty Relief
200-400 meters	no royalty payable on the first 105 Bcfe produced
400-800 meters	no royalty payable on the first 315 Bcfe produced
800 meters or deeper	no royalty payable on the first 525 Bcfe produced

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

In addition to granting discretionary royalty relief, the MMS has elected to include automatic royalty relief provisions in many post-2000 leases, even though the RRA no longer applies. 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.

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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 gas produced in water depths of less than 200 meters and from deep gas accumulations of at least 15,000 feet of true vertical depth. Drilling of qualified wells must have started on or after March 26, 2003, and production must begin prior to January 26, 2009.

The impact of royalty relief can be significant. The current normal royalty due for leases in water depths of 400 meters or less is 16.7% of production, and the current normal royalty for leases in water depths greater than 400 meters is 12.5% of production. Royalty relief can substantially improve the economics of projects located in deepwater or in shallow water and involving deep gas.

Many of our MMS leases that are subject to royalty relief contain language suspending royalty relief if commodity prices exceed predetermined threshold levels for a given calendar year. As a result, royalty relief for a lease in a particular calendar year may be contingent upon average commodity prices staying below the threshold price specified for that year. In 2000, 2001, 2003, 2004 and 2005, natural gas prices exceeded the applicable price thresholds for a number of our projects, and for the affected leases we have been ordered to pay royalties for natural gas produced in those years. However, we have contested the authority of the MMS to include price thresholds in two of our post-Act leases, Black Widow and Garden Banks 367. We believe that post-Act leases are entitled to automatic royalty relief under the RRA regardless of commodity prices, and have pursued administrative and judicial remedies in this dispute with the MMS. For more information concerning the contested royalty payments and the MMS s demands. See Legal Proceedings under Item 3.

Regulation

Our operations are subject to extensive and continually changing regulation affecting the oil and natural gas industry. Many departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding on the oil and natural gas industry and its individual participants. The failure to comply with such rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability. We do not believe that we are affected in a significantly different manner by these regulations than are our competitors.

Transportation and Sale of Natural Gas

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

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

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

Regulation of Production

The production of oil and natural gas is subject to regulation under a wide range of state and federal statutes, rules, orders and regulations. State and federal statutes and regulations require permits for drilling operations, drilling bonds, and reports concerning operations. Texas and Louisiana, the states in which we own and operate properties, have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells, the spacing of wells, and the plugging and abandonment of wells and removal of related production equipment. Texas and Louisiana also restrict production to the market demand for oil and natural gas and several states have indicated interests in revising applicable regulations. These regulations can limit the amount of oil and natural gas we can produce from our wells, limit the number of wells, or limit the locations at which we can conduct drilling operations. Moreover, each state generally imposes a production or severance tax with respect to production and sale of crude oil, natural gas and gas liquids within its jurisdiction.

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

In 2000, the MMS issued a final rule that governs the calculation of royalties and the valuation of crude oil produced from federal leases. That rule amended the way that the MMS values crude oil produced from federal leases for determining royalties by eliminating posted prices as a measure of value and relying instead on arm s-length sales prices and spot market prices as indicators of value. On May 5, 2004, the MMS issued a final rule that changed certain components of its valuation procedures for the calculation of royalties owed for crude oil sales. The changes include changing the valuation basis for transactions not at arm s-length from spot to NYMEX prices adjusted for locality and quality differentials, and clarifying the treatment of transactions under a joint operating agreement. We believe that the changes will not have a material impact on our financial condition, liquidity or results of operations.

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.

Spills and Releases. The Comprehensive Environmental Response, Compensation, and Liability Act, or 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 or 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 U.S. 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

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the liability limit for offshore facilities is equal to all removal costs plus up to $75 million in other damages. These liability limits may not apply if a spill is caused by a party s gross negligence or willful misconduct, the spill resulted from violation of a federal safety, construction or operating regulation, or if a party fails to report a spill or to cooperate fully in a clean-up.

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

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

In furtherance of the Clean Water Act, the EPA promulgated the Spill Prevention, Control, and Countermeasure, or 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 requires compliance with the implementation of such amended plans by August 18, 2006 (on February 17, 2006, this compliance deadline was extended until October 31, 2007). We may be required to prepare SPCC plans for some of our facilities where a spill or release of oil could reach or impact jurisdictional waters of the U.S.

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

Congress is currently considering proposed legislation directed at reducing greenhouse gas emissions. It is not possible at this time to predict how legislation that may be enacted to address greenhouse gas emissions would impact the oil and gas exploration and production business. However, future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial position, results of operations and cash flows.

Waste Handling. The Resource Conservation and Recovery Act, or 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

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operator of a hazardous waste treatment, storage 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.

Safety. The Occupational Safety and Health Act, or OSHA, and other similar laws and regulations govern the protection of the health and safety of employees. The OSHA hazard communication standard, EPA community right-to-know regulations under Title III of CERCLA and analogous state statutes require that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governments and citizens. We believe that we are in substantial compliance with these requirements and with other applicable OSHA requirements.

Employees

As of December 31, 2006, we had 217 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

Hurricanes Katrina and Rita (2005)

In 2005, our operations were adversely affected by one of the most active and severe hurricane seasons in recorded history, resulting in substantial shut-in and delayed production, as well as necessitating extensive facility repairs and hurricane-related abandonment operations. Throughout 2006 we completed substantial facility repairs that successfully returned substantially all of our shut-in properties to production without the loss of material reserves.

As of December 31, 2006, we had incurred approximately $84.3 million in hurricane expenditures resulting from Hurricanes Katrina and Rita, of which $68.8 million were repairs and $15.5 million were hurricane-related abandonment costs. Substantially all of the costs incurred to date pertained to the Gulf of Mexico assets acquired from Forest. We estimate that we will incur additional hurricane-related abandonment costs of approximately $19.1 million during 2007, as well as additional facility repair costs that cannot be estimated at this time but which we do not believe will be material.

Under the terms of the acquisition from Forest, we are responsible for performing all facility repairs and hurricane-related abandonment operations on Forest s Gulf assets at our expense, and we are entitled to receive all related insurance proceeds under Forest s insurance policies at the time of the storms, subject to our meeting Forest s deductibles. At year end, we recorded an insurance receivable of approximately $56.3 million, net of deductibles, for facility repair costs in excess of insurance deductibles, inasmuch as we believe it is probable that these costs will be reimbursed under Forest s insurance policies. Moreover, we believe substantially all hurricane-related abandonment costs expended to date should also be covered under Forest s insurance.

Forest s primary insurance coverage for Katrina and Rita was provided through OIL Insurance, Ltd., an energy industry insurance cooperative. The terms of Forest s coverage included a deductible of $5 million per occurrence and a $1 billion industry-wide loss limit per occurrence. OIL has advised us that the aggregate claims resulting from each of Hurricanes Katrina and Rita are expected to exceed the $1 billion per occurrence

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loss limit and that our insurance recovery relating to Forest s Gulf of Mexico assets is therefore expected to be reduced pro rata with all other competing claims from the storms. To the extent insurance recovery under the primary OIL policy is reduced, Mariner believes the shortfall would be covered under Forest s commercial excess insurance coverage. Forest s excess coverage is not subject to an additional deductible and has a stated limit of $50 million. Mariner does not believe the hurricane related costs associated with Mariner s legacy properties (as opposed to those acquired from Forest) will exceed Mariner s $3.75 million deductible and we do not anticipate making a claim under our insurance.

Taking into account Forest s insurance coverage in effect at the time of Hurricanes Katrina and Rita, we currently estimate our unreimbursed losses from hurricane-related repairs and abandonments should not exceed $15 million. However, due to the magnitude of the storms and the complexity of the insurance claims being processed by the insurance industry, the timing of our ultimate insurance recovery cannot be ascertained. Although we expect to begin receiving insurance proceeds in the first half of 2007, we believe that full settlement of all hurricane-related insurance claims may take several quarters to complete. As a result, we expect to maintain a possibly significant insurance receivable for the indefinite future while we actively pursue settlement of our claims to minimize the impact to our working capital and liquidity. Any differences between our insurance recoveries and insurance receivables will be recorded as adjustments to our oil and gas properties.

Hurricane Ivan (2004)

In September 2004, we incurred damage from Hurricane Ivan that affected the Mississippi Canyon 66 (Ochre) and Mississippi Canyon 357 fields. Ochre production was shut-in until September 2006, when host platform repairs were completed and production recommenced at approximately the same net rate. Mississippi Canyon 357 production was shut-in until March 2005, when necessary repairs were completed and production recommenced; however, production was subsequently shut-in due to Hurricane Katrina and recommenced in the first quarter of 2007. As of December 31, 2006, we had incurred approximately $8.7 million of property damage related to Hurricane Ivan. To date, approximately $2.4 million has been recovered through insurance, with the balance of $4.7 million, net of deductible, recorded as insurance receivable, as we believe it is probable that these costs will be reimbursed under our insurance policies.

Current Insurance Against Hurricanes

Effective March 2, 2006, Mariner was accepted as a member of OIL Insurance, Ltd. As a result, all of our properties are now insured through OIL. The coverage contains a $5 million annual per-occurrence deductible for our assets and a $250 million per-occurrence loss limit. However, if a single event causes losses to OIL insured assets in excess of $500 million for Atlantic Named Windstorms (ANWS) or $750 million for non-ANWS events, amounts covered for such losses will be reduced on a pro rata basis among OIL members. Our current commercially underwritten insurance coverage for all Mariner assets is effective through June 1, 2007, and will pay out after OIL coverage has eroded. We have acquired additional windstorm/physical damage insurance covering all of Mariner s assets to supplement the existing OIL coverage. The coverage provides up to $51 million of annual loss coverage (with no additional deductible) if recoveries from OIL for insured losses are reduced by the OIL overall loss limit (i.e., if losses to OIL insured assets from a single event exceed $500 million for ANWS or $750 million for non-ANWS event).

We also have acquired additional limited business interruption insurance on most of our deepwater producing fields which becomes effective 60 days after a field is shut-in due to a covered event. The coverage varies by field and is limited to a maximum recovery resulting from windstorm damage of approximately $43 million (assuming all covered fields are shut-in for the full insurance term of 365 days).

Glossary of Oil and Natural Gas Terms

The following is a description of the meanings of some of the oil and gas industry terms used in this annual report. The definitions of proved developed reserves, proved reserves and proved undeveloped reserves

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have been abbreviated from the applicable definitions contained in Rule 4-10(a)(2-4) of Regulation S-X. The entire definitions of those terms can be viewed on the website at *http://www.sec.gov/about/forms/forms-x.pdf.*

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

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

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

Bcf. Billion cubic feet of natural gas.

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

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

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

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

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

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

Deepwater. Depths greater than 1,300 feet (the approximate depth of deepwater designation for royalty purposes by the U.S. Minerals Management Service).

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

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

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

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

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

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

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

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

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

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

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

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

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

Mcf. Thousand cubic feet of natural gas.

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

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

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

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

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

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

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.

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

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

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

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

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

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

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

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

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

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

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

Subsea trees. Wellhead equipment installed on the ocean floor.

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

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

Item 1A. *Risk Factors.*

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

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

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

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

Further, oil prices and natural gas prices do not necessarily fluctuate in direct relationship to each other. Because approximately 60% of our estimated proved reserves as of December 31, 2006 were natural gas reserves, our financial results are more sensitive to movements in natural gas prices. Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil and natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves and could have a material adverse effect on our financial condition and results of operations.

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

Estimating oil and natural gas reserves is complex and inherently imprecise. It requires interpretation of the available technical data and making many assumptions about future conditions, including price and other economic conditions. In preparing estimates we project production rates and timing of development expenditures. We also analyze the available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. This process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates, perhaps significantly. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control. At December 31, 2006, 43% of our estimated proved reserves were proved undeveloped.

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

In estimating future net revenues from 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 proved reserves referred to in this report is not necessarily the actual current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on fixed prices and costs as of the date of the estimate. Actual future prices and costs fluctuate over time and may differ materially from those used in the present value estimate. In addition, discounted future net cash flows are estimated assuming that royalties to the MMS, with respect to our affected offshore Gulf of Mexico properties will be paid or suspended for the life of the properties based upon oil and natural gas prices as of the date of the estimate. See Business and Properties Royalty Relief under Items 1 and 2 and Legal Proceedings under Item 3. Since actual future prices fluctuate over time, royalties may be required to be paid for various portions of the life of the properties and suspended for other portions of the life of the properties.

The timing of both the production and expenses from the development and production of oil and natural gas properties will affect both the timing of actual future net cash flows from our proved reserves and 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 the SEC s rules may not necessarily be the most appropriate discount factor. The effective interest rate at various times and the risks associated with our business or the oil and gas industry in general will affect the appropriateness of the 10% discount factor in arriving at an accurate net present value of future net cash flows.

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

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

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

Unless we conduct successful exploration and development activities or acquire properties containing proven reserves, our 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, especially since our acquisition of Forest s Gulf of Mexico operation. 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 proved reserves. Our future oil and natural gas reserves and production, and therefore our cash flow and income, are dependent on our success in economically finding or acquiring new reserves and efficiently developing our existing reserves.

Approximately 62% of our total estimated proved reserves are either developed non-producing or undeveloped and those reserves may not ultimately be produced or developed.

As of December 31, 2006, approximately 19% of our total estimated proved reserves were developed non-producing and approximately 43% were undeveloped. These reserves may not ultimately be developed or produced. Furthermore, not all of our undeveloped or developed non-producing reserves may be ultimately produced during the time periods we have planned, at the costs we have budgeted, or at all, which in turn may have a material adverse effect on our results of operations.

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

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

Our exploration and development activities may not be commercially successful.

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

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

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

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

Our decisions to purchase, explore, develop and exploit prospects or properties depend in part on data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often uncertain. Even when used and properly interpreted, 3-D seismic data and visualization techniques only assist geoscientists and geologists in identifying subsurface structures and hydrocarbon indicators. 3-D seismic data does not enable an interpreter to conclusively determine whether hydrocarbons are present or producible economically. In addition, the use of 3-D seismic and other advanced technologies require greater predrilling expenditures than other drilling strategies. Because of these factors, we could incur losses as a result of exploratory drilling expenditures. Poor results from exploration activities could have a material adverse effect on our future cash flows, ability to replace reserves and results of operations.

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

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

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

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

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

Offshore operations are subject to a variety of operating risks specific to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce or eliminate the funds available for exploration, development or leasehold acquisitions, or result in loss of equipment and properties.

Exploration for oil or natural gas in the deepwater Gulf of Mexico generally involves greater operational and financial risks than exploration on the shelf. Deepwater drilling generally requires more time and more advanced drilling technologies, involving a higher risk of technological failure and usually higher drilling costs. Our deepwater wells utilize subsea completion and tieback technology. As of December 31, 2006, we had 17 subsea wells. These wells were tied back to twelve host production facilities for production processing. An additional eight wells were then under development for tieback to five additional host production facilities. The installation of subsea production systems to tieback and operate subsea wells requires 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. Furthermore, deepwater operations generally lack the physical and oilfield service infrastructure present in the shallow waters of the Gulf of Mexico. As a result, a significant amount of time may elapse between a deepwater discovery and our marketing of the associated oil or natural gas, increasing both the financial and operational risk involved with these operations. Because of the lack and high cost of infrastructure, some reserve discoveries in the deepwater may never be produced economically.

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

We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in oil and natural gas prices and to achieve more predictable cash flow. These financial arrangements typically take the form of price swap contracts and costless collars. Hedging arrangements expose us to the risk of financial loss in some circumstances, including situations when the other party to the hedging contract defaults on its contract or production is less than expected. During periods of high commodity prices, hedging arrangements may limit significantly the extent to which we can realize financial gains from such higher prices. For example, our hedging arrangements reduced the benefit we received from increases in the prices for oil and natural gas by approximately $49 million in 2005, and increased the benefit we received by $33 million in 2006. 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.

Properties we acquire (including the Forest Gulf of Mexico properties we acquired in March 2006) may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities.

Properties we acquire, including the Forest Gulf of Mexico properties, may not produce as expected, may be in an unexpected condition and may subject us to increased costs and liabilities, including environmental liabilities. The reviews we conduct of acquired properties prior to acquisition are not capable of identifying all potential adverse conditions. Generally, it is not feasible to review in depth every individual property involved in each acquisition. Ordinarily, we will focus our review efforts on the higher value properties or properties with known adverse conditions and will sample the remainder. However, even a detailed review of records and properties may not necessarily reveal existing or potential problems or permit a buyer to become sufficiently familiar with the properties to assess fully their condition, any deficiencies, and development potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken.

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

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

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

Shortages 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. An increase in drilling activity in the U.S. or the Gulf of Mexico could increase the cost and decrease the availability of necessary drilling rigs, equipment, supplies and personnel.

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

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

Financial difficulties encountered by our farm-out partners 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 U.S. and the Gulf of Mexico are subject to extensive federal, state and local laws and regulations, including environmental and health and safety laws and regulations. We may be required to make large expenditures to comply with these environmental and other requirements. Matters subject to regulation include, among others, environmental assessment prior to development, discharge and emission permits for drilling and production operations, drilling bonds, and reports concerning operations and taxation.

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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 Business and Properties Regulation for more information on our regulatory and environmental matters.

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

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

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

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

Although we maintain insurance at levels which we believe are appropriate and consistent with industry practice, we are not fully insured against all risks, including drilling and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Losses and liabilities from uninsured and underinsured events and delay in the payment of insurance proceeds could have a material adverse effect on our financial condition and results of operations. The impact of Hurricanes Katrina and Rita have resulted in escalating insurance costs and less favorable coverage terms. In addition, we have not yet been able to determine the full extent of our insurance recovery and the net cost to us resulting from the hurricanes. See Business and Properties Insurance Matters under Items 1 and 2 for more information.

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Risks Relating to Our Acquisition of Forest s Gulf of Mexico Operations

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

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

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

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

If we fail to realize the anticipated benefits of the acquisition, our results of operations may be lower than we expect.

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

In order to preserve the tax-free treatment of the spin-off of Forest Energy Resources, we are required to abide by potentially significant restrictions which could limit our ability to undertake certain corporate actions that otherwise could be advantageous.

In connection with the acquisition we entered into a tax sharing agreement, which imposes ongoing restrictions on Forest and on us to ensure that applicable statutory requirements under the Internal Revenue Code of 1986, as amended, or the Code, and applicable Treasury regulations continue to be met so that the spin-off of Forest Energy Resources remains tax-free to Forest and its shareholders. As a result of these restrictions, our ability to engage in certain transactions may be limited for a period of two years following the spin-off.

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

Risks Relating to Financings

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

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

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

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 gas prices, economic and financial conditions in our industry and the global economy or competitive initiatives of our competitors, are beyond our control.

If we do not generate enough cash flow from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

- refinancing or restructuring our debt;
- selling assets;
- reducing or delaying capital investments; or
- seeking to raise additional capital.

However, we cannot assure that undertaking alternative financing plans, if necessary, would allow us to meet our debt obligations. Our inability to generate sufficient cash flow to satisfy our debt obligations or to obtain alternative financing, could materially and adversely affect our business, financial condition, results of operations and prospects.

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 by:

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

The breach of any of the covenants in the indenture or the bank credit facility could result in a default under the applicable agreement which would permit the applicable lenders or noteholders, as the case may be, to declare all amounts outstanding thereunder to be due and payable, together with accrued and unpaid interest. We may not have sufficient funds to make such payments. If we are unable to repay our debt out of cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We cannot assure that we will be able to generate sufficient cash flow to pay the interest on our debt or that 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, restrictions in our tax sharing agreement with Forest and the value of our assets and operating performance at the time of such offering or other financing. We cannot assure that any such offering, refinancing or sale of assets could be successfully completed.

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

None.

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

Each of Mariner and its subsidiary, Mariner Energy Resources, Inc., owns numerous properties in the Gulf of Mexico. Certain of these properties were leased from the MMS subject to the RRA. The RRA relieved lessees of the obligation to pay royalties on certain leases until a designated volume was produced. Two of these leases held by Mariner and one held by its subsidiary contained language that limited royalty relief if commodity prices exceeded predetermined levels. Since 2000, commodity prices have exceeded the predetermined levels, except in 2002. Mariner and its subsidiary believe the MMS did not have the authority to include commodity price threshold language in these leases and have withheld payment of royalties on the leases while disputing the MMS authority in two pending proceedings. Mariner has recorded a liability for 100% of the estimated exposure on its two leases, which at December 31, 2006 was $21.2 million, including interest. Various legal proceedings are pending concerning this potential liability and further proceedings may be initiated with respect to years not covered by the pending proceedings. In April 2005, the MMS denied Mariner s administrative appeal of the MMS April 2001 order asserting royalties were due because price thresholds had been exceeded. In October 2005, Mariner filed suit in the U.S. District Court for the Southern District of Texas seeking judicial review of the dismissal. Upon motion of the MMS, Mariner s lawsuit was dismissed on procedural grounds. In August 2006, Mariner filed an appeal of such dismissal. In May 2006, the MMS issued an order asserting price thresholds were exceeded in calendar years 2001, 2003 and 2004 and, accordingly, that royalties were due under such leases on oil and gas produced in those years. Mariner has filed and is pursuing an administrative appeal of that order. The MMS has not yet made demand for non-payment of royalties alleged to be due for calendar years subsequent to 2004 on the basis of price thresholds being exceeded.

The potential liability of Mariner Energy Resources, Inc. under its lease subject to the RRA containing such commodity price threshold language, including interest, is approximately $2.6 million as of December 31, 2006 and a reserve of that amount was recorded as of December 31, 2006. This potential liability relates to production from the lease commencing July 1, 2005, the effective date of Mariner s acquisition of Mariner Energy Resources, Inc.

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.

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Executive Officers of the Registrant

The following table sets forth the names, ages (as of March 15, 2007) 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	49	Chairman of the Board, Chief Executive Officer and President
Dalton F. Polasek	55	Chief Operating Officer
John H. Karnes	45	Senior Vice President, Chief Financial Officer and Treasurer
Jesus G. Melendrez	48	Senior Vice President Corporate Development
Mike C. van den Bold	44	Senior Vice President and Chief Exploration Officer
Teresa G. Bushman	57	Senior Vice President, General Counsel and Secretary
Judd A. Hansen	51	Senior Vice President Shelf and Onshore
Cory L. Loegering	51	Senior Vice President Deepwater
Richard A. Molohon	52	Vice President Reservoir Engineering

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

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

John H. Karnes Mr. Karnes was appointed Senior Vice President, Chief Financial Officer and Treasurer in October 2006. He served as Senior Vice President and Chief Financial Officer of The Houston Exploration Company from November 2002 through December 2005. He then served as Executive Vice President and Chief Financial Officer of Maxxam Inc. from April 2006 to July 2006, and Senior Vice President and Chief Financial Officer of CDX Gas, LLC from July 2006 to August 2006. Prior to joining Houston Exploration, Mr. Karnes was Vice President and General Counsel of Encore Acquisition Company, a NYSE-listed oil and gas producer, from January 2002 to November 2002, and Executive Vice President and Chief Financial Officer of CyberCash, Inc., a NASDAQ-listed internet payment software and services provider, during 2000 and 2001. He also served as Chief Operating Officer of CyberCash during the disposition of its operating divisions through a pre-packaged Chapter 11 bankruptcy proceeding in 2001. Earlier in his career, he served in senior management roles at several publicly-traded companies, including Snyder Oil Corporation and Apache Corporation, practiced law with the national law firm of Kirkland & Ellis, and was employed in various roles in the securities industry. Mr. Karnes has a J.D. from Southern Methodist University School of Law and a B.B.A. in Accounting from The University of Texas at Austin.

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

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

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

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

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

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

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

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PART II

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

Mariner common stock commenced regular way trading on March 3, 2006 on the New York Stock Exchange (NYSE) under the symbol ME. The following sets forth the range of high and low sales prices of Mariner common stock for the period March 3, 2006 through March 31, 2006 and for each quarterly period from April 1, 2006 through December 31, 2006 and for the current year to date:

Period Ended	**High**	**Low**
Period from March 3, 2006 to December 31, 2006		
Period Ended		
March 31, 2006	$ 21.00	$ 18.05
Quarter Ended		
June 30, 2006	$ 20.65	$ 14.81
September 30, 2006	19.68	15.94
December 31, 2006	21.36	17.68
Year Ending December 31, 2007		
First quarter (through March 23, 2007)	$ 20.55	$ 16.88

As of March 23, 2007 there were 717 holders of record of Mariner s issued and outstanding common stock; we believe that there are significantly more beneficial holders of our stock.

We currently intend to retain our earnings for the development of our business and do not expect to pay any cash dividends. We have not paid any cash dividends for the fiscal years 2004, 2005 or 2006. See Item 7, Liquidity and Capital Resources Bank Credit Facility and Item 8, Note 4 to Mariner s Financial Statements for a discussion of certain covenants in our bank credit facility and the indenture governing our senior unsecured notes, which restrict our ability to pay dividends.

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Performance Graph

Our common stock began regular way trading on the NYSE on March 3, 2006. The following graph compares the cumulative total shareholder 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 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**
Mariner Energy, Inc.	$ 100.00	$ 96.69
S&P 500 Index	$ 100.00	$ 110.18
Peer Group(2)	$ 100.00	$ 97.93

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

(2) Composed of the following seven (7) independent oil and gas exploration and production companies: ATP Oil & Gas Corporation, Bois d Arc Energy, Inc., Callon Petroleum Co., Energy Partners, Ltd., Plains Exploration & Production Company, Stone Energy Corporation, and W&T Offshore, Inc.

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

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Issuer Purchases of Equity Securities

Period	Total Number of Shares (or Units) Purchased	Average Price Paid per Share (or Unit)	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
October 1, 2006 to October 31, 2006(1)	326	$ 18.06		
November 1, 2006 to November 30, 2006(1)	42	19.86		
December 1, 2006 to December 31, 2006				
Total	368	18.96		

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

Item 6. ***Selected Financial Data.***

The following table shows Mariner s historical consolidated financial data as of and for the years ended December 31, 2006 and 2005, the period from January 1, 2004 through March 2, 2004, the period from March 3, 2004 through December 31, 2004, and each of the two years ended December 31, 2003 and 2002, respectively. The historical consolidated financial data as of and for the years ended December 31, 2006 and 2005, the period from January 1, 2004 through March 2, 2004 (Pre-2004 Merger), and the period from March 3, 2004 through December 31, 2004 (Post-2004 Merger), are derived from Mariner s audited financial statements included herein, and the historical consolidated financial data as of and for the years ended December 31, 2003 and 2002, are derived from Mariner s audited financial statements that are not 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 included in Item 8, 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.

On March 2, 2006, a subsidiary of Mariner completed a merger transaction with Forest Energy Resources, Inc. (the Forest Merger) pursuant to which Mariner effectively acquired Forest s Gulf of Mexico operations. Prior to the consummation of the Forest Merger, Forest transferred and contributed the assets and certain liabilities associated with its Gulf of Mexico operations to Forest Energy Resources. Immediately prior to the Forest Merger, Forest distributed all of the outstanding shares of Forest Energy Resources to Forest shareholders on a pro rata basis. Forest Energy Resources then merged with a newly-formed subsidiary of Mariner, became a new wholly-owned subsidiary of Mariner, and changed its name to Mariner Energy Resources, Inc. Immediately following the Forest Merger, approximately 59% of Mariner common stock was held by shareholders of Forest and approximately 41% of Mariner common stock was held by the pre-merger stockholders of Mariner. In the Forest Merger, Mariner issued 50,637,010 shares of common stock to the shareholders of Forest Energy Resources, Inc. Our acquisition of Forest Energy Resources added approximately 298 Bcfe of estimated proved reserves.

In March 2005, we completed a private placement of 16,350,000 shares of our common stock to qualified institutional buyers, non-U.S. persons and accredited investors, which generated approximately $229 million of gross proceeds, or approximately $211 million net of initial purchaser s discount, placement fee and offering expenses. Our former sole stockholder, MEI Acquisitions Holdings, LLC, also sold 15,102,500 shares of our common stock in the private placement. We used $166 million of the net proceeds from the sale of 12,750,000 shares of common stock to purchase and retire an equal number of shares of our common stock from our former sole stockholder. We used $38 million of the remaining net proceeds of approximately $44 million to repay borrowings drawn on our bank credit facility, and the balance to pay down $6 million of a $10 million promissory note payable to JEDI. See Note 1, Summary of Significant Accounting Policies contained in Item 8. As a result, after the private placement, an affiliate of MEI Acquisitions Holdings, LLC beneficially owned approximately 5.3% of our outstanding common stock.

On March 2, 2004, Mariner s former indirect parent, Mariner Energy LLC, merged with MEI Acquisitions, LLC, an affiliate of the private equity funds, Carlyle/Riverstone Global Energy and Power Fund II, L.P. and ACON Investments LLC (the Merger). Prior to the Merger, we were owned indirectly by JEDI, which was an indirect wholly-owned subsidiary of Enron Corp. The gross merger consideration was $271.1 million (which excludes $7.0 million of acquisition costs and other expenses paid directly by Mariner), $100 million of which was provided as equity by our new owners. As a result of the Merger, we are no longer affiliated with Enron Corp. See Note 1, Summary of Significant Accounting Policies contained in Item 8. The Merger did not result in a change in our strategic direction or operations. The financial information contained herein is presented in the style of Pre-2004 Merger activity (for all periods prior to March 2, 2004) and Post-2004 Merger activity (for the March 3, 2004 through December 31, 2004 period) to reflect the impact of the restatement of assets and liabilities to fair value as required by push-down purchase accounting at the March 2, 2004 merger date. The application of push-down accounting had no effect on our 2004 results of operations other than immaterial increases in depreciation, depletion and amortization expense and interest expense and a related decrease in our provision for income taxes. To facilitate management s discussion and analysis of financial condition and results of operations, we have presented 2004 financial information as Pre-2004 Merger (for the January 1 through March 2, 2004 period), Post-2004 Merger (for the March 3, 2004 through December 31, 2004 period) and Combined (for the full period from January 1 through December 31, 2004). The combined presentation does not reflect the adjustments to our statement of operations that would be reflected in a pro forma presentation. However, because such adjustments are not material, we believe that our combined presentation presents a fair presentation and facilitates an understanding of our results of operations.

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The financial information contained herein is presented in the style of Post-2004 Merger activity (for the March 3, 2004 through December 31, 2004 period and the years ended December 31, 2006 and December 31, 2005) and Pre-2004 Merger activity (for all periods prior to March 2, 2004) to reflect the impact of the restatement of assets and liabilities to fair value as required by push-down purchase accounting at the March 2, 2004 merger date.

	Post-2004 Merger			Pre-2004 Merger		
	Year Ended December 31,		Period from March 3, 2004 through December 31,	Period from January 1, 2004 through March 2,	Year Ended December 31,	
	2006	2005	2004	2004	2003	2002
	(in millions, except per share data)					
Statement of Operations Data:						
Total revenues(1)	$ 659.5	$ 199.7	$ 174.4	$ 39.8	$ 142.5	$ 158.2
Lease operating expense	91.6	24.9	19.3	3.5	23.2	25.2
Severance and ad valorem taxes						
Severance and ad valorem taxes	9.0	5.0	2.1	0.6	1.5	0.9
Transportation expenses	5.1	2.3	1.9	1.1	6.3	10.5
Depreciation, depletion and amortization	292.2	59.4	54.3	10.6	48.3	70.8
Impairment of production equipment held for use		1.8	1.0			
Derivative settlement					3.2	
Impairment of Enron related receivables						3.2
General and administrative expense	34.1	37.1	7.6	1.1	8.1	7.7
Operating income	227.5	69.2	88.2	22.9	51.9	39.9
Interest income	1.0	0.8	0.2	0.1	0.8	0.4
Interest expense, net of amounts capitalized	(39.7)	(8.2)	(6.0)		(7.0)	(10.3)
Income before taxes	188.8	61.8	82.4	23.0	45.7	30.0
Provision for income taxes	(67.3)	(21.3)	(28.8)	(8.1)	(9.4)	
Income before cumulative effect of change in accounting method net of tax effects	121.5	40.5	53.6	14.9	36.3	30.0
Cumulative effect of changes in accounting method					1.9	
Net income	$ 121.5	$ 40.5	$ 53.6	$ 14.9	$ 38.2	$ 30.0
Earnings per common share:						

Basic:						
Income before cumulative effect of changes in accounting method per common share	$ 1.59	$ 1.24	$ 1.80	$ 0.50	$ 1.22	$ 1.01
Cumulative effect of changes in accounting method					.07	
Net income per common share basic	$ 1.59	$ 1.24	$ 1.80	$ 0.50	$ 1.29	$ 1.01
Diluted:						
Income before cumulative effect of changes in accounting method per common share	$ 1.58	$ 1.20	$ 1.80	$ 0.50	$ 1.22	$ 1.01
Cumulative effect of changes in accounting method					.07	
Net income per common share diluted	$ 1.58	$ 1.20	$ 1.80	$ 0.50	$ 1.29	$ 1.01

(1) Includes effects of hedging.

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	Post-2004 Merger December 31,			Pre-2004 Merger December 31,	
	2006	**2005**	**2004**	**2003**	**2002**
			(in millions)		
Balance Sheet Data:(1)					
Property and equipment, net, full-cost method	$ 2,012.1	$ 515.9	$ 303.8	$ 207.9	$ 287.6
Total assets	2,680.2	665.5	376.0	312.1	360.2
Long-term debt, less current maturities	654.0	156.0	115.0		99.8
Stockholders equity	1,302.6	213.3	133.9	218.2	170.1
Working capital (deficit)(2)	41.1	(46.4)	(18.7)	38.3	(24.4)
Other Financial Data					
Ratio of earnings to fixed charges(3)	5.66	7.88	17.17	6.83	3.56

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

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

(3) For the purposes of determining the ratio of earnings to fixed charges, earnings consist of income before taxes, plus fixed charges, less capitalized interest, and fixed charges consist of interest expense (net of capitalized interest), plus capitalized interest, plus amortized discounts related to indebtedness. See Exhibit 12 to this annual report.

	Post-2004 Merger			Pre-2004 Merger		
	Year Ended December 31,		Period from March 3, 2004 through December 31,	Period from January 1, 2004 through March 2,	Year Ended December 31,	
	2006	**2005**	**2004**	**2004**	**2003**	**2002**
			(in millions)			
Cash Flow Data:						
Net cash provided by operating activities	$ 277.2	$ 165.4	$ 135.2	$ 20.3	$ 88.9	$ 60.3
Net cash (used) provided by investing activities	(561.4)	(247.8)	(133.0)	(15.3)	52.9	(53.8)
Net cash (used) provided by financing activities	289.3	84.4	(64.9)		(100.0)	

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

Overview

We are an independent oil and natural gas exploration, development and production company with principal operations in West Texas and the Gulf of Mexico. As of December 31, 2006, approximately 57% of our proved reserves were classified as proved developed, with approximately 36% of the reserves located in West Texas, 18% in the Gulf of Mexico deepwater, and 46% on the Gulf of Mexico shelf.

On March 2, 2004, Mariner s former indirect parent, Mariner Energy LLC, merged with MEI Acquisitions, LLC, an affiliate of the private equity funds, Carlyle/Riverstone Global Energy and Power Fund II, L.P. and ACON Investments LLC (the Merger). Prior to the Merger, we were owned indirectly by JEDI, which was an indirect wholly-owned subsidiary of Enron Corp. The gross merger consideration was $271.1 million (which excludes $7.0 million of acquisition costs and other expenses paid directly by Mariner), $100 million of which was provided as equity by our new owners. As a result of the merger, we are no longer affiliated with Enron Corp. See Note 1, Summary of Significant Accounting Policies contained in Item 8. The Merger did not result in a change in our strategic direction or operations. The financial information contained herein is presented in the style of Pre-2004 Merger activity (for all periods prior to March 2, 2004) and Post-2004 Merger activity (for the March 3, 2004 through December 31, 2004 period) to reflect the impact of the restatement of assets and liabilities to fair value as required by push-down purchase accounting at the March 2, 2004 merger date. The application of push-down accounting had no effect on our 2004 results of operations other than immaterial increases in depreciation, depletion and amortization expense and interest expense and a related decrease in our provision for income taxes. To facilitate management s discussion and analysis of financial condition and results of operations, we have presented 2004 financial information as Pre-2004 Merger (for the January 1 through March 2, 2004 period), Post-2004 Merger (for the March 3, 2004 through December 31, 2004 period) and Combined (for the full period from January 1 through December 31, 2004). The combined presentation does not reflect the adjustments to our statement of operations that would be reflected in a pro forma presentation. However, because such adjustments are not material, we believe that our combined presentation presents a fair presentation and facilitates an understanding of our results of operations.

In March 2005, we completed a private placement of 16,350,000 shares of our common stock to qualified institutional buyers, non-U.S. persons and accredited investors, which generated approximately $229 million of gross proceeds, or approximately $211 million net of initial purchaser s discount, placement fee and offering expenses. Our former sole stockholder, MEI Acquisitions Holdings, LLC, also sold 15,102,500 shares of our common stock in the private placement. We used $166 million of the net proceeds from the sale of 12,750,000 shares of common stock to purchase and retire an equal number of shares of our common stock from our former sole stockholder. We used $38 million of the remaining net proceeds of approximately $44 million to repay borrowings drawn on our bank credit facility, and the balance to pay down $6 million of a $10 million promissory note payable to JEDI. See Note 1, Summary of Significant Accounting Policies contained in Item 8. As a result, after the private placement, an affiliate of MEI Acquisitions Holdings, LLC beneficially owned approximately 5.3% of our outstanding common stock.

On March 2, 2006, a subsidiary of Mariner completed a merger transaction with Forest Energy Resources, Inc. (the Forest Merger) pursuant to which Mariner effectively acquired Forest s Gulf of Mexico operations. Prior to the consummation of the Forest Merger, Forest transferred and contributed the assets and certain liabilities associated with its Gulf of Mexico operations to Forest Energy Resources. Immediately prior to the Forest Merger, Forest distributed all of the outstanding shares of Forest Energy Resources to Forest shareholders on a pro rata basis. Forest Energy Resources then merged with a newly-formed subsidiary of Mariner, became a new wholly-owned subsidiary of Mariner, and changed its name to Mariner Energy Resources, Inc. Immediately following the Forest Merger, approximately 59% of Mariner common stock was held by shareholders of Forest and approximately 41% of Mariner common stock was held by the pre-merger stockholders of Mariner. In the Forest Merger, Mariner issued 50,637,010 shares of common stock to the shareholders of Forest Energy Resources, Inc. Our acquisition of Forest Energy Resources added approximately 298 Bcfe of estimated proved reserves.

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas and our ability to find, develop and acquire oil and gas reserves that are economically recoverable while controlling and reducing costs. The energy markets have historically been very volatile. Commodity prices are currently at or near historical highs and may fluctuate 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.

Critical Accounting Policies and Estimates

Our discussion and analysis of Mariner s financial condition and results of operations are based upon financial statements that have been prepared in accordance with Generally Accepted Accounting Principles in the United States of America (GAAP) . The preparation of these financial statements requires us to make

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estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in Note 1 to our financial statements. We analyze our estimates, including those related to oil and gas revenues, oil and gas properties, fair value of derivative instruments, goodwill, asset retirement obligations, income taxes and contingencies and litigation, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our financial statements:

Oil and Gas Properties

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. Amortization of oil and gas properties is provided using the unit-of-production method based on estimated proved oil and gas reserves. No gains or losses are recognized upon the sale or disposition of oil and gas properties unless the sale or disposition represents a significant quantity of oil and gas reserves, which would have a significant impact on the depreciation, depletion and amortization rate.

At the end of each quarter, a full-cost ceiling limitation calculation is made whereby net capitalized costs related to proved and unproved properties less related deferred income taxes may not exceed an amount equal to the present value discounted at ten percent of estimated future net revenues from proved reserves plus the lower of cost or fair value of unproved properties less estimated future production and development costs and related income tax expense. The full-cost ceiling limitation is calculated using natural gas and oil prices in effect as of the balance sheet date and adjusted for basis or location differential, held constant over the life of the reserves. We use derivative financial instruments that qualify for cash flow hedge accounting under SFAS 133, Accounting for Derivative Instruments and Hedging Activities, to hedge against the volatility of natural gas prices and, in accordance with SEC guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation. If net capitalized costs related to proved properties less related deferred income taxes were to exceed this limit, the excess would be charged to expense. Additional guidance was provided in Staff Accounting Bulletin No. 47, Topic 12(D)(c)(3), primarily regarding the use of cash flow hedges, asset retirement obligations, and the effect of subsequent events on the ceiling test calculation. Once incurred, a write-down is not reversible at a later date.

Proved Reserves

Our most significant financial estimates are based on estimates of proved natural gas and oil reserves. Estimates of proved reserves are key components 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, and the accuracy of reserve estimates is a function of the quality and quantity of available data. Our reserves are fully engineered on an annual basis by Ryder Scott Company.

Unproved Properties

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

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed in the acquisition. We account for goodwill in accordance with Statement of Financial Accounting Standards (SFAS) No. 142, Goodwill and Other Intangible Assets . SFAS No. 142 requires an annual impairment assessment and a more frequent assessment if certain events occur that indicate impairment may have occurred. We performed the goodwill impairment assessment in the fourth quarter of 2006. The initial impairment assessment compares Mariner s net book value to its estimated fair value. If impairment is indicated, then Mariner is required to make estimates of the fair value of goodwill. The estimated fair value of goodwill is based on many factors, including future net cash flows of estimated proved reserves as well as the success of future exploration and development of unproved reserves. If the carrying amount of goodwill exceeds the estimated fair value, then a measurement of the loss is performed with any excess charged to expense. To date, no impairment to goodwill has been recorded.

Income Taxes

Our provision for taxes includes both state and federal taxes. Mariner records its federal income taxes using an asset and liability approach which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax bases of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and 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 apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from these estimates, which could impact our financial position, results of operations and cash flows.

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

Abandonment Liability

SFAS No. 143, Accounting for Asset Retirement Obligations, addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 was adopted on January 1, 2003. SFAS No. 143 requires that the fair value of a liability for an asset s retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized.

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.

Hedging Program

We use derivative instruments in the form of natural gas and crude oil price swap agreements and costless collar arrangements in order to manage price risk associated with future crude oil and natural gas production and fixed-price crude oil and natural gas purchase and sale commitments. Such agreements are accounted for as hedges using the deferral method of accounting. Gains and losses resulting from these transactions, recorded at market value, are deferred and recorded in Accumulated Other Comprehensive Income (AOCI) as appropriate, until recognized as operating income in Mariner s Statement of Operations as the physical production hedged by the contracts is delivered.

We are required to assess the effectiveness of all our derivative contracts at inception and at least every three months. 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 income statement. Loss of hedge accounting may cause volatility in earnings. Fair value is assessed, and measured and estimated by obtaining independent market quotes from counterparties and risk-free interest rate 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 financial statements change as estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

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

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

When the designated 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

Our natural gas, crude oil and NGL revenues are recorded using the entitlement method. Under the entitlement method, revenue is recorded when title passes based on Mariner s net interest or nominated deliveries. Mariner records its entitled share of revenues based on entitled volumes and contracted sales prices. The sales price for natural gas, crude oil and NGLs are adjusted for transportation cost and other related deductions. The transportation costs and other deductions are based on contractual or historical data and do not require significant judgment. Subsequently, these deductions and transportation costs are adjusted to reflect actual charges based on third party documents. Historically, these adjustments have been insignificant. Since there is a ready market for natural gas, crude oil and NGLs, Mariner sells the majority of its products soon after production at various locations at which time title and risk of loss pass to the buyer. As a result, Mariner maintains a minimum amount of product inventory in storage. Gas imbalances occur when Mariner sells more or less than its entitled ownership percentage of total gas production. Any amount received in excess (overproduction) of Mariner s share is treated as a liability. If Mariner receives less than it is entitled, the underproduction is recorded as a receivable. Imbalances are reduced either by subsequent recoupment of over-and-under deliveries or by cash settlement, as required by applicable contracts. Production imbalances are marked-to-market at the end of each month at the lowest of (i) the price in effect at the time of production; (ii) the current market price; or (iii) the contract price, if a contract is in hand.

Mariner s gas balancing assets and liabilities are not material, as oil and gas volumes sold are not significantly different from its share of production.

Stock Compensation Expense

We account for stock-based compensation in accordance with the fair value recognition provisions of SFAS 123(R), Share-Based Payment. Under the fair value recognition provisions of SFAS 123(R), stock-based compensation cost is measured at the grant date based on the value of the award and is recognized as expense over the vesting period. We utilize the Black-Scholes option pricing model to determine the fair value of stock-based awards on the grant date which requires judgment in estimating the expected life of the option and the expected volatility of our stock. Actual results could differ significantly from these estimates, and these differences could materially impact our financial position, results of operations and cash flows. In addition to the critical estimates discussed above, estimates are used in accounting and computing depreciation, depletion and amortization, the full cost ceiling, accruals of operating costs and production revenues.

Reclassifications and Use of Estimates in the Preparation of Financial Statements

Some amounts from the previous years have been reclassified to conform to the 2006 presentation of financial statements. These reclassifications do not affect net income.

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

Principles of Consolidation

Our consolidated financial statements include our accounts and the accounts of our wholly-owned subsidiaries. All significant inter-company balances and transactions have been eliminated.

Recent Accounting Pronouncements

In June 2006, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 06-03, How Taxes Collected from Customers and Remitted to Governmental Authorities Should be Presented in the Income Statement (That Is, Gross versus Net Presentation). EITF 06-03 requires that companies disclose the gross amounts of taxes reported. The consensus is effective for interim or annual reporting periods beginning after December 15, 2006. Adoption of this guidance did not materially impact our financial statements.

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, Accounting for Uncertainty in Income Taxes . FIN No. 48 clarifies SFAS No. 109, Accounting for Income Taxes, and requires that realization on an uncertain income tax position must be more-likely-than-not (i.e. greater than a 50 percent likelihood of receiving a benefit) before it can be recognized in the financial statements. Further, FIN No. 48 prescribes the benefit to be recorded in the financial statements as the amount most likely to be realized assuming a review by tax authorities having all relevant information and applying current conventions. FIN No. 48 also clarifies the financial statement classification of tax-related penalties and interest and sets forth new disclosures regarding unrecognized tax benefits. FIN No. 48 is effective for fiscal years beginning after December 15, 2006, and we will be required to adopt this interpretation in the first quarter of 2007. Based on our evaluation as of December 31, 2006, we do not believe that FIN No. 48 will have a material impact on our financial statements.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, which establishes guidelines for measuring fair value and expands disclosures regarding fair value measurements. SFAS No. 157

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does not require any new fair value measurements but rather it eliminates inconsistencies in the guidance found in various prior accounting pronouncements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. Earlier adoption is encouraged, provided the company has not yet issued financial statements, including for interim periods, for that fiscal year. Although we are still evaluating the potential effects of this standard, we do not expect the adoption of SFAS No. 157 to have a material impact on our consolidated financial position, results of operation, or cash flows.

In September 2006, the Securities and Exchange Commission released Staff Accounting Bulletin No. 108, Quantifying Financial Statement Misstatements (SAB 108). SAB 108 gives guidance on how errors, built up over time in the balance sheet, should be considered from a materiality perspective and corrected. SAB 108 provides interpretive guidance on how the effects of the carryover or reversal of prior year misstatements should be considered in quantifying a current year misstatement. SAB 108 represents the SEC Staff s views on the proper interpretation of existing rules and as such has no effective date. Adoption of this guidance did not materially impact our financial statements.

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

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Results of Operations

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

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

	Year Ended December 31, 2006	2005
	(In thousands, except average sales price)	
Summary Operating Information (1):		
Net production:		
Oil (MBbls)	4,075	1,791
Natural gas (MMcf)	56,064	18,354
Total (MMcfe)	80,512	29,100
Average daily production (MMcfe/d)	221	80
Hedging activities:		
Oil revenues gain (loss)	$ 90	$ (18,671)
Gas revenues gain (loss)	32,881	(30,613)
Total hedging revenues gain (loss)	$ 32,971	$ (49,284)
Average sales prices:		
Oil (per Bbl) realized(2)	$ 59.70	$ 41.23
Oil (per Bbl) unhedged	59.68	51.66
Natural gas (per Mcf) realized(2)	7.37	6.66
Natural gas (per Mcf) unhedged	6.78	8.33
Total natural gas equivalent ($/Mcfe) realized(2)	8.15	6.74
Total natural gas equivalent ($/Mcfe) unhedged	7.74	8.43
Oil and gas revenues:		
Oil sales	$ 243,251	$ 73,831
Gas sales	412,967	122,291
Total oil and gas revenues	656,218	196,122
Other revenues	3,287	3,588
Lease operating expenses	91,663	24,882
Severance and ad valorem taxes	8,998	5,000
Transportation expenses	5,077	2,336
Depreciation, depletion and amortization	292,162	59,426
General and administrative expenses	34,135	37,053
Impairment of production equipment held for use		1,845
Net interest expense	38,664	7,393
Income before taxes	188,806	61,775
Provision for income taxes	67,344	21,294

Net income	$ 121,462	$ 40,481

(1) In 2006, NGLs were combined with oil. In 2005, an immaterial amount of NGLs representing approximately 4% of our net production was combined with natural gas.

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

Net Production: Natural gas production increased 208% in 2006 to approximately 154 MMcf per day, compared to approximately 50 MMcf per day in 2005. Oil production increased 124% in 2006 to approximately 11,000 barrels per day, compared to approximately 4,900 barrels per day in 2005. Total production increased 176% in 2006 to approximately 221 MMcfe per day, compared to 80 MMcfe per day in 2005. Natural gas production comprised approximately 70% of total production in 2006 compared to approximately 63% in 2005. The increase in production and the gas to oil ratio primarily resulted from the acquisition of the Forest Gulf of Mexico operations. Production continued to be adversely affected by the 2005 hurricane season, resulting in shut-in production and startup delays. As a result of ongoing repairs to pipelines, facilities, terminals and host facilities, most of the shut-in production recommenced by the end of 2006.

In the last two quarters of 2005 our production was negatively impacted by Hurricanes Katrina and Rita. Production shut-in and deferred because of the hurricanes impact totaled approximately 6-8 Bcfe during the last two quarters of 2005. As of December 31, 2005 approximately 5 MMcfe per day of production remained shut-in awaiting repairs, primarily associated with our Green Canyon 178 (Baccarat) property, which was brought back on-line in January 2006. While we believe physical damage to our existing platforms and facilities was relatively minor from both hurricanes, the effects of the storms caused damage to onshore pipeline and processing facilities that resulted in a portion of our production being temporarily shut-in, or in the case of our Viosca Knoll 917 (Swordfish) project, postponed until the fourth quarter of 2005. In addition, Hurricane Katrina caused damage to platforms that host three of our development projects: Mississippi Canyon 718 (Pluto), Mississippi Canyon 296 (Rigel), and Mississippi Canyon 66 (Ochre). Our Rigel project recommenced production in the first quarter of 2006, and our Pluto and Ochre projects recommenced production in the third quarter of 2006.

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

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

Natural gas prices (excluding the effects of hedging) for 2006 averaged $6.78/Mcf compared to $8.33/Mcf for 2005. Oil prices (excluding the effects of hedging) for 2006 averaged $59.68/Bbl compared to $51.66/Bbl for 2005. For 2006, hedges increased average natural gas pricing by $0.59/Mcf to $7.37/Mcf and increased average oil pricing by $0.02/Bbl to $59.70/Bbl, resulting in a net recognized hedging gain of $33.0 million.

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

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

Severance and ad valorem taxes were $9.0 million and $5.0 million for 2006 and 2005, respectively. The increase was primarily attributable to increased production and appreciated property values on West Texas properties. For 2006 and 2005, severance and ad valorem taxes were $0.11 and $0.17 per Mcfe, respectively.

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

Depreciation, depletion, and amortization (DD&A) expense increased 392% to $292.2 million from $59.4 million for 2006 and 2005, respectively. The increase was a result of increased production due to the consolidation of the Forest Gulf of Mexico operations, as well as an increase in the unit-of-production depreciation, depletion and amortization rate. The per unit rate increased to $3.63 per Mcfe from $2.04 per Mcfe for 2006 and 2005, respectively. The per unit increase was primarily due to an increase in deepwater development activities and the Forest Gulf of Mexico operations, as well as increased accretion of asset retirement obligations due to the Forest Gulf of Mexico operations.

General and administrative (G&A) expense totaled $34.1 million for 2006, compared to $37.1 million for 2005. G&A expense includes charges for stock compensation expense of $10.2 million for 2006 compared to $25.7 million for 2005. For 2006, $6.6 million of compensation expense resulted from amortization of the cost of restricted stock granted at the closing of Mariner s equity private placement in March 2005 and the remaining related to the amortization of new grants issued in 2006 with vesting periods of three to four years. The restricted stock related to Mariner s equity private placement fully vested in May 2006 and there will be no future charges related to those stock grants. The 2005 compensation expense relates solely to the amortization of the restricted stock granted under Mariner s private equity placement. Included in the 2006 G&A expenses are severance, retention, relocation and transition costs of $2.6 million related to the acquisition of the Forest Gulf of Mexico operations. Salaries and wages for 2006 increased by $20.3 million compared to 2005. The increase was primarily the result of staffing additions related to the acquisition of the Forest Gulf of Mexico operations. In addition, 2005 included $2.3 million in payments to our former stockholders to terminate a services agreement. Reported G&A expenses for 2006 are net of $16.7 million of overhead reimbursements billed or received from other working interest owners, compared to $6.9 million for the comparable period of 2005, and capitalized general and administrative costs related to our acquisition, exploration and development activities during 2006 and 2005 of $11.0 million and $5.3 million, respectively.

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

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

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

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Year Ended December 31, 2005 compared to Year Ended December 31, 2004

Operating and Financial Results for the Year Ended December 31, 2005
Compared to the Year Ended December 31, 2004

Summary Operating Information (1):	Non-GAAP Combined Year Ended December 31, 2005	Non-GAAP Combined Year Ended December 31, 2004	Post-Merger Period from March 3, 2004 through December 31, 2004	Pre-Merger Period from January 1, 2004 through March 2, 2004
	(in thousands, except average sales price)			
Net production:				
Oil (MBbls)	1,791	2,298	1,885	413
Natural gas (MMcf)	18,354	23,782	19,549	4,233
Total (MMcfe)	29,100	37,569	30,856	6,713
Average daily production (MMcfe/d)	80	103	101	112
Hedging activities:				
Oil revenues (loss)	$ (18,671)	$ (12,300)	$ (11,614)	$ (686)
Gas revenues (loss)	(30,613)	(7,498)	(8,929)	1,431
Total hedging revenues (loss)	$ (49,284)	$ (19,798)	$ (20,543)	$ 745
Average sales prices:				
Oil (per Bbl) realized(2)	$ 41.23	$ 33.17	$ 33.69	$ 30.75
Oil (per Bbl) unhedged	51.66	38.52	39.86	32.41
Natural gas (per Mcf) realized(2)	6.66	5.80	5.67	6.39
Natural gas (per Mcf) unhedged	8.33	6.12	6.13	6.05
Total natural gas equivalent ($/Mcfe) realized(2)	6.74	5.70	5.65	5.92
Total natural gas equivalent ($/Mcfe) unhedged	8.43	6.23	6.32	5.81
Oil and gas revenues:				
Oil sales	$ 73,831	$ 76,207	$ 63,498	$ 12,709
Gas sales	122,291	137,980	110,925	27,055
Total oil and gas revenues	196,122	214,187	174,423	39,764
Other revenues	3,588			
Lease operating expenses	24,882	22,806	19,248	3,558
Severance and ad valorem taxes	5,000	2,678	2,115	563
Transportation expenses	2,336	3,029	1,959	1,070
Depreciation, depletion and amortization	59,426	64,911	54,281	10,630
General and administrative	37,053	8,772	7,641	1,131
Impairment of production equipment held for use	1,845	957	957	
Net interest expense (income)	7,393	5,734	5,820	(86)

Income before taxes	61,775	105,300	82,402	22,898
Provision for income taxes	21,294	36,855	28,783	8,072
Net income	$ 40,481	$ 68,445	$ 53,619	$ 14,826

(1) In 2005 and 2004, an immaterial amount of NGLs representing approximately 4% and 2%, respectively, of our net production was combined with natural gas.

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

Net production during 2005 decreased approximately 23% to 29.1 Bcfe from 37.6 Bcfe in 2004 primarily due to decreased Gulf of Mexico production, partially offset by increased onshore production. Mariner s production was negatively impacted during the third and fourth quarters of 2005 due to hurricane activity, primarily Katrina and Rita. Production shut-in and deferred because of the hurricanes impact totaled approximately 6-8 Bcfe during the third and fourth quarters of 2005. As of December 31, 2005, approximately 5 MMcfe per day of production remained shut-in awaiting repairs, primarily associated with our Baccarat property (although, production therefrom recommenced in January 2006). Additionally, production that was anticipated to commence in 2005 at our Swordfish, Ochre, Pluto, and Rigel development projects was delayed awaiting repairs to host facilities. Swordfish recommenced production in the fourth quarter of 2005, Rigel recommenced production in the first quarter of 2006, and Ochre and Pluto recommenced production in the third quarter of 2006.

Increased development drilling at our Aldwell unit in West Texas contributed to a 60% increase in onshore production to an average of approximately 18.1 MMcfe per day in 2005 from an average of approximately 11.3 MMcfe per day in 2004.

In the deepwater Gulf of Mexico, production decreased approximately 32% to an average of approximately 32.3 MMcfe per day in 2005 compared to an average of approximately 47.2 MMcfe per day in 2004. The decrease was largely due to reduced production at our Black Widow, Yosemite and Pluto fields. Pluto was shut-in in April 2004 pending drilling of the new Mississippi Canyon 674 #3 well and installation of an extension to the existing subsea facilities. Production at Black Widow and Yosemite was negatively impacted by hurricane activity as well as by expected declines. As previously discussed, hurricane-related delays in commencement of production at our Swordfish, Pluto and Rigel development projects also contributed to the production decline.

In the Gulf of Mexico shelf, production decreased by approximately 34% to an average of approximately 29.2 MMcfe per day in 2005 from an average of approximately 44.1 MMcfe per day in 2004. About 6.2 MMcfe per day of the decrease is attributable to our Ochre field, which remains shut-in due to the effects of Hurricane Ivan in September 2004 and Hurricanes Katrina and Rita in 2005. Production from three new shelf discoveries (Green Pepper, Royal Flush, and Dice) and production from the 2004 acquisition of interests in five offshore fields offset normal declines at our other Gulf of Mexico shelf fields and the impact of the 2005 hurricane season.

Hedging activities in 2005 decreased our average realized natural gas price received by $1.67 per Mcf and revenues by $30.6 million, compared with a decrease of $0.32 per Mcf and revenues of $7.5 million in 2004. Our hedging activities with respect to crude oil during 2005 decreased the average sales price received by $10.43 per barrel and revenues by $18.7 million compared with a decrease of $5.35 per barrel and revenues of $12.3 million for 2004.

Oil and gas revenues decreased 8% to $196.1 million in 2005 when compared to 2004 oil and gas revenues of $214.2 million, due to the aforementioned 23% decrease in production, partially offset by an 18% increase in realized prices (including the effects of hedging) to $6.74 per Mcfe in 2005 from $5.70 per Mcfe in 2004.

Other revenues of $3.6 million in 2005 represent an indemnity payment of $1.9 million received from our former stockholder related to the 2004 merger and $1.7 million generated by our West Texas Aldwell unit gathering system.

Lease operating expense increased 9% to $24.9 million in 2005 from $22.8 million in 2004. The increased costs were primarily attributable to the addition of new producing wells at our Aldwell Unit offset by reduced costs on our Black Widow, King Kong/Yosemite, and Pluto deepwater fields. On a per unit basis, lease operating expenses were $0.86 per Mcfe in 2005 compared to $0.61 per Mcfe in 2004. The increased per unit costs also reflect lower production rates in 2005, including hurricane-related disruptions.

Severance and ad valorem taxes were $5.0 million and $2.7 million for 2005 and 2004, respectively. The increase was primarily attributable to an increase in West Texas property values for ad valorem taxes. For 2005 and 2006, severance and ad valorem taxes were $0.17 and $0.07 per Mcfe, respectively.

Transportation expense was $2.3 million or $0.08 per Mcfe in 2005, compared to $3.0 million or $0.08 per Mcfe in 2004. The reduction is primarily attributable to our deepwater fields and includes reductions caused by the filing of new and higher transportation allowances with the MMS on two of our deepwater fields for purpose of royalty calculation.

DD&A expense decreased 8% to $59.4 million during 2005 from $64.9 million for 2004 as a result of decreased production of 8.5 Bcfe in 2005 compared to 2004, partially offset by an increase in the unit-of-production depreciation, depletion and amortization rate to $2.04 per Mcfe for 2005 from $1.73 per Mcfe for 2004. The per unit increase was primarily the result of an increase in future development costs on our deepwater development fields.

G&A expense, which is net of $6.9 million and $4.4 million of overhead reimbursements billed or received from other working interest owners in 2005 and 2004, respectively, increased 322% to $37.1 million during 2005 compared to $8.8 million in 2004. The increase was primarily due to recognizing $25.7 million in stock compensation expense related to restricted stock and options granted in 2005. We also paid $2.3 million to our former stockholders to terminate a services agreement in 2005, compared to $1.0 million under the same agreement in 2004. In addition, G&A expenses increased by $1.6 million due to a reduction in the amount of G&A capitalized, $6.9 million in 2005 compared to $5.3 million in 2004.

Impairment of production equipment held for use reflects the reduction of the carrying cost of our inventory by $1.8 million and $1.0 million as of December 31, 2005 and December 31, 2004, respectively. In 2005, the reduction in estimated value primarily related to subsea trees and wellhead equipment held in inventory.

Net interest expense for 2005 increased 25% to $7.4 million from $5.7 million in 2004, primarily due to higher average debt levels in 2005 compared to 2004. In connection with the merger on March 2, 2004, Mariner incurred $135 million in new bank debt and issued a $10 million promissory note to JEDI. For comparison purposes, approximately ten months of interest related to such borrowings is reflected in 2004 compared to twelve months of interest in 2005. Capitalized interest increased from $0.4 million in 2004 to $0.7 million in 2005.

Income before income taxes decreased to $61.8 million for 2005 compared to $105.3 million for 2004, attributable primarily to the decrease in oil and gas revenues resulting from the decreased production and increased G&A expenses, both as noted above. Offsetting these factors were the receipt of other income related to the indemnity payment and lower DD&A and transportation expenses.

Provision for income taxes decreased to $21.3 million for 2005 from $36.9 million for 2004 as a result of decreased operating income for 2005 compared to 2004.

Liquidity and Capital Resources

2006 Uses of Capital. Our primary needs for liquidity during 2006 were as follows:

- funding capital expenditures (excluding hurricane repairs and acquisitions) of approximately $513.6 million;
- funding hurricane repairs and hurricane-related abandonment expenditures of approximately $84.3 million;
- financing the West Cameron 110/111 preferential right acquisition of approximately $70.9 million;
- refinancing of approximately $176.2 million of debt assumed in connection with our acquisition of Forest s Gulf of Mexico operations;

paying debt service obligations of approximately $28.8 million; and

paying routine operating and administrative expenses.

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2006 Capital Expenditures. The following table presents major components of our capital expenditures during 2006 compared to 2005.

	Year Ended December 31, 2006	Year Ended December 31, 2005
Capital expenditures(1):		
Leasehold acquisitions	$ 22.4	$ 11.5
Oil and natural gas exploration	165.7	50.0
Oil and natural gas development	359.7	121.7
Proceeds from property conveyances(2)	(33.8)	
Acquisitions	70.9	53.4
Other items (primarily gathering system, capitalized overhead and interest)	15.0	16.1
Total capital expenditures, net of proceeds from property conveyances	$ 599.9	$ 252.7

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

(2) Proceeds from sale of Cottonwood project (Garden Banks 244) of $31.8 million are recorded as restricted cash (See Note 1, Significant Accounting Policies Restricted Cash).

2006 Hurricane Expenditures. During 2006, we had incurred approximately $84.3 million in hurricane expenditures resulting from Hurricanes Katrina and Rita, of which $68.8 million were repairs and $15.5 million were hurricane-related abandonment costs. Substantially all of the costs incurred pertained to the Gulf of Mexico assets acquired from Forest.

2006 Sources of Liquidity. Our primary sources of liquidity during 2006 were as follows:

cash flow from operations;

increase in borrowings under our bank credit facility discussed below; and

issuance of $300 million of 71/2% Senior Notes due 2013 discussed below.

Bank Credit Facility Mariner is party to a revolving line of credit with a syndicate of banks led by Union Bank of California, N.A. and BNP Paribas. The bank credit facility, which is secured by substantially all of our assets, provides up to $500 million of revolving borrowing capacity, including a $50 million subfacility for letters of credit, subject to a borrowing base, and a $40 million dedicated letter of credit. The borrowing base is based upon the evaluation by the lenders of the Company s oil and gas reserves and other factors. Effective March 22, 2007, the borrowing base was reaffirmed at $450 million. Any increase in the borrowing base requires the consent of all lenders. The bank credit facility will mature on March 2, 2010, and the letter of credit will mature on March 2, 2009.

The letter of credit was used to obtain a letter of credit in favor of Forest to secure Mariner s performance of its obligations to drill and complete 150 wells under an existing drill-to-earn program and is not included as a use of the borrowing base. This letter of credit reduces periodically by an amount equal to the product of $0.5 million times the number of wells exceeding 75 that are drilled and completed. As of January 2007, the letter of credit had been reduced by approximately $18 million based upon the 109 wells drilled and completed as of December 31, 2006. We expect additional reductions based upon quarterly drilling activity, with the next reduction anticipated in April 2007. The letter of credit balance as of December 31, 2006 was $35.7 million.

At December 31, 2006, Mariner had approximately $354.0 million in advances outstanding under the bank credit facility and four available letters of credit totaling $16.3 million, of which $14.6 million is required for plugging and abandonment obligations at certain of its offshore fields. The outstanding principal balance of loans under the bank credit facility may not exceed the borrowing base. If the borrowing base falls below the outstanding balance under the bank credit facility, Mariner will be required to repay the deficit, pledge additional unencumbered collateral, cash collateralize certain letters of credit, or effect some combination of such repayment, pledge and collateralization.

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

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

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

Mariner was in compliance with the financial covenants under the bank credit facility as of December 31, 2006.

71/2% Senior Notes due 2013 During 2006, Mariner sold and issued to eligible purchasers $300 million aggregate principal amount of its 71/2% Senior Notes due 2013 (the Notes). The Notes were priced to yield 7.75% to maturity. Net proceeds, after deducting initial purchasers discounts and commissions and offering expenses, were approximately $287.9 million. Mariner used the net proceeds of the offering to repay debt under the bank credit facility.

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

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

Mariner will pay interest on the Notes on April 15 and October 15 of each year. The Notes mature on April 15, 2013. There is no sinking fund for the Notes.

Mariner and its restricted subsidiaries are subject to certain negative covenants under the indenture governing the Notes. The indenture governing the Notes limits Mariner s and each of its restricted subsidiaries ability 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.

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

funding future capital expenditures;

funding hurricane repairs and hurricane-related abandonment operations;

financing any future acquisitions that Mariner may identify;

paying routine operating and administrative expenses; and

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

2007 Capital Expenditures. We anticipate that total capital expenditures for 2007 will approximate $658 million (excluding hurricane expenditures), with approximately 68% allocated to development activities, 30% to exploration activities, and the remainder to other items (primarily capitalized overhead and interest). In addition, we expect to incur additional hurricane-related abandonment costs related to Hurricanes Katrina and Rita of approximately $19.1 million during 2007, as well as additional facility repair costs that cannot be estimated at this time but which we do not believe will be material. While this will be a cash outflow in 2007, we expect to recover these costs through insurance reimbursements beginning in early 2007, although complete insurance settlement of all hurricane-related claims may take several additional quarters. See Business and Properties Insurance Matters under Items 1 and 2. Since we believe these costs to be reimbursable, they will not be reflected in reported 2007 capital expenditures.

Contractual Commitments

We have numerous contractual commitments in the ordinary course of business, debt service requirements and operating lease commitments. The following table summarizes these commitments at December 31, 2006:

	Total	Less Than One Year	1-3 Years	3-5 Years	More Than 5 Years
			(In millions)		
Debt obligations(1)	$ 654.0	$	$	$ 354.0	$ 300.0
Interest obligations(2)	146.3	27.2	45.0	45.0	29.1
Operating leases	7.6	1.5	3.7	2.4	
Abandonment liabilities	218.0	29.7	55.3	54.0	79.0
MMS Royalty liabilities	38.9	10.3	28.6		
Seismic obligations	24.1	20.1	4.0		
Capital accrual obligations	99.0	99.0			
Other liabilities	46.3	46.3			
Total contractual cash commitments	$ 1,234.2	$ 234.1	$ 136.6	$ 455.4	$ 408.1

(1) As of December 31, 2006, we had incurred debt obligations under our bank credit facility and the senior unsecured notes that are due on March 2, 2010 and April 15, 2013, respectively.

(2) Interest obligations represent interest due on the senior unsecured notes at 7.5%. Future interest obligations under our bank credit facility are uncertain, due to the variable interest rate on fluctuating balances. Based on a 8.0% weighted average interest rate on amounts outstanding under our bank credit facility as of December 31, 2006, $31.1 million, $56.6 million and $4.9 million would be due under the bank credit facility in less than one year, 1-3 years and 3-5 years, respectively.

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;

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- proceeds from insurance policies relating to hurricane repairs; and
- proceeds from future capital markets transactions as needed.

In 2007, we intend to tailor our capital program within our projected operating cash flow so that our operating capital requirements are largely self-sustaining under normal commodity price assumptions. We anticipate using proceeds under our bank credit facility only for working capital needs or acquisitions and not generally to fund our operations. We would generally expect to fund future acquisitions on a case by case basis through a combination of bank debt and capital markets activities. Based on our current operating plan and assumed price case, our expected cash flow from operations and continued access to our bank credit facility allow us ample liquidity to conduct our operations as planned for the foreseeable future.

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

Off-Balance Sheet Arrangements

Letters of Credit On March 2, 2006, Mariner obtained a $40 million letter of credit under its bank credit facility that is not included as a use of the borrowing base. The letter of credit was issued in favor of Forest to secure performance of our obligation to drill and complete 150 wells under an existing drill-to-earn program. This letter of credit will reduce periodically by an amount equal to the product of $0.5 million times the number of wells exceeding 75 that are drilled and completed. As of January 2007, the letter of credit had been reduced by approximately $18 million, based upon 109 wells drilled and completed as of December 31, 2006. We expect additional reductions based upon quarterly drilling activity, with the next reduction anticipated in April 2007. The letter of credit balance as of December 31, 2006 was $35.7 million.

Mariner s bank credit facility also has a letter of credit subfacility of up to $50 million that is included as a use of the borrowing base. As of December 31, 2006, four such letters of credit totaling $16.3 million were outstanding, $14.6 million of which is required for plugging and abandonment obligations at certain of Mariner s offshore fields.

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 2006 levels, a 10% decrease in commodity prices would impact our cash flow by approximately $62.3 million for the year ended December 31, 2006.

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. If 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 the income statement. Loss of hedge accounting and cash flow designation will cause

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volatility in earnings. The fair values we report in our 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.

As of December 31, 2006, Mariner had the following hedge contracts outstanding:

Fixed Price Swaps		Quantity	Weighted-Average Fixed Price	December 31, 2006 Fair Value Gain/(Loss) (In millions)
Natural Gas (MMBtus)				
January 1	December 31, 2007	15,846,323	$ 9.67	$ 47.9
January 1	September 30, 2008	3,059,689	$ 9.58	4.3
Total				$ 52.2

Costless Collars		Quantity	Floor	Cap	December 31, 2006 Fair Value Gain/(Loss) (In millions)
Crude Oil (Bbls)					
January 1	December 31, 2007	2,032,689	$ 59.84	$ 84.21	$ 0.7
January 1	December 31, 2008	1,195,495	$ 61.66	$ 86.80	3.4
Natural Gas (MMBtus)					
January 1	December 31, 2007	14,106,750	$ 6.87	$ 11.82	5.9
January 1	December 31, 2008	12,347,000	$ 7.83	$ 14.60	9.4
Total					$ 19.4

As of December 31, 2005, Mariner had the following hedge contracts outstanding:

Fixed Price Swaps		Quantity	Weighted-Average Fixed Price	December 31, 2005 Fair Value Gain/(Loss) (In millions)
Crude Oil (Bbls)				
January 1	December 31, 2006	140,160	$ 29.56	$ (4.7)
Natural Gas (MMBtus)				
January 1	December 31, 2006	1,827,547	$ 5.53	(9.9)

Total	$ (14.6)

Costless Collars		Quantity	Floor	Cap	December 31, 2005 Fair Value Gain/(Loss) (In millions)
Crude Oil (Bbls)					
January 1	December 31, 2006	251,850	$ 32.65	$ 41.52	$ (5.3)
January 1	December 31, 2007	202,575	$ 31.27	$ 39.83	(4.7)
Natural Gas (MMBtus)					
January 1	December 31, 2006	7,347,450	$ 5.78	$ 7.85	(22.3)
January 1	December 31, 2007	5,310,750	$ 5.49	$ 7.22	(16.9)
Total					$ (49.2)

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As of March 30, 2007, there were no hedging transactions entered into subsequent to December 31, 2006 except as follows:

Fixed Price Swaps	Quantity	Weighted-Average Fixed Price
Crude Oil (Bbls)		
June 1 December 31, 2007	627,900	$ 69.20
January 1 December 31, 2008	992,350	$ 69.34

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

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

	Year Ended December 31, 2006	2005	2004
Natural Gas			
Quantity settled (MMBtus)	30,547,997	15,917,159	18,823,063
Gain (Loss) on Natural Gas contracts settled (in thousands)	$ 11,182	$ (33,010)	$ (10,792)
Crude Oil			
Quantity settled (Mbbls)	1,645	836	1,554
Gain (Loss) on Crude Oil contracts settled (in thousands)	$ 90	$ (20,789)	$ (16,907)

The cash activity on contracts settled for natural gas and oil produced during 2006 resulted in an $11.3 million gain. An unrealized gain of $4.2 million was recognized for 2006 related to the ineffective portion of open contracts that were not eligible for deferral under SFAS 133 due primarily to the basis differentials between the contract price, which is NYMEX-based for oil and Henry Hub-based for gas, and the indexed price at the point of sale. In addition, the fair value of oil and natural gas derivatives acquired through the Forest Merger resulted in a $17.5 million non-cash gain. The fair value of the acquired derivatives was fully recognized in 2006. In accordance with purchase price accounting implemented at the time of the Merger of our former indirect parent on March 2, 2004, we recorded the mark-to-market liability of our hedge contracts at such date totaling $12.4 million as a liability on our balance sheet. See Critical Accounting Policies and Estimates Hedging Program. For the years ended December 31, 2005 and 2004, $4.5 million and $7.9 million, respectively, of the $53.8 million and $27.7 million total decrease in natural gas and oil sales, respectively, of cash hedge losses relate to the liability recorded at the time of the Merger.

Interest Rates

Borrowings under our bank credit facility, discussed above, mature on March 2, 2010, and bear interest at either a LIBOR-based rate or a prime-based rate, at our option, plus a specified margin. Both options expose us to risk of earnings loss due to changes in market rates. We have not entered into interest rate hedges that would mitigate such risk. During 2006, the interest rate on our outstanding bank debt averaged 7.34%. If the balance of our bank debt at December 31, 2006 were to remain constant, a 10% increase in market interest rates would impact our cash flow by approximately $2.5 million for the year ended December 31, 2006.

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

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors & Stockholders
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, 2006 and 2005 and the related consolidated statements of operations, stockholders equity and comprehensive income and cash flows for the years ended December 31, 2006 and 2005, for the period January 1, 2004 through March 2, 2004 (Pre-Merger), and for the period from March 3, 2004 through December 31, 2004 (Post-Merger). These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes 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, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Mariner Energy, Inc. and subsidiaries as of December 31, 2006 and 2005, and the results of its operations and cash flows for the years ended December 31, 2005 and 2006, for the period January 1, 2004 through March 2, 2004 (Pre-Merger), and for the period from March 3, 2004 through December 31, 2004 (Post-Merger) in conformity with accounting principles generally accepted in the United States of America.

As described in Note 1 to the Consolidated Financial Statements, on March 2, 2004, Mariner Energy LLC, the Company s parent company, merged with an affiliate of the private equity funds Carlyle/Riverstone Global Energy and Power Fund II, L.P. and ACON Investments LLC.

DELOITTE & TOUCHE LLP

Houston, Texas
March 30, 2007

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MARINER ENERGY, INC.

CONSOLIDATED BALANCE SHEETS

	December 31, 2006	December 31, 2005
	(in thousands except share data)	
Current Assets:		
Cash and cash equivalents	$ 9,579	$ 4,556
Receivables, net of allowances of $726 and $500 as of December 31, 2006 and 2005, respectively	149,692	84,109
Insurance receivables	61,001	4,542
Derivative financial instruments	54,488	
Prepaid seismic	20,835	6,542
Prepaid expenses and other	12,846	15,666
Deferred tax asset		26,017
Total current assets	308,441	141,432
Property and Equipment:		
Proved oil and gas properties, full-cost method	2,345,041	574,725
Unproved properties, not subject to amortization	40,246	40,176
Total Oil and Gas Properties	2,385,287	614,901
Other property and equipment	13,512	11,048
Accumulated depreciation, depletion and amortization	(386,737)	(110,006)
Total property and equipment, net	2,012,062	515,943
Restricted cash	31,830	
Goodwill	288,504	
Derivative financial instruments	17,153	
Other Assets, net of amortization	22,163	8,161
TOTAL ASSETS	$ 2,680,153	$ 665,536
Current Liabilities:		
Accounts payable	$ 1,822	$ 37,530
Accrued liabilities	74,880	75,324
Accrued capital costs	99,028	37,006
Deferred income tax	26,857	
Abandonment liability	29,660	11,359
Accrued interest	7,480	614
Derivative financial instruments		42,173
Total current liabilities	239,727	204,006
Long-Term Liabilities:		
Abandonment liability	188,310	38,176

Deferred income tax	262,888	25,886
Derivative financial instruments		21,632
Long term debt, bank credit facility	354,000	152,000
Long term debt, senior unsecured notes	300,000	
Note payable		4,000
Other long-term liabilities	32,637	6,500
Total long-term liabilities	1,137,835	248,194
Commitments and Contingencies (see Note 7)		
Stockholders Equity:		
Preferred stock, $.0001 par value; 20,000,000 shares authorized, no shares issued and outstanding at December 31, 2006 and December 31, 2005		
Common stock, $.0001 par value; 180,000,000 shares authorized, 86,375,840 shares issued and outstanding at December 31, 2006; 70,000,000 shares authorized, 35,615,400 shares issued and outstanding at December 31, 2005	9	4
Additional paid-in-capital	1,043,923	160,705
Accumulated other comprehensive income/(loss)	43,097	(41,473)
Accumulated retained earnings	215,562	94,100
Total stockholders equity	1,302,591	213,336
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 2,680,153	$ 665,536

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MARINER ENERGY, INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Post-Merger			Pre-Merger
	Year Ended December 31, 2006	Year Ended December 31, 2005	Period from March 3, 2004 through December 31, 2004	Period from January 1, 2004 through March 2, 2004
	(In thousands except share data)			
Revenues:				
Oil sales	$ 243,251	$ 73,831	$ 63,498	$ 12,709
Gas sales	412,967	122,291	110,925	27,055
Other revenues	3,287	3,588		
Total revenues	659,505	199,710	174,423	39,764
Costs and Expenses:				
Lease operating expense	91,663	24,882	19,248	3,558
Severance and ad valorem taxes	8,998	5,000	2,115	563
Transportation expense	5,077	2,336	1,959	1,070
General and administrative expense	34,135	37,053	7,641	1,131
Depreciation, depletion and amortization	292,162	59,426	54,281	10,630
Impairment of production equipment held for use		1,845	957	
Total costs and expenses	432,035	130,542	86,201	16,952
OPERATING INCOME	227,470	69,168	88,222	22,812
Interest:				
Income	985	779	225	91
Expense, net of amounts capitalized	(39,649)	(8,172)	(6,045)	(5)
Income before taxes	188,806	61,775	82,402	22,898
Provision for income taxes	(67,344)	(21,294)	(28,783)	(8,072)
NET INCOME	$ 121,462	$ 40,481	$ 53,619	$ 14,826
Earnings per share:				
Net income per share basic	$ 1.59	$ 1.24	$ 1.80	$ 0.50
Net income per share diluted	$ 1.58	$ 1.20	$ 1.80	$ 0.50
Weighted average shares outstanding basic	76,352,666	32,667,582	29,748,130	29,748,130
Weighted average shares outstanding diluted	76,810,466	33,766,577	29,748,130	29,748,130

The accompanying notes are an integral part of these financial statements

MARINER ENERGY, INC.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY AND COMPREHENSIVE INCOME

	Common Shares	Stock Amount	Additional Paid-In Capital	Accumulated Other Comprehensive Income (Loss) (In thousands)	Accumulated Retained Earnings (Deficit)	Total Stockholders Equity
Balance at December 31, 2003	29,748	$ 1	$ 227,318	$ (4,360)	$ (4,802)	$ 218,157
Pre-Merger Net Income					14,826	14,826
Change in fair value of derivative hedging instruments				(7,312)		(7,312)
Hedge settlements reclassified to income				(745)		(745)
Total comprehensive income				(8,057)	14,826	6,769
Pre-Merger Balance at March 2, 2004	29,748	$ 1	$ 227,318	$ (12,417)	$ 10,024	$ 224,926
Post-Merger						
Dividend					(166,432)	(166,432)
Merger adjustments			(135,401)	12,417	156,408	33,424
Balance at March 3, 2004	29,748	$ 1	$ 91,917	$	$	$ 91,918
Net income					53,619	53,619
Change in fair value of derivative hedging instruments net of income taxes of ($17,323)				(32,171)		(32,171)
Hedge settlements reclassified to income net of income taxes of $11,061				20,541		20,541
Total comprehensive income (loss)				(11,630)	53,619	41,989
Balance at December 31, 2004	29,748	$ 1	$ 91,917	$ (11,630)	$ 53,619	$ 133,907
Common shares issued private equity offering	3,600	2	44,331			44,333
Common shares issued restricted stock	2,267	1	(1)			
			25,129			25,129

Amortization of unearned compensation						
Stock compensation expense stock options			594			594
Contributed capital Mariner Energy, LLC and Mariner Holdings, Inc.			3,057			3,057
Merger adjustments			(4,322)			(4,322)
Comprehensive income:						
Net income					40,481	40,481
Other comprehensive income (loss):						
Change in fair value of derivative hedging instruments net of income taxes of ($33,318)				(61,878)		(61,878)
Hedge settlements reclassified to income net of income taxes of $17,249				32,035		32,035
Total comprehensive income (loss)				(29,843)	40,481	10,638
Balance at December 31, 2005	35,615	$ 4	$ 160,705	$ (41,473)	$ 94,100	$ 213,336
Common shares issued Forest transaction	50,637	$ 5	886,142			886,147
Common shares issued restricted stock	907					
Treasury stock bought and cancelled on same day	(808)		(14,028)			(14,028)
Forfeiture of restricted stock	(27)					
Amortization of unearned compensation			9,248			9,248
Stock compensation expense stock options			980			980
Stock options exercised	52		718			718
Merger adjustments			158			158
Comprehensive income:						
Net income					121,462	121,462
Other comprehensive income:						
Change in fair value of derivative hedging instruments net of income taxes of $35,930				63,139		63,139
Hedge settlements reclassified to income net of income taxes of $11,540				21,431		21,431
Total comprehensive income				84,570	121,462	206,032
Balance at December 31, 2006	86,376	$ 9	$ 1,043,923	$ 43,097	$ 215,562	$ 1,302,591

The accompanying notes are an integral part of these financial statements

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MARINER ENERGY, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Post-Merger			Pre-Merger
	Year Ended December 31, 2006	Year Ended December 31, 2005	Period from March 3, 2004 through December 31, 2004	Period from January 1, 2004 through March 2, 2004
	(In thousands)			
Operating Activities:				
Net income	$ 121,462	$ 40,481	$ 53,619	$ 14,826
Adjustments to reconcile net loss to net cash provided by operating activities:				
Deferred income tax	67,344	21,294	27,162	8,072
Depreciation, depletion and amortization	295,292	60,640	55,067	10,630
Ineffectiveness of derivative instruments	(4,175)			
Stock compensation	10,229	25,726		
Impairment of production equipment held for use		1,845	957	
Changes in operating assets and liabilities:				
Receivables	(12,746)	(32,916)	(10,615)	(8,847)
Insurance receivables	(55,690)	(4,542)		
Prepaid expenses and other	15,774	(5,201)	(965)	551
Other assets	2,852	4,358	321	(963)
Accounts payable and accrued liabilities	(169,819)	53,759	9,697	(3,974)
Net realized loss on derivative contracts acquired	6,638			
Net cash provided by operating activities	277,161	165,444	135,243	20,295
Investing Activities:				
Acquisitions and additions to property and equipment	(542,581)	(247,817)	(133,597)	(15,342)
Property conveyances	33,829	18		
Purchase price adjustment	(20,808)		620	1
Restricted cash designated for investment	(31,830)			
Net cash used in investing activities	(561,390)	(247,799)	(132,977)	(15,341)
Financing Activities:				
Initial borrowings from bank credit facility, net of fees			131,579	
	(176,200)			

Debt and working capital acquired from Forest Energy Resources, Inc.								
Repayment of term note		(4,000)		(6,000)				
Credit facility borrowings (repayments), net		202,000		47,000		(30,000)		
Proceeds from private equity offering				44,331				
Proceeds from note offering		300,000						
Repurchase of stock		(14,027)						
Net realized loss on derivative contracts acquired		(6,638)						
Proceeds from exercise of stock options		718						
Deferred offering costs		(12,601)		(3,840)				
Capital contribution from affiliates				2,879				
Dividend to Mariner Energy LLC						(166,432)		
Net cash provided by (used in) financing activities		289,252		84,370		(64,853)		
Increase (Decrease) in Cash and Cash Equivalents		5,023		2,015		(62,587)		4,954
Cash and Cash Equivalents at Beginning of Period		4,556		2,541		65,128		60,174
Cash and Cash Equivalents at End of Period	$	9,579	$	4,556	$	2,541	$	65,128

The accompanying notes are an integral part of these financial statements

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1. Summary of Significant Accounting Policies

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

Organization On March 2, 2004, Mariner Energy LLC, the parent company of Mariner Energy, Inc. (the Company), merged with a subsidiary of MEI Acquisitions Holdings, LLC, an affiliate of the private equity funds Carlyle/Riverstone Global Energy and Power Fund II, L.P. and ACON Investments LLC (the Merger). Prior to the Merger, Joint Energy Development Investments Limited Partnership (JEDI), which was an indirect wholly-owned subsidiary of Enron Corp. (Enron), owned approximately 96% of the common stock of Mariner Energy LLC. In the Merger, all the shares of common stock in Mariner Energy LLC were converted into the right to receive cash and certain other consideration. As a result, JEDI no longer owns any interest in Mariner Energy LLC, and the Company is no longer affiliated with JEDI or Enron.

Simultaneously with the Merger, the Company obtained a revolving line of credit with initial advances of $135 million from a group of banks. The loan proceeds and an additional $31.2 million of Company funds distributed to Mariner Energy LLC were used to pay a portion of the gross Merger consideration (which included repayment of $197.6 million of Mariner Energy LLC debt outstanding at the time of the Merger) and estimated transaction costs and expenses associated with the Merger and bank financing. The Company also issued a $10 million note and assigned a fully reserved receivable valued at $1.9 million to JEDI as part of JEDI s Merger consideration. In addition, pursuant to the Merger agreement, JEDI agreed to indemnify the Company from certain liabilities and the Company agreed to pay additional Merger consideration contingent upon the outcome of a certain five well drilling program that was completed in the second quarter of 2004. In September 2004, the Company paid approximately $161,000 as additional Merger consideration related to the five well drilling program, and the Company believes it has fully discharged its obligations thereunder.

The sources and uses of funds related to the Merger were as follows:

Mariner Energy, Inc. bank loan proceeds	$ 135.0
Note payable issued by Mariner Energy, Inc. to former parent	10.0
Equity from new owners	100.0
Distributions from Mariner Energy, Inc.	31.2
Assignment by Mariner Energy, Inc. of receivables	1.9
Total	$ 278.1
Repayment of former parent debt obligation	$ 197.6
Merger consideration to stockholders and warrant holders	73.5
Acquisition costs and other expenses	7.0

Total	$ 278.1

As a result of the change in control, accounting principles generally accepted in the United States require the Merger and the resulting acquisition of Mariner Energy LLC by MEI Acquisitions Holdings, LLC to be accounted for as a purchase transaction in accordance with Statement of Financial Accounting Standards No. 141, Business Combinations . Staff Accounting Bulletin No. 54 (SAB 54) requires the application of push down accounting in situations where the ownership of an entity has changed, meaning that the post-transaction financial statements of the Company reflect the new basis of accounting. Accordingly, the financial

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statements as of December 31, 2004 reflect the Company s fair value basis resulting from the acquisition that has been pushed down to the Company. The aggregate purchase price has been allocated to the underlying assets and liabilities based upon the respective estimated fair values at March 2, 2004 (merger date). The allocation of the purchase price has been finalized. Carryover basis accounting applies for tax purposes. Based on subsequent tax filings during the year ended December 31, 2005, the Company recorded a $4.3 million adjustment to the estimated tax basis at acquisition. All financial information presented prior to March 2, 2004 represents the basis of accounting used by the Pre-Merger entity. The period January 1, 2004 through March 2, 2004 is referred to as 2004 Pre-Merger and the period March 3, 2004 through December 31, 2004 is referred to as 2004 Post-Merger.

The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at the March 2, 2004 acquisition:

ALLOCATION OF PURCHASE PRICE TO MARINER ENERGY, INC.

	March 2, 2004 (In millions)	
Oil and natural gas properties-proved	$	203.5
Oil and natural gas properties-unproved		25.2
Other property and equipment and other assets		0.7
Current assets		83.2
Deferred tax asset(1)		9.1
Other assets		4.6
Accounts payable and accrued expenses		(62.2)
Long-Term Liability		(14.7)
Fair value of oil and natural gas derivatives		(12.4)
Debt		(145.0)
Total Allocation	$	92.0

(1) Represents deferred income taxes recorded at the date of the Merger due to differences between the book basis and the tax basis of assets. For book purposes, we had a step-up in basis related to purchase accounting while our existing tax basis carried over.

The following reflects the unaudited pro forma results of operations as though the Merger had been consummated at January 1, 2004.

		Twelve Months Ending December 31, 2004 (In millions)
Revenues and other income	$	214.2
Income before taxes and change in accounting method		103.0
Net income		67.0

On February 10, 2005, in anticipation of the Company s private placement of 31,452,500 shares of common stock (the Private Equity Offering), Mariner Holdings, Inc. (the direct parent of Mariner Energy, Inc.) and Mariner Energy LLC (the direct parent of Mariner Holdings, Inc.) were merged into Mariner Energy,

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Inc. and ceased to exist. The mergers of Mariner Holdings, Inc. and Mariner Energy LLC into the Company had no operational or financial impact on the Company; however, intercompany receivables of $0.2 million and $2.9 million in cash held by the affiliates were transferred to the Company in February 2005 and accounted for as additional paid-in capital.

On March 2, 2006, a subsidiary of the Company completed the Forest Merger. As a result of the Forest Merger, the Company acquired the offshore Gulf of Mexico operations of Forest Oil Corporation (Forest) and amended and restated the Company s bank credit facility. For further discussion of this transaction, please see Note 3, Acquisitions and Dispositions.

Significant Accounting Policies

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

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

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

Insurance receivables As a result of Hurricanes Ivan, Katrina and Rita in 2004 and 2005, we incurred a substantial amount of damage to our properties. As costs are incurred to bring the properties back to operating condition, we are reclassifying these costs to insurance receivables, net of any deductible, as we believe that these costs are reimbursable under our insurance policies. Any differences between our insurance recoveries and insurance receivables will be recorded as an adjustment to oil and gas properties.

Oil and Gas Properties Our oil and gas properties are accounted for using the full-cost method of accounting. All direct costs and certain indirect costs associated with the acquisition, exploration and development of oil and gas properties are capitalized. Amortization of oil and gas properties is provided using the unit-of-production method based on estimated proved oil and gas reserves. No gains or losses are recognized upon the sale or disposition of oil and gas properties unless the sale or disposition represents a significant quantity of oil and gas reserves, which would have a significant impact on the depreciation, depletion and amortization rate.

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

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

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

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

Prepaid Expenses and Other Prepaid expenses and other includes $2.4 million of oil and gas lease and well equipment held in inventory and $4.9 million of prepaid insurance at December 31, 2006. In 2005, we reduced the carrying amount of our inventory by $1.8 million to account for a reduction in the estimated value, primarily related to subsea trees and wellhead equipment held in inventory. Other current assets also includes prepaid insurance, deposits and escrow accounts.

Other Assets Other assets at December 31, 2006 were primarily comprised of $10.2 million of amortizable note offering costs and discounts, $1.1 million of amortizable bank fees and $4.0 million of prepaid seismic costs with the remaining balance consisting of long term deposits of $6.7 million. Other assets as of December 31, 2005 were primarily comprised of $1.4 million of amortizable bank fees, $2.3 million in noncurrent receivables and $4.3 million of prepaid seismic costs. Accumulated amortization as of December 31, 2006 and 2005 was $5.0 million and $2.1 million, respectively.

Goodwill Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed in the acquisition. We account for goodwill in accordance with Statement of Financial Accounting Standards (SFAS) No. 142, Goodwill and Other Intangible Assets . SFAS No. 142 requires an annual impairment assessment and a more frequent assessment if certain events occur that indicate impairment may have occurred. We performed the goodwill impairment assessment in the fourth

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quarter of 2006. The initial impairment assessment compares the Company s net book value to its estimated fair value. If impairment is indicated, then the Company is required to make estimates of the fair value of goodwill. The estimated fair value of goodwill is based on many factors, including future net cash flows of estimated proved reserves as well as the success of future exploration and development of unproved reserves. If the carrying amount of goodwill exceeds the estimated fair value, then a measurement of the loss is performed with any excess charged to expense. To date, no impairment to goodwill has been recorded.

Income Taxes Our provision for taxes includes both state and federal taxes. The Company records its federal income taxes using an asset and liability approach which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax bases of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and 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 apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from these estimates, which could impact our financial position, results of operations and cash flows.

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

Abandonment Liability Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations, addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 was adopted on January 1, 2003. SFAS No. 143 requires that the fair value of a liability for an asset s retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized.

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

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

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		(In millions)
Abandonment Liability as of December 31, 2004	$	24.0
Liabilities Incurred		28.6
Liabilities Settled		(5.5)
Accretion Expense		2.4
Abandonment Liability as of December 31, 2005(1)	$	49.5
Liabilities Incurred		29.6
Liabilities Settled		(31.1)
Accretion Expense		15.3
Revisions to previous estimates		(10.5)
Liabilities incurred from assets acquired(2)		165.2
Abandonment Liability as of December 31, 2006(3)	$	218.0

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

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

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

Hedging Program The Company utilizes derivative instruments in the form of natural gas and crude oil price swap agreements and costless collar arrangements in order to manage price risk associated with future crude oil and natural gas production and fixed-price crude oil and natural gas purchase and sale commitments. Such agreements are accounted for as hedges using the deferral method of accounting. Gains and losses resulting from these transactions, recorded at market value, are deferred and recorded in Accumulated Other Comprehensive Income (AOCI) as appropriate, until recognized as operating income in the Company s Statement of Operations as the physical production hedged by the contracts is delivered.

We are required to assess the effectiveness of all our derivative contracts at inception and at least every three months. 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 income statement. Loss of hedge accounting may cause volatility in earnings. Fair value is assessed, and measured and estimated by obtaining independent market quotes from counterparties and risk-free interest rate 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 financial statements change as estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

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

The conditions to be met for a derivative instrument to qualify as a cash flow hedge are the following: (i) the item to be hedged exposes the Company to price risk; (ii) the derivative reduces the risk exposure and is designated as a hedge at the time the derivative contract is entered into; and (iii) at the inception of the

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hedge and throughout the hedge period there is a high correlation of changes in the market value of the derivative instrument and the fair value of the underlying item being hedged.

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

Financial Instruments The Company s financial instruments consist of cash and cash equivalents, restricted cash, receivables, derivatives, payables and outstanding debt. The carrying amount of the Company s other instruments noted above approximate fair value due to the short-term nature of these investments. The carrying amount of our long-term debt approximates fair value as the interest rates are generally indexed to current market rates.

Revenue Recognition Our natural gas, crude oil and NGL revenues are recorded using the entitlement method. Under the entitlement method, revenue is recorded when title passes based on the Company s net interest or nominated deliveries. The Company records its entitled share of revenues based on entitled volumes and contracted sales prices. The sales price for natural gas, crude oil and NGLs are adjusted for transportation cost and other related deductions. The transportation costs and other deductions are based on contractual or historical data and do not require significant judgment. Subsequently, these deductions and transportation costs are adjusted to reflect actual charges based on third party documents. Historically, these adjustments have been insignificant. Since there is a ready market for natural gas, crude oil and NGLs, the Company sells the majority of its products soon after production at various locations at which time title and risk of loss pass to the buyer. As a result, the Company maintains a minimum amount of product inventory in storage. Gas imbalances occur when the Company sells more or less than its entitled ownership percentage of total gas production. Any amount received in excess (overproduction) of the Company s share is treated as a liability. If the Company receives less than it is entitled, the underproduction is recorded as a receivable. Imbalances are reduced either by subsequent recoupment of over-and-under deliveries or by cash settlement, as required by applicable contracts. Production imbalances are marked-to-market at the end of each month at the lowest of (i) the price in effect at the time of production; (ii) the current market price; or (iii) the contract price, if a contract is in hand.

The Company s gas balancing assets and liabilities are not material as oil and gas volumes sold are not significantly different from the Company s share of production.

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

Operating Costs We classify our operating costs as lease operating expense, severance and ad valorem taxes, transportation expense and general and administrative expense. Lease operating expense is comprised of those costs and expenses necessary to produce oil and gas after an individual well or field has been completed and prepared for production. These costs include direct costs such as field operations, general maintenance expenses, workovers and the costs associated with production handling agreements for most of our deepwater

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

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

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

General and administrative expense includes employee compensation costs (including stock compensation expense), the costs of third party consultants and professionals, rent and other costs of leasing and maintaining office space, the costs of maintaining computer hardware and software, and insurance and other items.

General and Administrative Costs and Expense Under the full-cost method of accounting, a portion of our general and administrative expenses that are directly attributable to our acquisition, exploration and development activities are capitalized as part of our full-cost pool. These capitalized costs include salaries, employee benefits, costs of consulting services and other costs directly identified with acquisition exploration and development activities. We capitalized general and administrative costs related to our acquisition, exploration and development activities were approximately $11.0 million for 2006, $5.3 million for 2005, and $5.7 million and $1.1 million for 2004 Post-Merger and 2004 Pre-Merger, respectively.

We receive reimbursement for administrative and overhead expenses incurred on behalf of other working interest owners on properties we operate. These reimbursements totaling $16.7 million, $6.9 million and $4.4 million for the years ended December 31, 2006, 2005 and 2004, respectively, were allocated as reductions to general and administrative expenses incurred. Generally, we do not receive any reimbursements or fees in excess of the costs incurred; however, if we did, we would credit the excess to the full-cost pool to be recognized through lower cost amortization as production occurs.

Accounting for Stock Options and Restricted Stock The Company adopted SFAS No. 123 Revised 2004, Shared Based Payment, using the modified retrospective application effective January 1, 2005. As a result of the adoption of SFAS No. 123(R), we record compensation expense for the fair value of restricted stock that was granted pursuant to our Equity Participation Plan and for grants of stock options or restricted stock made pursuant to Mariner Energy, Inc. s Stock Incentive Plan. We determine compensation expense for the restricted stock grants equal to their fair value at the date of grant. The fair value will then be amortized to compensation expense over the applicable vesting period.

Capitalized Interest Costs The Company capitalizes interest based on the cost of major development projects which are excluded from current depreciation, depletion, and amortization calculations. Capitalized interest costs were approximately $1.5 million for 2006, $0.7 million for 2005, and $0.4 and $-0- million for 2004 Post-Merger and 2004 Pre-Merger, respectively.

Reclassifications and Use of Estimates in the Preparation of Financial Statements Some amounts from the previous years have been reclassified to conform to the 2006 presentation of financial statements. These reclassifications do not affect net income.

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

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Principles of Consolidation Our consolidated financial statements include our accounts and the accounts of our wholly-owned subsidiaries. All significant inter-company balances and transactions have been eliminated.

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.

	Post-Merger			Pre-Merger
	Year Ended December 31, 2006	Year Ended December 31, 2005	Period from March 3, 2004 through December 31, 2004	Period from January 1, 2004 through March 2, 2004
	(In thousands except per share data)			
Numerator:				
Net income	$ 121,462	$ 40,481	$ 53,619	$ 14,826
Denominator:				
Weighted average shares outstanding	76,353	32,668	29,748	29,748
Add dilutive securities	457	1,099		
Total weighted average shares outstanding and dilutive securities	76,810	33,767	29,748	29,748
Net income per share basic:	$ 1.59	$ 1.24	$ 1.80	$ .50
Net income per share diluted:	$ 1.58	$ 1.20	$ 1.80	$ .50

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

For the periods presented prior to 2005, Mariner Energy, Inc. had no outstanding stock options so the basic and diluted earnings per share were the same. Please refer to Note 5 Stockholder s Equity for option and share activity for the years ending December 31, 2006 and 2005, respectively. Outstanding restricted stock and unexercised stock options diluted earnings by $0.01 and $0.04 per share for the years ended December 31, 2006 and 2005, respectively.

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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, 2006, 2005, 2004 Post-Merger and 2004 Pre-Merger:

	Post-Merger			Pre-Merger
	Year Ended December 31, 2006	Year Ended December 31, 2005	Period from March 3, 2004 through December 31, 2004	Period from January 1, 2004 through March 2, 2004
	(In thousands)			
Net Income	$ 121,462	$ 40,481	$ 53,619	$ 14,826
Other comprehensive income (loss), net of tax				
Derivative contracts settled and reclassified, net of tax	21,431	32,035	20,541	(745)
Change in unrealized mark to market gains/(losses) arising during period, net of tax	63,139	(61,878)	(32,171)	(7,312)
Change in accumulated other comprehensive income (loss)	84,570	(29,843)	(11,630)	(8,057)
Comprehensive income	$ 206,032	$ 10,638	$ 41,989	$ 6,769

Major Customers During the twelve months ended December 31, 2006, sales of oil and gas to three purchasers accounted for 23%, 14% and 11% of total revenues. During the year ended December 31, 2005, sales of oil and gas to three purchasers accounted for 24%, 10% and 15% of total revenues. During the year ended December 31, 2004, sales of oil and gas to three purchasers accounted for 27%, 18% and 12% of total revenues. Management believes that the loss of any of these purchasers would not have a material impact on the Company s financial condition, results of operations or cash flows.

Percentage of Total Revenues for Year Ended December 31,

Customer	**2006**	**2005**	**2004**
BP Energy	14%	*	12%
Bridgeline Gas Distributing Company(**)		15%	27%
ChevronTexaco and affiliates(**)	23%	24%	18%
Louis Dreyfus Energy	10%	7%	*
Plains Marketing LP	11%	10%	

* Less than 1%

** Bridgeline Gas Distributing Company is an affiliate of ChevronTexaco

No activity in the period

Recent Accounting Pronouncements In June 2006, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 06-03, How Taxes Collected from Customers and Remitted to Governmental Authorities Should be Presented in the Income Statement (That Is, Gross versus Net Presentation) . EITF 06-03 requires that companies disclose the gross amounts of taxes reported. The consensus is effective for

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interim or annual reporting periods beginning after December 15, 2006.. Adoption of this guidance did not materially impact our financial statements.

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, Accounting for Uncertainty in Income Taxes. FIN No. 48 clarifies SFAS No. 109, Accounting for Income Taxes, and requires that realization on an uncertain income tax position must be more-likely-than-not (i.e. greater than a 50 percent likelihood of receiving a benefit) before it can be recognized in the financial statements. Further, FIN No. 48 prescribes the benefit to be recorded in the financial statements as the amount most likely to be realized assuming a review by tax authorities having all relevant information and applying current conventions. FIN No. 48 also clarifies the financial statement classification of tax-related penalties and interest and sets forth new disclosures regarding unrecognized tax benefits. FIN No. 48 is effective for fiscal years beginning after December 15, 2006, and we will be required to adopt this interpretation in the first quarter of 2007. Based on our evaluation as of December 31, 2006, we do not believe that FIN No. 48 will have a material impact on our financial statements

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

In September 2006, the Securities and Exchange Commission released Staff Accounting Bulletin No. 108, Quantifying Financial Statement Misstatements (SAB 108). SAB 108 gives guidance on how errors, built up over time in the balance sheet, should be considered from a materiality perspective and corrected. SAB 108 provides interpretive guidance on how the effects of the carryover or reversal of prior year misstatements should be considered in quantifying a current year misstatement. SAB 108 represents the SEC Staff s views on the proper interpretation of existing rules and as such has no effective date. Adoption of this guidance did not materially impact our financial statements.

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

2. Related Party Transactions

Organization and Ownership of the Company On March 2, 2004, Mariner Energy LLC, the Company s indirect parent, merged with a subsidiary of MEI Acquisitions Holdings, LLC, an affiliate of the private equity funds Carlyle/Riverstone Global Energy and Power Fund II, L.P. and ACON Investments LLC (the Merger). Prior to the Merger, Joint Energy Development Investments Limited Partnership (JEDI), which was an

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indirect wholly-owned subsidiary of Enron Corp. (Enron), owned approximately 96% of the common stock of Mariner Energy LLC. In the Merger, all the shares of common stock in Mariner Energy LLC were converted into the right to receive cash and certain other consideration. As a result, JEDI no longer owned any interest in Mariner Energy LLC, and the Company ceased to be affiliated with JEDI or Enron.

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

The Company was previously party to management agreements with two affiliates of its former parent company. These agreements provided for the payment by Mariner Energy LLC of an aggregate of $2.5 million to the affiliates in connection with the provision of management services. Such payments have been made. Mariner Energy LLC also entered into monitoring agreements with two affiliates of its former parent, providing for the payment by Mariner Energy LLC to the affiliates in connection with certain monitoring activities. Under the terms of the monitoring agreements, the affiliates provided financial advisory services in connection with the ongoing operations of Mariner. Effective February 7, 2005, these contracts were terminated in consideration of lump sum cash payments by Mariner totaling $2.3 million. The Company recorded the termination payments as general and administrative expenses for the quarter ended March 31, 2005.

3. Acquisitions and Dispositions

Forest Gulf of Mexico Operations On March 2, 2006, a subsidiary of the Company completed a merger transaction with Forest Energy Resources, Inc. (the Forest Merger). Prior to the consummation of the Forest Merger, Forest Oil Corporation (Forest) transferred and contributed the assets of, and certain liabilities associated with, its offshore Gulf of Mexico operations to Forest Energy Resources, Inc. Immediately prior to the Forest Merger, Forest distributed all of the outstanding shares of Forest Energy Resources, Inc. to Forest shareholders on a pro rata basis. Forest Energy Resources, Inc. then merged with a newly formed subsidiary of Mariner, became a new wholly owned subsidiary of Mariner and changed its name to Mariner Energy Resources, Inc. (MERI). Immediately following the Forest Merger, approximately 59% of the Mariner common stock was held by shareholders of Forest and approximately 41% of Mariner common stock was held by the Pre-Merger stockholders of Mariner.

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

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The Forest Merger was accounted for using the purchase method of accounting under the accounting standards established in SFAS No. 141, Business Combinations (SFAS 141) and No. 142, Goodwill and Other Intangible Assets. As a result, the assets and liabilities acquired by Mariner in the Forest Merger are included in the Company s December 31, 2006 balance sheet. The Company reflected the results of operations of the Forest Merger beginning March 2, 2006. The Company recorded the estimated fair values of the assets acquired and liabilities assumed at the March 2, 2006 closing date, which are summarized in the following table:

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

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

The purchase price allocation has been finalized. In 2006, we recorded a $19.9 million goodwill adjustment primarily related to insurance receivables and deferred taxes. In April 2006, Mariner made a preliminary cash payment to Forest of $20.8 million recorded as an offset to current liabilities. Carryover basis accounting applies for tax purposes.

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

Pro Forma Financial Information The pro forma information set forth below gives effect to the Forest Merger as if it had been consummated as of the beginning of the applicable period. The Forest Merger was consummated on March 2, 2006. The pro forma information has been derived from the historical consolidated financial statements of the Company and the statements of revenues and direct operating expenses of the Forest Gulf of Mexico operations. The pro forma information is for illustrative purposes only. The financial results may have been different had the Forest Gulf of Mexico operations been an independent company and had the companies always been combined. You should not rely on the pro forma financial information as being indicative of the historical results that would have been achieved had the Forest Merger occurred in the past or the future financial results that the Company will achieve after the Forest Merger.

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

West Cameron 110/111 On August 7, 2006, the Company exercised its preferential right to purchase the interest of BP Exploration and Production Inc. (BP) in West Cameron Block 110 and the southeast quadrant of West Cameron Block of 111 in the Gulf of Mexico. BP retained rights to depths below 15,000 feet. The acquisition cost was $70.9 million, which was financed by borrowing under our bank credit facility. A $10.4 million letter of credit under our bank credit facility was also issued in favor of BP to secure plugging and abandonment liabilities. The acquisition adds proved reserves estimated by Mariner to be 20 Bcfe as of August 1, 2006.

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

4. Long-Term Debt

Bank Credit Facility On March 2, 2004, the Company obtained a revolving line of credit with initial advances of $135 million from a group of banks led by Union Bank of California, N.A. and BNP Paribas. The bank credit facility initially provided up to $150 million of revolving borrowing capacity, subject to a borrowing base, and a $25 million term loan. The initial advance was made in two tranches: a $110 million Tranche A and a $25 million Tranche B. The Tranche B loan was converted to a Tranche A note in July 2004 and all subsequent advances under the bank credit facility were Tranche A advances.

The borrowing base is based upon the evaluation by the lenders of the Company s oil and gas reserves and other factors. Any increase in the borrowing base requires the consent of all lenders. Substantially all of the Company s assets are pledged to secure the bank credit facility.

Amendments of Bank Credit Facility In connection with the Forest Merger, the Company amended and restated its existing bank credit facility on March 2, 2006 to, among other things, increase maximum credit availability to $500 million for revolving loans, including up to $50 million in letters of credit, with a $400 million borrowing base as of that date; add an additional dedicated $40 million letter of bank credit facility that does not affect the borrowing base; and add MERI as a co-borrower. The bank credit facility will mature on March 2, 2010, and the $40 million letter of credit will mature on March 2, 2009. The Company used borrowings under its bank credit facility to facilitate the Forest Merger and to retire existing debt, and it

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may use borrowings in the future for general corporate purposes. The $40 million letter of credit was used to obtain a letter of credit in favor of Forest to secure the Company s performance of its obligations to drill and complete 150 wells under an existing drill-to-earn program and is not included as a use of the borrowing base. This letter of credit will reduce periodically by an amount equal to the product of $0.5 million times the number of wells exceeding 75 that are drilled and completed. The first reduction of approximately $4.3 million occurred in October 2006 based upon the 83 wells drilled and completed as of September 30, 2006. As of January 2007, a reduction of approximately $18 million occurred based upon the 109 wells drilled and completed as of December 31, 2006. We expect additional reductions based upon quarterly drilling activity, with the next reduction anticipated in April 2007. The letter of credit balance as of December 31, 2006 was $35.7 million.

At December 31, 2006, the Company had approximately $354.0 million in advances outstanding under its bank credit facility and four available letters of credit totaling $16.3 million, of which $14.6 million is required for plugging and abandonment obligations at certain of its offshore fields. The outstanding principal balance of loans under the bank credit facility may not exceed the borrowing base. If the borrowing base falls below the outstanding balance under the bank credit facility, the Company will be required to prepay the deficit, pledge additional unencumbered collateral, repay the deficit and cash collateralize certain letters of credit, or effect some combination of such prepayment, pledge and repayment and collateralization. Effective March 22, 2007, the borrowing base was reaffirmed at $450 million, subject to redetermination or adjustment.

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

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

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

The Company was in compliance with the financial covenants under the bank credit facility as of December 31, 2006.

As of December 31, 2006 and December 31, 2005, $354.0 million and $152.0 million, respectively, was outstanding under the bank credit facility, and the weighted average interest rate was 7.29% and 7.15%, respectively.

The Company must pay a commitment fee of 0.25% to 0.375% per year on the unused availability under the amended bank credit facility dated March 2, 2006.

Private Offering of 71/2% Senior Notes due 2013 On April 24, 2006, the Company sold and issued to eligible purchasers $300 million aggregate principal amount of its 71/2% Senior Notes due 2013 (the Notes) pursuant to Rule 144A under the Securities Act of 1933, as amended. The Notes were priced to yield 7.75% to maturity. Net proceeds, after deducting initial purchasers discounts and commissions and offering expenses, were approximately

$287.9 million. Mariner used the net proceeds of the offering to repay debt under the bank credit facility. The issuance of the Notes was a qualifying bond issuance under Mariner s bank credit facility and resulted in an automatic reduction of its borrowing base to $362.5 million as of April 24, 2006. On November 9, 2006, the Company replaced the original Notes issued in the private placement with new Notes with identical terms and tenor through an exchange offer registered under the Securities Act of 1933.

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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 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 Company will pay interest on the Notes on April 15 and October 15 of each year. The Notes mature on April 15, 2013. There is no sinking fund for the Notes.

The Company may redeem the Notes at any time prior to April 15, 2010 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 April 15 of the years 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:

2010 at 103.750%
2011 at 101.875%
2012 and thereafter at 100.000%

In addition, prior to April 15, 2009, the Company may redeem up to 35% of the Notes with the proceeds of equity offerings at a price equal to 107.50% of the principal amount of the Notes redeemed. If the Company experiences a change of control (as defined in the indenture governing the Notes), subject to certain exceptions, the Company must give holders of the Notes the opportunity to sell to the Company their Notes, in whole or in part, at a purchase price equal to 101% of the principal amount, plus accrued and unpaid interest and liquidated damages to the date of purchase.

The Company and its restricted subsidiaries are subject to certain negative covenants under the indenture governing the Notes. The indenture governing the Notes limits the Company s and each of its restricted subsidiaries ability 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;

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

create unrestricted subsidiaries.

Costs associated with the Notes offering were approximately $8.5 million, excluding discounts of $3.8 million.

JEDI Term Promissory Note On March 2, 2004, the Company issued a $10 million term promissory note to JEDI as a part of merger consideration. The note matured on March 2, 2006, and bore interest, payable in kind at our option, at a rate of 10% per annum until March 2, 2005, and 12% per annum thereafter unless paid in cash in which event the rate remained 10% per annum. We chose to pay interest in cash rather than in kind. The JEDI note was secured by a lien on three of the Company s non-proven, non-producing properties located in the Outer Continental Shelf of the Gulf of Mexico. The Company could offset against the note the amount of certain claims for indemnification that could be asserted against JEDI under the terms of the merger agreement. The JEDI term promissory note contained customary events of default, including the occurrence of an event of default under the Company s bank credit facility. In March 2005, the Company repaid $6.0 million of the note utilizing proceeds from the Private Equity Placement in March 2005. The $4.0 million balance remaining on the JEDI note was repaid in full on its maturity date of March 2, 2006.

Cash Interest Expense For the years ended December 31, 2006 and 2005, interest payments were $28.8 million and $6.1 million, respectively. Cash paid for interest was $5.4 million and $-0- for 2004 Post-Merger and 2004 Pre-Merger, respectively.

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

5. Stockholders Equity

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

Equity Participation Plan We adopted an Equity Participation Plan, as amended, that provided for the one-time grant at the closing of our Private Equity Placement on March 11, 2005 of 2,267,270 restricted shares of our common stock to certain of our employees. No further grants will be made under the Equity Participation Plan, although persons who received such a grant are eligible for future awards of restricted stock or stock options under our Stock Incentive Plan, as amended or restated from time to time, described below. We intended the grants of restricted stock under the Equity Participation Plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of our common stock. Therefore, Equity Participation Plan grantees did not pay any consideration for the common stock they received, and we received no remuneration for the stock. As a result of closing the Forest Merger, all shares of restricted stock granted under the Equity Participation Plan vested as follows: (i) the 463,656 shares of restricted stock held by non-executive employees vested on March 2, 2006, and (ii) the 1,803,614 shares of restricted stock held by executive officers vested on May 31, 2006 pursuant to an agreement, made in exchange for a cash payment of $1,000 to each officer, that his or her shares of restricted

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stock would not vest before the later of March 11, 2006 or ninety days after the effective date of the Forest Merger. The Equity Participation Plan expired upon the vesting of all shares granted thereunder. Stock could be withheld by us upon vesting to satisfy our tax withholding obligations with respect to the vesting of the restricted stock. Participants in the Equity Participation Plan had the right to elect to have us withhold and cancel shares of the restricted stock to satisfy our tax withholding obligations. In such events, we would be required to pay any tax withholding obligation in cash. As a result of such participant elections, we withheld an aggregate 807,376 shares that otherwise would have remained outstanding upon vesting of the restricted stock, reducing the aggregate outstanding vested stock grants made under the Equity Participation Plan to 1,459,894 shares. The 807,376 shares withheld became treasury shares that were retired and restored to the status of authorized and unissued shares of common stock, and the Company s capital was reduced by an amount equal to the $.0001 par value of the retired shares. We paid in cash the associated withholding taxes of $14.0 million, of which $3.3 million and $10.7 million were paid in the first and second quarter of 2006, respectively.

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

During the 12 months ended December 31, 2006, we granted 907,371 shares of restricted common stock under the Stock Incentive Plan. As of December 31, 2006, 875,380 shares of unvested restricted common stock and options exercisable for 707,920 shares of the Company s common stock remained outstanding under the Stock Incentive Plan, of which 345,256 were presently exercisable and 362,664 are expected to vest through 2008. Under the Stock Incentive Plan, 4,862,132 shares remain available for future issuance to participants. During the 12 months ended December 31, 2006, 4,500 shares of restricted stock vested, resulting in withholding tax obligations. Plan participants can elect to have us withhold and cancel shares of restricted stock to satisfy the associated tax withholding obligations. In such event, we would be required to pay any tax withholding obligation in cash. As a result of such participant elections, we withheld an aggregate 532 shares that otherwise would have remained outstanding upon vesting of the restricted stock. The shares withheld became treasury shares that were retired and restored to the status of authorized and unissued shares of common stock, and the Company s capital was reduced by an amount equal to the $.0001 par value of the retired shares. We paid in cash the associated withholding taxes of approximately $10,000.

During the 12 months ended December 31, 2005, we granted options to purchase 809,000 shares of common stock under the Stock Incentive Plan.

Rollover Options In connection with the Forest Merger and during the 12 months ended December 31, 2006, the Company granted options to acquire 156,626 shares of its common stock to certain former employees of Forest or Forest Energy Resources, Inc. (Rollover Options). The Rollover Options are evidenced by non-qualified stock option agreements and are not covered by the Stock Incentive Plan. As of December 31, 2006, Rollover Options to purchase 94,402 shares of the Company s common stock remained outstanding, of which 27,465 were presently exercisable, and 66,937 are expected to vest through 2009.

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Accounting for Stock Options and Restricted Stock The Company adopted SFAS No. 123-Revised 2004 (SFAS No. 123(R)), *Share-Based Payment,* using the modified retrospective application effective January 1, 2005. As a result of the adoption of SFAS No. 123(R), we recorded compensation expense for the fair value of restricted stock that was granted pursuant to our Equity Participation Plan. We also record compensation expense for the value of restricted stock and options granted under the Stock Incentive Plan. In general, compensation expense will be determined at the date of grant based on the fair value of the stock or options granted. The fair value will then be amortized to compensation expense over the applicable vesting period. We recorded compensation expense of $10.2 million and $25.7 million for the 12-month periods ended December 31, 2006 and 2005, respectively, related to restricted stock grants in 2005 and 2006 and stock options outstanding for the periods then ended. As of May 31, 2006, the participants were fully vested in the restricted stock granted under the Equity Participation Plan and no unrecognized compensation remains. Under the Stock Incentive Plan, unrecognized compensation expense at December 31, 2006 for the unvested portion of restricted stock granted was $14.6 million and for unvested options was $0.7 million. For the year ended December 31, 2004, the Company had no outstanding options or restricted stock, therefore, no stock compensation expense was recognized during the year.

The following table presents a summary of stock option activity for the year ended December 31, 2006:

	Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value (1) ($000)
Outstanding at beginning of year	809,000	$ 14.02	
Granted(2)	156,626	$ 11.99	
Exercised	(51,458)	$ 13.96	
Forfeited(3)	(111,846)	$ 13.01	
Outstanding at end of year	802,322	$ 13.77	$ 4,678
Vested and expected to vest	706,871	$ 14.00	3,959
Outstanding exercisable at end of year	372,721	$ 13.86	2,140
Available for future grant as options or restricted stock	4,862,132		

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

(2)

The options exercisable for an aggregate 156,626 shares were Rollover Options granted pursuant to the Forest Transaction merger agreement. The options exercisable for an aggregate 809,000 shares were granted under the Stock Incentive Plan.

(3) Rollover Options exercisable for an aggregate 61,366 shares and options exercisable for 41,480 shares granted under the Stock Incentive Plan were forfeited due to terminations of employment, but are not indicative of a historical forfeiture rate. In-the-money options exercisable for an aggregate 9,000 shares granted under the Stock Incentive Plan to two directors of the Company were cancelled on March 31, 2006 and replaced by restricted stock grants.

For the year ended December 31, 2006, 51,458 options were exercised resulting in a $718,000 increase in cash and a $63,177 windfall tax deduction in excess of previously recorded tax benefits, based on the option value at the time of grant. These windfalls are reflected in net operating tax carryforwards pursuant to SFAS 123(R), but the additional tax benefit associated with the windfall is not recognized until the deduction reduces taxes payable.

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The following table summarizes certain information about stock options outstanding at December 31, 2006:

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

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

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

Options generally vest over one to three-year periods and are exercisable for periods ranging from seven to ten years. The weighted average fair value of options granted during 2006 and 2005 was $2.58 and $2.69, respectively. The fair value of each option award is estimated on the date of grant using the Black-Scholes option valuation model. The assumptions utilized in 2005 and 2006 are noted in the following table:

	12 Months Ended December 31,		
	2006		2005
Black-Scholes Assumptions	**Stock Incentive Plan Options(1)**	**Rollover Options(2)**	**Stock Incentive Plan Options**
Expected Term (years)	6.0	4.7	3.0
Risk Free Interest Rate	4.80%	4.79%	3.79%
Expected Volatility	35%	35%	38%
Dividend Yield	0.00%	0.00%	0.00%

(1) Stock Incentive Plan as amended and restated

(2) There were no Rollover Options in 2005

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

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

A summary of the activity for unvested restricted stock awards under the Stock Incentive Plan as of December 31, 2006 and 2005, respectively, and changes during the 12-month period is as follows:

	Restricted Shares under the Amended and Restated Stock Incentive Plan December 31,	
	2006	2005
Total unvested shares at beginning of period: January 1		
Shares granted	907,371	
Shares vested	(4,500)	
Shares forfeited	(27,491)	
Total unvested shares at end of period: December 31	875,380	
Total vested shares at end of period: December 31	4,500	
Available for future grant as options or restricted stock	4,862,132	
Average fair value of shares granted during the period	$ 19.54	$

A summary of the activity for unvested restricted stock share awards under the Equity Participation Plan as of December 31, 2006 and 2005, respectively, and changes during the 12-month periods is as follows:

	Restricted Shares under the Equity Participation Plan December 31,	
	2006	2005
Total unvested shares at beginning of period: January 1	2,267,270	
Shares granted		2,267,270
Shares vested	(2,267,270)	
Shares forfeited		
Total unvested shares at end of period: December 31		2,267,270

Total vested shares at end of period: December 31	2,267,270		
Available for future grant under Equity Participation Plan			
Average fair value of shares granted during the period	$	$	14.00

Private Equity Placement. In March 2005, the Company sold and issued 16,350,000 shares of its common stock in the Private Equity Placement for net proceeds of $212.9 million, before offering expenses of $2.2 million, of which $166.0 million were used to redeem 12,750,000 shares of the Company s common stock from its sole stockholder.

6. Employee Benefit and Royalty Plans

Employee Capital Accumulation Plan The Company provides all full-time employees (who are at least 18 years of age) participation in the Employee Capital Accumulation Plan (the Plan) which is comprised of a contributory 401(k) savings plan and a discretionary profit sharing plan. Under the 401(k) feature, the

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Company, at its sole discretion, may contribute an employer-matching contribution equal to a percentage not to exceed 50% of each eligible participant s matched salary reduction contribution as defined by the Plan. Under the discretionary profit sharing contribution feature of the Plan, the Company s contribution, if any, must be determined annually and must be 4% of the lesser of the Company s operating income or total employee compensation and shall be allocated to each eligible participant pro rata to his or her compensation. The Company contributed $720,426 in 2006, $240,650 in 2005, and $193,521 in 2004, respectively. Currently there are no plans to terminate the Plan.

Overriding Royalty Interests Pursuant to agreements, certain employees and consultants of the Company are entitled to receive, as incentive compensation, overriding royalty interests (Overriding Royalty Interests) in certain oil and gas prospects acquired by the Company. Such Overriding Royalty Interests entitle the holder to receive a specified percentage of the gross proceeds from the future sale of oil and gas (less production taxes), if any, applicable to the prospects. Cash payments made by the Company to current employees and consultants with respect to Overriding Royalty Interests were $2.0 million for 2006, $2.6 million for 2005, and $2.5 million and $0.2 million for 2004 Post-Merger and 2004 Pre-Merger, respectively.

7. Commitments and Contingencies

Minimum Future Lease Payments The Company leases certain office facilities and other equipment under long-term operating lease arrangements. Minimum rental obligations under the Company s operating leases in effect at December 31, 2006 are as follows (in thousands):

2007	$ 1,459
2008	1,317
2009	1,086
2010	1,328
2011 and thereafter	2,371

Rental expense, before capitalization, was approximately $1.2 million for 2006, $0.5 million for 2005, and $0.5 and $-0- million, respectively for 2004 Post-Merger and 2004 Pre-Merger, respectively.

Hedging Program The energy markets have historically been very volatile, and we expect that oil and gas prices will be subject to wide fluctuations in the future. In an effort to reduce the effects of the volatility of the price of oil and natural gas on the Company s operations, management has elected to hedge oil and natural gas prices from time to time through the use of commodity price swap agreements and costless collars. While the use of these hedging arrangements limits the downside risk of adverse price movements, it also limits future gains from favorable movements. In addition, forward price curves and estimates of future volatility are used to assess and measure the ineffectiveness of our open contracts at the end of each period. If open contracts cease to qualify for hedge accounting, the mark to market change in fair value is recognized in the income statement. Loss of hedge accounting and cash flow designation will cause volatility in earnings. The fair values we report in our 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 cash activity on contracts settled for natural gas and oil produced during 2006 resulted in an $11.3 million gain. An unrealized gain of $4.2 million was recognized for 2006 related to the ineffective portion of open contracts that were not eligible for deferral under SFAS 133 due primarily to the basis differentials between the contract price, which is NYMEX-based for oil and Henry Hub-based for gas, and the indexed price at the point of sale. In addition, the fair value of oil and natural gas derivatives acquired through the Forest Merger resulted in a $17.5 million non-cash gain. The fair value of the acquired derivatives was

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fully recognized in 2006. Hedge gains and losses are recorded by commodity type in oil and gas sales in the Statement of Operations.

As of December 31, 2006, the Company had the following fixed price swaps outstanding:

Fixed Price Swaps	Quantity	Weighted-Average Fixed Price	December 31, 2006 Fair Value Gain/(Loss) (In millions)
Natural Gas (Mmbtus)			
January 1 December 31, 2007	15,846,323	$ 9.67	$ 47.9
January 1 December 31, 2008	3,059,689	$ 9.58	4.3
Total			$ 52.2

As of December 31, 2006, the Company had the following costless collars outstanding:

Costless Collars	Quantity	Floor	Cap	December 31, 2006 Fair Value Gain/(Loss) (In millions)
Crude Oil (Bbls)				
January 1 December 31, 2007	2,032,689	$ 59.84	$ 84.21	$ 0.7
January 1 December 31, 2008	1,195,495	$ 61.66	$ 86.80	3.4
Natural Gas (MMBtus)				
January 1 December 31, 2007	14,106,750	$ 6.87	$ 11.82	5.9
January 1 December 31, 2008	12,347,000	$ 7.83	$ 14.60	9.4
Total				$ 19.4

As of December 31, 2005, the Company had the following fixed price swaps outstanding:

Fixed Price Swaps	Quantity		Weighted-Average Fixed Price		December 31, 2005 Fair Value Gain/(Loss) (In millions)
Crude Oil (Bbls)					
January 1 December 31, 2006	140,160	$	29.56	$	(4.7)
Natural Gas (MMBtus)					
January 1 December 31, 2006	1,827,547	$	5.53		(9.9)
Total				$	(14.6)

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As of December 31, 2005, the Company had the following costless collars outstanding:

Costless Collars	Quantity	Floor	Cap	December 31, 2005 Fair Value Gain/(Loss) (In millions)
Crude Oil (Bbls)				
January 1 December 31, 2006	251,850	$ 32.65	$ 41.52	$ (5.3)
January 1 December 31, 2007	202,575	$ 31.27	$ 39.83	(4.7)
Natural Gas (MMbtus)				
January 1 December 31, 2006	7,347,450	$ 5.78	$ 7.85	(22.3)
January 1 December 31, 2007	5,310,750	$ 5.49	$ 7.22	(16.9)
Total				$ (49.2)

As of March 30, 2007, the Company has not entered into any hedge transactions subsequent to December 31, 2006 except as follows:

Fixed Price Swaps	Quantity	Weighted-Average Fixed Price
Crude Oil (Bbls)		
June 1 December 31, 2007	627,900	$ 69.20
January 1 December 31, 2008	992,350	$ 69.34

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

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

	Post-Merger		Pre-Merger
		Period from	Period from

	Year Ended December 31, 2006	Year Ended December 31, 2005	March 3, 2004 through December 31, 2004	January 1, 2004 through March 2, 2004
	(Dollars in thousands except per share data)			
Natural Gas				
Quantity hedged (MMbtu)	30,547,997	15,917,159	16,723,063	2,100,000
Gain (Loss) on Natural Gas contracts settled (in thousands)	$ 11,182	$ (33,010)	$ (12,223)	$ 1,431
Crude Oil				
Quantity hedged (MBbls)	1,645	836	1,375	179
Gain (Loss) on Crude Oil contracts settled (in thousands)	$ 90	$ (20,789)	$ (16,221)	$ (686)

The Company s hedge transactions resulted in a $33.0 million gain for 2006, a $53.8 million loss for 2005 and a $28.4 million loss for 2004 Post-Merger and a $0.7 million gain for 2004 Pre-Merger. $4.5 million of the 2005 loss and $7.9 million of the Post-Merger loss relates to the hedge liability recorded at the merger

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date. Hedge gains and losses are recorded by commodity type in oil and gas sales in the Statement of Operations.

Other Commitments In the ordinary course of business, the Company enters into long-term commitments to purchase seismic data. The minimum annual payments under these contracts are $19.5 million and $4.0 million in 2007 and 2008, respectively. In 2005, the Company entered into a joint exploration agreement granting the joint venture partner the right to participate in prospects covered by certain seismic data licensed by the Company in return for $6.0 million in scheduled payments to be received by the Company over a two-year period.

MMS Proceedings Mariner and a subsidiary own numerous properties in the Gulf of Mexico. Certain of such properties were leased from the Minerals Management Service (MMS) subject to the 1996 Royalty Relief Act. This Act relieved lessees of the obligation to pay royalties on certain leases until a designated volume was produced. Two of these leases held by the Company and one held by MERI contained language that limited royalty relief if commodity prices exceeded predetermined levels. Since 2000, commodity prices have exceeded the predetermined levels, except in 2002. The Company and its subsidiary believe the MMS did not have the authority to include commodity price threshold language in these leases and have withheld payment of royalties on the leases while disputing the MMS authority in two pending proceedings. The Company has recorded a liability for 100% of the estimated exposure on its two leases, which at December 31, 2006 was $21.2 million, including interest. Various legal proceedings are pending concerning this potential liability and further proceedings may be initiated with respect to years not covered by the pending proceedings. In April 2005, the MMS denied Mariner s administrative appeal of the MMS April 2001 order asserting royalties were due because price thresholds had been exceeded. In October 2005, Mariner filed suit in the U.S. District Court for the Southern District of Texas seeking judicial review of the dismissal. Upon motion of the MMS, the Company s lawsuit was dismissed on procedural grounds. In August 2006, the Company filed an appeal of such dismissal. In May 2006, the MMS issued an order asserting price thresholds were exceeded in calendar years 2001, 2003 and 2004 and, accordingly, that royalties were due under such leases on oil and gas produced in those years. Mariner has filed and is pursuing an administrative appeal of that order. The MMS has not yet made demand for non-payment of royalties alleged to be due for calendar years subsequent to 2004 on the basis of price thresholds being exceeded.

The potential liability of MERI under its lease subject to the 1996 Royalty Relief Act containing such commodity price threshold language, including interest, is approximately $2.6 million as of December 31, 2006, and a reserve of that amount was recorded as of December 31, 2006. This potential liability relates to production from the lease commencing July 1, 2005, the effective date of Mariner s acquisition of MERI.

Insurance Matters

Hurricanes Katrina and Rita (2005)

In 2005, our operations were adversely affected by one of the most active and severe hurricane seasons in recorded history, resulting in substantial shut-in and delayed production, as well as necessitating extensive facility repairs and hurricane-related abandonment operations. Throughout 2006 we completed substantial facility repairs that successfully returned substantially all of our shut-in properties to production without the loss of material reserves.

As of December 31, 2006, we had incurred approximately $84.3 million in hurricane expenditures resulting from Hurricanes Katrina and Rita, of which $68.8 million were repairs and $15.5 million were hurricane-related abandonment costs. Substantially all of the costs incurred to date pertained to the Gulf of

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Mexico assets acquired from Forest. We estimate that we will incur additional hurricane-related abandonment costs of approximately $19.1 million during 2007, as well as additional facility repair costs that cannot be estimated at this time but which we do not believe will be material.

Under the terms of the acquisition from Forest, we are responsible for performing all facility repairs and hurricane-related abandonment operations on Forest s Gulf assets at our expense, and we are entitled to receive all related insurance proceeds under Forest s insurance policies at the time of the storms, subject to our meeting Forest s deductibles. At year end, we recorded an insurance receivable of approximately $56.3 million, net of deductibles, for facility repair costs in excess of insurance deductibles inasmuch as we believe it is probable that these costs will be reimbursed under Forest s insurance policies. Moreover, we believe substantially all hurricane-related abandonment costs expended to date should also be covered under Forest s insurance.

Forest s primary insurance coverage for Katrina and Rita was provided through OIL Insurance, Ltd., an energy industry insurance cooperative. The terms of Forest s coverage included a deductible of $5 million per occurrence and a $1 billion industry-wide loss limit per occurrence. OIL has advised us that the aggregate claims resulting from each of Hurricanes Katrina and Rita are expected to exceed the $1 billion per occurrence loss limit and that our insurance recovery relating to Forest s Gulf of Mexico assets is therefore expected to be reduced pro rata with all other competing claims from the storms. To the extent insurance recovery under the primary OIL policy is reduced, Mariner believes the shortfall would be covered under Forest s commercial excess insurance coverage. Forest s excess coverage is not subject to an additional deductible and has a stated limit of $50 million. Mariner does not believe the hurricane related costs associated with Mariner s legacy properties (as opposed to those acquired from Forest) will exceed Mariner s $3.8 million deductible and we do not anticipate making a claim under our insurance.

Taking into account Forest s insurance coverage in effect at the time of Hurricanes Katrina and Rita, we currently estimate our unreimbursed losses from hurricane-related repairs and abandonments should not exceed $15 million. However, due to the magnitude of the storms and the complexity of the insurance claims being processed by the insurance industry, the timing of our ultimate insurance recovery cannot be ascertained. Although we expect to begin receiving insurance proceeds in the first half of 2007, we believe that full settlement of all hurricane-related insurance claims may take several quarters to complete. As a result, we expect to maintain a possibly significant insurance receivable for the indefinite future while we actively pursue settlement of our claims to minimize the impact to our working capital and liquidity. Any differences between our insurance recoveries and insurance receivables will be recorded as adjustments to our oil and gas properties.

Hurricane Ivan (2004)

In September 2004, we incurred damage from Hurricane Ivan that affected the Mississippi Canyon 66 (Ochre) and Mississippi Canyon 357 fields. Ochre production was shut-in until September 2006, when host platform repairs were completed and production recommenced at approximately the same net rate. Mississippi Canyon 357 production was shut-in until March 2005, when necessary repairs were completed and production recommenced, however production was subsequently shut-in due to Hurricane Katrina and is expected to recommence in the first quarter of 2007. As of December 31, 2006, we had incurred approximately $8.7 million of property damage related to Hurricane Ivan. To date, approximately $2.4 million has been recovered through insurance, with the balance of $4.7 million, net of deductible, recorded as insurance receivable, as we believe it is probable that these costs will be reimbursed under our insurance policies.

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Current Insurance Against Hurricanes

Effective March 2, 2006, Mariner was accepted as a member of OIL Insurance, Ltd. As a result, all of our properties are now insured through OIL. The coverage contains a $5 million annual per-occurrence deductible for the Company s assets and a $250 million per-occurrence loss limit. However, if a single event causes losses to OIL insured assets in excess of $500 million for Atlantic Named Windstorms (ANWS) or $750 million for non-ANWS events, amounts covered for such losses will be reduced on a pro rata basis among OIL members. Our current commercially underwritten insurance coverage for all Mariner assets is effective through June 1, 2007, and will pay out after OIL coverage has eroded. We have acquired additional windstorm/physical damage insurance covering all of Mariner s assets to supplement the existing OIL coverage. The coverage provides up to $51 million of annual loss coverage (with no additional deductible) if recoveries from OIL for insured losses are reduced by the OIL overall loss limit (i.e., if losses to OIL insured assets from a single event exceed $500 million for ANWS or $750 million for non-ANWS event).

In June 2006, we acquired additional limited business interruption insurance on most of our deepwater producing fields which becomes effective 60 days after a field is shut-in due to a covered event. The coverage varies by field and is limited to a maximum recovery resulting from windstorm damage of approximately $43 million (assuming all covered fields are shut-in for the full insurance term of 365 days).

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

Letters of Credit On March 2, 2006, Mariner obtained a $40 million letter of credit under its bank credit facility that is not included as a use of the borrowing base. The letter of credit was issued in favor of Forest to secure performance of our obligation to drill and complete 150 wells under an existing drill-to-earn program. This letter of credit will reduce periodically by an amount equal to the product of $0.5 million times the number of wells exceeding 75 that are drilled and completed. As of January 2007, the letter of credit had been reduced by approximately $18 million based upon 109 wells drilled and completed as of December 31, 2006. We expect additional reductions based upon quarterly drilling activity, with the next reduction anticipated in April 2007. The letter of credit balance as of December 31, 2006 was $35.7 million.

Mariner s bank credit facility also has a letter of credit of up to $50 million that is included as a use of the borrowing base. As of December 31, 2006, four such letters of credit totaling $16.3 million were outstanding. $14.6 million of this is required for plugging and abandonment obligations at certain of Mariner s offshore fields.

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8. Income Taxes

The components of the federal income tax provision are:

	Post-Merger			Pre-Merger
	Year Ending December 31, 2006	Year Ending December 31, 2005	Period from March 3, 2004 through December 31, 2004	Period from January 1 through March 2, 2004
	(In thousands)			
Current	$	$	$	$
Deferred	67,344	21,294	28,783	8,072
Total	$ 67,344	$ 21,294	$ 28,783	$ 8,072

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

	Post-Merger						Pre-Merger	
	Year Ending December 31, 2006		Year Ending December 31, 2005		Period from March 3, 2004 through December 31, 2004		Period from January 1 through March 2, 2004	
	(In thousands except percentages)							
Income before income taxes including change in accounting in 2003	$ 188,806		$ 61,775		$ 82,402		$ 22,898	
Income tax expense computed at	$ 66,081	35%	$ 21,621	35%	$ 28,841	35%	$ 8,014	35%

statutory rates												
State tax expense, net of the federal benefit		946	1%									
Other		317			(327)	(1)%		(58)			58	
Tax Expense	$	67,344	36%	$	21,294	34%	$	28,783	35%	$	8,072	35%

Federal income taxes of $1.6 million were paid by the Company for the 2004 Post-Merger period for alternative minimum tax liability, and no federal income taxes were paid by the Company in the years ended December 31, 2005 and 2006.

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

	December 31, 2006	December 31, 2005
	(In thousands)	
Deferred Tax Assets:		
Net operating loss carry forwards	$ 114,650	$ 45,171
Alternative minimum Tax Credit	1,606	1,606
Differences between book and tax basis of receivables		
Other comprehensive income-derivative instruments		22,332
Valuation allowance	(468)	(5,909)
Employee stock compensation	1,420	9,004
Other		671
Total net deferred tax assets	$ 117,208	$ 72,875
Current Deferred Tax Liabilities:		
Deferred gain	$ (9,158)	$
Other comprehensive income-derivative instruments	(19,119)	
Other	35	
Total current deferred tax liabilities	($ 28,242)	$ 0
Long Term Deferred Tax Liabilities:		
Other comprehensive income-derivative instruments	(6,019)	
Differences between book and tax basis properties	(372,771)	(72,744)
Total long term deferred tax liabilities	$ (378,790)	$ (72,744)
Total net deferred (liability) asset	$ (289,824)	$ 131

At December 31, 2006, the Company had federal and state net operating loss carryforwards of approximately $326.2 million and $6.9 million, respectively, which will expire in varying amounts between 2018 and 2024 and are subject to certain limitations on an annual basis. A valuation allowance has been established against state net operating losses where it is more likely than not that such losses will expire before they are utilized. The current portion of deferred tax liabilities is $26.9 million.

The Company has incurred changes of control as defined by the Internal Revenue Code Section 382 (Section 382). Accordingly, the rules of Section 382 will limit the utilization of our net operating losses. The limitation is determined by multiplying the value of the stock immediately before the ownership change by the applicable long-term exempt rate. It is estimated that $61.5 million of net operating losses will be subject to an annual limitation of approximately $4.0 million, and an estimated $176.4 million of net operating losses will be subject to an annual limitation of approximately $33.0 million. Any unused annual limitation may be carried over to later years. The amount of the limitation may under certain circumstances be increased by the built-in gains in assets held by us at the time of the change that are recognized in the five-year period after the change.

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Deferred tax assets relating to tax benefits of employee stock option grants have been reduced to reflect exercises in fiscal 2006. Some exercises resulted in tax deductions in excess of previously recorded benefits based on the option value at the time of grant (windfalls). Although these additional tax benefits or windfalls are reflected in net operating tax carryforwards pursuant to SFAS 123(R), the additional tax benefit associated with the windfall is not recognized until the deduction reduces taxes payable. Accordingly, since the tax benefit does not reduce our current taxes payable in fiscal 2006 due to net operating loss carryforwards, these windfall tax benefits are not reflected in our net operating losses in deferred tax assets for fiscal 2006. Windfalls included in net operating loss carryforwards but not reflected in deferred tax assets for fiscal 2006 are $7.9 million.

9. Segment Information

The Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) 131, Disclosures about Segments of an Enterprise and Related Information establishes standards for reporting information about operating segments. Operating segments are defined as components of an enterprise that engage in activities from which it may earn revenues and incur expenses. Separate financial information is available and this information is regularly evaluated by the chief decision maker for the purpose of allocating resources and assessing performance.

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

10. Quarterly Financial Information (Unaudited)

The following table presents Mariner s unaudited quarterly financial information for 2006 and 2005:

	2006 Quarter Ended			
	December 31	September 30	June 30	March 31
	(In thousands, except share data)			
Total revenues	$ 221,114	$ 190,466	$ 167,665	$ 80,260
Operating income	$ 78,955	$ 67,713	$ 57,787	$ 23,015
Income before income taxes	$ 66,197	$ 56,226	$ 49,260	$ 17,123
Provision for income taxes	22,959	19,836	18,556	5,993
Net income	$ 43,238	$ 36,390	$ 30,704	$ 11,130

Earnings per share:(1)								
Net income per share basic	$	0.51	$	0.43	$	0.36	$	0.22
Net income per share diluted	$	0.50	$	0.43	$	0.36	$	0.21
Weighted average shares outstanding basic		85,499,227		85,493,237		84,720,331		49,615,479
Weighted average shares outstanding diluted		85,750,225		85,581,108		85,027,561		51,844,610

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for the Period from March 3, 2004 through December 31, 2004 (Post-Merger),
and for the Period from January 1, 2004 through March 2, 2004 (Pre-Merger)

	2005 Quarter Ended			
	December 31	September 30	June 30	March 31
	(In thousands, except share data)			
Total revenues	$ 48,465	$ 43,662	$ 51,776	$ 55,807
Operating income	$ 10,471	$ 12,263	$ 18,070	$ 28,364
Income before income taxes	$ 7,798	$ 10,549	$ 16,382	$ 27,046
Provision for income taxes	2,880	3,606	5,537	9,271
Net income	$ 4,918	$ 6,943	$ 10,845	$ 17,775
Earnings per share:(1)				
Net income per share basic	$ 0.15	$ 0.21	$ 0.33	$ 0.58
Net income per share diluted	$ 0.14	$ 0.20	$ 0.32	$ 0.58
Weighted average shares outstanding basic(2)	33,348,130	33,348,130	33,348,130	30,558,130
Weighted average shares outstanding diluted	35,189,290	34,806,842	33,822,079	30,599,152

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

(2) Restated for the 1,380 to 29,748,130 stock split, effective March 3, 2005.

11. Supplemental Guarantor Information (Unaudited)

On April 24, 2006, the Company sold and issued to eligible purchasers $300 million aggregate principal amount of its 71/2% Senior Notes due 2013. The Notes are jointly and severally guaranteed on a senior unsecured basis by the Company s existing and future domestic subsidiaries (Subsidiary Guarantors). 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.

On March 2, 2006, a subsidiary of the Company completed a merger transaction with Forest Energy Resources, Inc. (the Forest Merger). Prior to the transaction, Forest transferred and contributed the assets of, and certain liabilities associated with, its Gulf of Mexico operations to Forest Energy Resources, Inc. Immediately prior to the Forest Merger, Forest distributed all of the outstanding shares of Forest Energy Resources, Inc. to Forest shareholders on a pro rata basis. Forest Energy Resources, Inc. then merged with a newly formed subsidiary of Mariner, became a new wholly owned subsidiary of Mariner and changed its name to MERI. The other two guarantors were formed on December 29, 2004, did not commence operations prior to January 1, 2005 and did not have material operations in 2005. The net equity of the guarantors was $0 as of December 31, 2004 and December 31, 2005, therefore, historical information prior to 2006 is not presented.

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MARINER ENERGY, INC.

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and for the Period from January 1, 2004 through March 2, 2004 (Pre-Merger)

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

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MARINER ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING BALANCE SHEET
December 31, 2006
(In thousands except share data)
(Unaudited)

	Parent Company	Subsidiary Guarantors	Eliminations	Consolidated Mariner Energy, Inc.
Current Assets:				
Cash and cash equivalents	$ 9,579	$	$	$ 9,579
Receivables, net	51,118	98,574		149,692
Insurance receivables	4,673	56,328		61,001
Derivative financial instruments	54,488			54,488
Prepaid seismic	19,468	1,367		20,835
Prepaid expenses and other	10,927	1,919		12,846
Total current assets	150,253	158,188		308,441
Property and Equipment:				
Oil and gas properties, full-cost method: Proved	922,385	1,422,656		2,345,041
Unproved, not subject to amortization	39,885	361		40,246
Total	962,270	1,423,017		2,385,287
Other property and equipment	13,444	68		13,512
Accumulated depreciation, depletion and amortization	(233,087)	(153,650)		(386,737)
Total property and equipment, net	742,627	1,269,435		2,012,062
Investment in subsidiaries	945,108		(945,108)	
Intercompany receivable	153,793		(153,793)	
Intercompany note receivable	176,200		(176,200)	
Restricted cash	31,830			31,830
Goodwill		288,504		288,504
Derivative financial instruments	17,153			17,153
Other Assets, Net of Amortization	22,163			22,163
TOTAL ASSETS	$ 2,239,127	$ 1,716,127	$ (1,275,101)	$ 2,680,153

Current Liabilities:				
Accounts payable	$ 1,822	$	$	$ 1,822
Accrued liabilities	61,779	13,101		74,880
Accrued capital costs	60,146	38,882		99,028
Deferred income tax	26,857			26,857
Abandonment liability	9,312	20,348		29,660
Accrued interest	7,355	125		7,480
Total current liabilities	167,271	72,456		239,727
Long-Term Liabilities:				
Abandonment liability	48,509	139,801		188,310
Deferred income tax	36,701	226,187		262,888
Intercompany payable		153,793	(153,793)	
Long term debt, bank credit facility	354,000			354,000
Long term debt, senior unsecured notes	300,000			300,000
Other long-term liabilities	30,055	2,582		32,637
Intercompany note payable		176,200	(176,200)	
Total long-term liabilities	769,265	698,563	(329,993)	1,137,835
Commitments and Contingencies Stockholders Equity:				
Preferred stock, $.0001 par value; 20,000,000 shares authorized, no shares issued and outstanding at December 31, 2006				
Common stock, $.0001 par value; 180,000,000 shares authorized, 86,375,840 shares issued and outstanding at December 31, 2006	9	5	(5)	9
Additional paid-in-capital	1,043,923	886,142	(886,142)	1,043,923
Accumulated other comprehensive income	43,097			43,097
Accumulated retained earnings	215,562	58,961	(58,961)	215,562
Total stockholders equity	1,302,591	945,108	(945,108)	1,302,591
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 2,239,127	$ 1,716,127	$ (1,275,101)	$ 2,680,153

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MARINER ENERGY, INC. AND SUBSIDIARIES

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

	Parent Company	Subsidiary Guarantors	Eliminations	Consolidated Mariner Energy, Inc.
Revenues:				
Oil sales	$ 141,862	$ 101,389	$	$ 243,251
Gas sales	185,175	227,792		412,967
Other revenues	3,287			3,287
Total revenues	330,324	329,181		659,505
Costs and Expenses:				
Lease operating expense	34,728	56,935		91,663
Severance and ad valorem taxes	7,294	1,704		8,998
Transportation expense	3,341	1,736		5,077
General and administrative expense	32,422	1,713		34,135
Depreciation, depletion and amortization	128,410	163,752		292,162
Total costs and expenses	206,195	225,840		432,035
OPERATING INCOME	124,129	103,341		227,470
Earnings of Affiliates	58,961		(58,961)	
Interest:				
Income	8,737	1	(7,753)	985
Expense, net of amounts capitalized	(35,714)	(11,688)	7,753	(39,649)
Income before taxes	156,113	91,654	(58,961)	188,806
Provision for income taxes	(34,651)	(32,693)		(67,344)
NET INCOME	$ 121,462	$ 58,961	$ (58,961)	$ 121,462

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MARINER ENERGY, INC. AND SUBSIDIARIES

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

	Parent Company	Subsidiary Guarantors	Consolidated Mariner Energy, Inc.
Operating Activities:			
Net income	$ 62,501	$ 58,961	$ 121,462
Adjustments to reconcile net loss to net cash provided by operating activities:			
Deferred income tax	18,409	48,935	67,344
Depreciation, depletion and amortization	131,554	163,738	295,292
Ineffectiveness of derivative instruments	(4,175)		(4,175)
Stock compensation	10,229		10,229
Changes in operating assets and liabilities:			
Receivables	32,991	(45,737)	(12,746)
Insurance receivables	(131)	(55,559)	(55,690)
Prepaid expenses and other	6,686	9,088	15,774
Other assets	(6,230)	9,082	2,852
Accounts payable and accrued liabilities	(60,609)	(109,210)	(169,819)
Net realized loss on derivative contracts acquired		6,638	6,638
Net cash provided by operating activities	191,225	85,936	277,161
Investing Activities:			
Acquisitions and additions to property and equipment	(330,298)	(212,283)	(542,581)
Property conveyances	33,829		33,829
Purchase price adjustment		(20,808)	(20,808)
Restricted cash designated for investment	(31,830)		(31,830)
Net cash used in investing activities	(328,299)	(233,091)	(561,390)
Financing Activities:			
Repayment of term note	(4,000)		(4,000)
Credit facility repayments, net	202,000		202,000
		(176,200)	(176,200)

Debt and working capital acquired from Forest Energy Resources, Inc.			
Proceeds from note offering	300,000		300,000
Repurchase of stock	(14,027)		(14,027)
Deferred offering costs	(12,601)		(12,601)
Net realized loss on derivative contracts acquired		(6,638)	(6,638)
Proceeds from exercise of stock options	718		718
Net activity in investments from subsidiaries	(329,993)	329,993	
Net cash provided by financing activities	142,097	147,155	289,252
Increase in Cash and Cash Equivalents	5,023		5,023
Cash and Cash Equivalents at Beginning of Period	4,556		4,556
Cash and Cash Equivalents at End of Period	$ 9,579	$	$ 9,579

12. Subsequent Events

None

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NOTES TO THE FINANCIAL STATEMENTS (Continued)
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and for the Period from January 1, 2004 through March 2, 2004 (Pre-Merger)

13. Oil and Gas Producing Activities and Capitalized Costs (Unaudited)

The results of operations from the Company s oil and gas producing activities were as follows (in thousands):

	Year Ending December 31,		
	2006	2005	2004
	(In thousands)		
Oil and gas sales	$ 656,218	$ 196,122	$ 214,187
Lease operating costs	(91,663)	(24,882)	(22,806)
Severance and ad valorem taxes	(8,998)	(5,000)	(2,678)
Transportation	(5,077)	(2,336)	(3,029)
Depreciation, depletion and amortization	(292,162)	(59,426)	(64,911)
Results of operations	$ 258,318	$ 104,478	$ 120,763

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

	As of December 31,		
	2006	2005	2004
	(In thousands)		
Unevaluated properties, not subject to amortization	$ 40,246	$ 40,176	$ 36,245
Properties subject to amortization	2,345,041	574,725	319,553
Capitalized costs	2,385,287	614,901	355,798
Accumulated depreciation, depletion and amortization	(384,948)	(109,183)	(52,680)
Net capitalized costs	$ 2,000,339	$ 505,718	$ 303,118

Costs incurred in property acquisition, exploration and development activities were as follows (in thousands, except per equivalent mcf amounts):

	Year Ending December 31,		
	2006	2005	2004

	(In thousands)		
Property acquisition costs			
Unproved properties	$ 47,655	$ 12,366	$ 4,844
Unproved properties Forest Acquisition	116,699		
Proved properties Forest Acquisition(1)	1,094,712		
Proved properties West Cameron 110/111	70,928		
Proved properties Other		52,503	4,863
Exploration costs	143,054	50,049	43,022
Development costs	323,843	121,685	88,626
Capitalized internal costs	14,471	6,016	7,334
Total costs incurred	$ 1,811,362	$ 242,619	$ 148,689
Depreciation, depletion and amortization rate per equivalent Mcf	$ 3.63	$ 2.04	$ 1.73

(1) In conjunction with the acquisition, includes asset retirement cost of approximately $165.2

The Company capitalizes interest and internal costs associated with exploration activities in progress. These capitalized costs were approximately 32%, 35% and 46% of the Company s gross general and

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MARINER ENERGY, INC.

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administrative expenses, excluding stock compensation expense for the years ended December 31, 2006, 2005 and 2004, respectively.

The following table summarizes costs related to unevaluated properties that have been excluded from amounts subject to amortization at December 31, 2006. There are no individually significant properties or significant development projects included in our unevaluated property balance. The Company regularly evaluates these costs to determine whether impairment has occurred. The majority of these costs are expected to be evaluated and included in the amortization base within three years.

	Period Incurred Year Ended December 31, 2006	2005	2004	Prior	Total at December 31, 2006
Unproved leasehold acquisition and geological and geophysical costs	$ 22,734	$ 7,619	$ 2,300	$ 4,460	$ 37,113
Unevaluated exploration and development costs	2,500	(23)	171		2,648
Capitalized interest	185	128	104	68	485
Total	$ 25,419	$ 7,724	$ 2,575	$ 4,528	$ 40,246

All of the excluded costs at December 31, 2006 relate to activities in the Gulf of Mexico.

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

Estimated proved net recoverable reserves as shown below include only those quantities that are expected to be commercially recoverable at prices and costs in effect at the balance sheet dates under existing regulatory practices and with conventional equipment and operating methods. Proved developed reserves represent only those reserves expected to be recovered through existing wells. Proved undeveloped reserves include those reserves expected to be recovered from new wells on undrilled acreage or from existing wells on which a relatively major expenditure is required for recompletion. Also included in the Company s proved undeveloped reserves as of December 31, 2006 were reserves expected to be recovered from wells for which certain drilling and completion operations had occurred as of that date, but for which significant future capital expenditures were required to bring the wells into commercial production.

Reserve estimates are inherently imprecise and may change as additional information becomes available. Furthermore, estimates of oil and gas reserves, of necessity, are projections based on engineering data, and there are uncertainties inherent in the interpretation of such data as well as in the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Accordingly, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of the future net cash flows expected therefrom prepared by different engineers or by the same engineers at different times may vary substantially. There also can be no assurance that the reserves set forth herein will ultimately be produced or that the proved undeveloped reserves set forth herein will be developed within the periods anticipated. It is likely that variances from the estimates will be material. In addition, the estimates of future net revenues from proved reserves of the Company and the present value thereof are based upon certain assumptions about future production levels, prices and costs that may not be correct when judged against actual subsequent experience. The Company emphasizes with respect to the estimates prepared by independent petroleum engineers that the discounted future net cash flows should not be

MARINER ENERGY, INC.

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construed as representative of the fair market value of the proved reserves owned by the Company since discounted future net cash flows are based upon projected cash flows which do not provide for changes in oil and natural gas prices from those in effect on the date indicated or for escalation of expenses and capital costs subsequent to such date. The meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based. Actual results will differ, and are likely to differ materially, from the results estimated.

ESTIMATED QUANTITIES OF PROVED RESERVES

	Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas Equivalent (MMcfe)
December 31, 2003	13,079	127,584	206,060
Revisions of previous estimates	1,249	19,797	27,291
Extensions, discoveries and other additions	2,225	28,334	41,684
Sale of reserves in place			
Production	(2,298)	(23,782)	(37,570)
December 31, 2004	14,255	151,933	237,465
Revisions of previous estimates	835	963	5,971
Extensions, discoveries and other additions	1,167	22,307	29,309
Purchases of reserves in place	7,181	50,837	93,923
Sales of reserves in place			
Production	(1,791)	(18,354)	(29,100)
December 31, 2005	21,647	207,686	337,568
Revisions of previous estimates	8,685	(58,055)	(5,947)
Extensions, discoveries and other additions	9,823	93,112	152,050
Purchases of reserves in place	12,410	244,741	319,201
Sales of reserves in place	(354)	(4,733)	(6,857)
Production	(4,075)	(56,064)	(80,512)
December 31, 2006	48,136	426,687	715,503

ESTIMATED QUANTITIES OF PROVED DEVELOPED RESERVES

	Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas Equivalent (MMcfe)
December 31, 2003	5,951	60,881	96,587
December 31, 2004	6,339	71,361	109,395
December 31, 2005	9,564	110,011	167,395
December 31, 2006	26,807	247,821	408,663

The following is a summary of a Standardized Measure of discounted net future cash flows related to the Company s proved oil and gas reserves. The information presented is based on a calculation of proved reserves using discounted cash flows based on year-end prices, costs and economic conditions and a 10% discount rate.

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The additions to proved reserves from new discoveries and extensions could vary significantly from year to year. Additionally, the impact of changes to reflect current prices and costs of reserves proved in prior years could also be significant. Accordingly, the information presented below should not be viewed as an estimate of the fair value of the Company s oil and gas properties, nor should it be considered indicative of any trends.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

	Year Ending December 31,		
	2006	**2005**	**2004**
	(In thousands)		
Future cash inflows	$ 4,858,420	$ 3,451,321	$ 1,601,240
Future production costs	(1,278,228)	(687,583)	(308,190)
Future development costs	(1,016,519)	(386,497)	(193,689)
Future income taxes	(528,135)	(695,921)	(285,701)
Future net cash flows	2,035,538	1,681,320	813,660
Discount of future net cash flows at 10% per annum	(795,677)	(774,755)	(319,278)
Standardized measure of discounted future net cash flows	$ 1,239,861	$ 906,565	$ 494,382

During recent years, there have been significant fluctuations in the prices paid for crude oil in the world markets and in the United States, including the posted prices paid by purchasers of the Company s crude oil. The Henry Hub cash prices of oil and gas at December 31, 2006, 2005 and 2004, used in the above table, were $61.06, $61.04 and $43.45 per Bbl, respectively, and $5.62, $10.05 and $6.15 per Mmbtu, respectively, and do not include the effect of hedging contracts in place at period end.

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

	Year Ending December 31,		
	2006	2005	2004
		(In thousands)	
Sales and transfers of oil and gas produced, net of production costs	$ (553,766)	$ (213,189)	$ (185,673)
Net changes in prices and production costs	(434,364)	425,317	27,767
Extensions and discoveries, net of future development and production costs	311,077	119,501	88,167
Purchases of reserves in place	568,576	189,782	14,738
Development costs during period and net change in development costs	245,050	46,632	44,417
Revision of previous quantity estimates	101,331	16,323	89,814
Sales of reserves in place	(10,642)		
Net change in income taxes	53,549	(201,647)	(27,634)
Accretion of discount before income taxes	90,656	49,438	41,816
Changes in production rates (timing) and other	(38,172)	(19,974)	(17,189)
Net change	$ 333,295	$ 412,183	$ 76,223

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

None

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

Evaluation of Disclosure Controls and Procedures

Mariner, under the supervision and with the participation of its management, including Mariner s principal executive officer and principal financial officer, evaluated the effectiveness of its disclosure controls and procedures, as such term is defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended, as of the end of the period covered by this Annual Report on Form 10-K. Based on that evaluation, our principal executive officer and principal financial officer concluded that Mariner s disclosure controls and procedures are effective.

Changes in Internal Controls Over Financial Reporting.

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

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

Not applicable.

PART III

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

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

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

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

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

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

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

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

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

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

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PART IV

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

(a)(1) *Financial Statements:*

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

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

None.

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

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

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Mariner Energy, Inc. has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 30, 2007.

Mariner Energy, Inc.

By: /s/ Scott D. Josey
Name: Scott D. Josey
Title: Chairman of the Board, Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of Mariner Energy, Inc. in the capacities indicated as of March 30, 2007:

Signature	Title
/s/ Scott D. Josey Scott D. Josey	Chairman of the Board, Chief Executive Officer and President (Principal Executive Officer)
/s/ John H. Karnes John H. Karnes	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)
/s/ Bernard Aronson Bernard Aronson	Director
/s/ Alan R. Crain, Jr. Alan R. Crain, Jr.	Director
/s/ Jonathan Ginns Jonathan Ginns	Director
/s/ John F. Greene John F. Greene	Director
/s/ H. Clayton Peterson H. Clayton Peterson	Director
/s/ John L. Schwager John L. Schwager	Director

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INDEX TO EXHIBITS

Exhibit Number	Description of Document
2.1*	Agreement and Plan of Merger dated as of September 9, 2005 among Forest Oil Corporation, SML Wellhead Corporation, Mariner Energy, Inc. and MEI Sub, Inc. (incorporated by reference to Exhibit 2.1 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
2.2*	Letter Agreement dated as of February 3, 2006 among Forest Oil Corporation, Forest Energy Resources, Inc., Mariner Energy, Inc. and MEI Sub, Inc. amending the transaction agreements (incorporated by reference to Exhibit 2.2 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
2.3*	Letter Agreement, dated as of February 28, 2006, among Forest Oil Corporation, Forest Energy Resources, Inc., Mariner Energy, Inc. and MEI Sub, Inc. amending the transaction agreements (incorporated by reference to Exhibit 2.1 to Mariner s Form 8-K filed on March 3, 2006).
2.4*	Letter Agreement, dated April 12, 2006, among Forest Oil Corporation, Mariner Energy Resources, Inc., and Mariner Energy, Inc. amending the transaction agreements (incorporated by reference to Exhibit 2.1 to Mariner s Form 8-K filed on April 13, 2006).
3.1*	Second Amended and Restated Certificate of Incorporation of Mariner Energy, Inc., as amended (incorporated by reference to Exhibit 3.1 to Mariner s Registration Statement on Form S-8 (File No. 333-132800) filed on March 29, 2006).
3.2*	Fourth Amended and Restated Bylaws of Mariner Energy, Inc. (incorporated by reference to Exhibit 3.2 to Mariner s Registration Statement on Form S-4 (File No. 333-129096) filed on October 18, 2005).
4.1*	Indenture, dated as of April 24, 2006, among Mariner Energy, Inc., the guarantors party thereto and Wells Fargo Bank, N.A., as trustee (incorporated by reference to Exhibit 4.1 to Mariner s Form 8-K filed on April 25, 2006).
4.2*	Exchange and Registration Rights Agreement, dated as of April 24, 2006, among Mariner Energy, Inc., the guarantors party thereto and the initial purchasers party thereto (incorporated by reference to Exhibit 4.2 to Mariner s Form 8-K filed on April 25, 2006).
4.3*	Amended and Restated Credit Agreement, dated as of March 2, 2006, among Mariner Energy, Inc. and Mariner Energy Resources, Inc., as Borrowers, the Lenders party thereto from time to time, as Lenders, and Union Bank of California, N.A., as Administrative Agent and as Issuing Lender (incorporated by reference to Exhibit 4.1 to Mariner s Form 8-K filed on March 3, 2006).
4.4*	Amendment No. 1 and Consent, dated as of April 7, 2006, among Mariner Energy, Inc. and Mariner Energy Resources, Inc., as Borrowers, the Lenders party thereto, and Union Bank of California, N.A., as Administrative Agent for such Lenders and as Issuing Lender for such Lenders (incorporated by reference to Exhibit 4.1 to Mariner s Form 8-K filed on April 13, 2006).
4.5*	Credit Agreement among Mariner Energy Inc., the Lenders party thereto and Union Bank of California, N.A., dated as of March 2, 2004 (incorporated by reference to Exhibit 4.5 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
4.6*	Amendment No. 1 and Assignment Agreement among Mariner Energy, Inc., Mariner Holdings, Inc., Mariner Energy LLC, the Lenders party thereto, and Union Bank of California, N.A., dated as of July 14, 2004 (incorporated by reference to Exhibit 4.6 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
4.7*	Waiver and Consent among Mariner Energy, Inc., Mariner Holdings, Inc., Mariner Energy LLC, the Union Bank of California, N.A. and the Lenders party thereto, dated December 29, 2004 (incorporated by reference to Exhibit 4.7 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).

4.8*	Amendment No. 2 and Consent among Mariner Energy, Inc., Mariner Holdings, Inc., Mariner Energy LLC, the Lenders party thereto, and the Union Bank of California, N.A., dated February 7, 2005 (incorporated by reference to Exhibit 4.8 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
4.9*	Amendment No. 3 and Consent among Mariner Energy, Inc., Mariner LP LLC, Mariner Energy Texas LP, the Lenders party thereto, and the Union Bank of California, N.A., dated March 3, 2005 (incorporated by reference to Exhibit 4.9 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).

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Exhibit Number	Description of Document
4.10*	Amendment No. 4 among Mariner Energy, Inc., Mariner LP LLC, Mariner Energy Texas LP, the Lenders party thereto, and Union Bank of California, N.A., dated as of July 14, 2005 (incorporated by reference to Exhibit 4.10 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
4.11*	Amendment No. 5 among Mariner Energy, Inc., Mariner LP LLC, Mariner Energy Texas LP, the Lenders party thereto, and Union Bank of California, N.A., dated as of August 5, 2005 (incorporated by reference to Exhibit 4.11 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
4.12*	Amendment No. 6, Waiver and Agreement among Mariner Energy, Inc., Mariner LP LLC, Mariner Energy Texas LP, the Lenders party thereto, and Union Bank of California, N.A., dated as of January 20, 2006 (incorporated by reference to Exhibit 4.12 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.1*	Purchase Agreement, dated as of April 19, 2006, among Mariner Energy, Inc., Mariner LP LLC, Mariner Energy Resources, Inc., Mariner Energy Texas LP and the initial purchasers party thereto (incorporated by reference to Exhibit 10.1 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.2*	Form of Indemnification Agreement between Mariner Energy, Inc. and each of its directors and officers (incorporated by reference to Exhibit 10.2 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.3	Mariner Energy, Inc. Second Amended and Restated Stock Incentive Plan, effective as of February 6, 2007.
10.4*	Form of Non-Qualified Stock Option Agreement, Mariner Energy, Inc. Amended and Restated Stock Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.5 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.5*	Form of Non-Qualified Stock Option Agreement, Mariner Energy, Inc. Amended and Restated Stock Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.6 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.6	Form of Restricted Stock Agreement (directors) under Mariner Energy, Inc. Second Amended and Restated Stock Incentive Plan.
10.7	Form of Restricted Stock Agreement (employee with employment agreement) under Mariner Energy, Inc. Second Amended and Restated Stock Incentive Plan.
10.8	Form of Restricted Stock Agreement (employee without employment agreement) under Mariner Energy, Inc. Second Amended and Restated Stock Incentive Plan.
10.9*	Mariner Energy, Inc. Equity Participation Plan, effective March 11, 2005 (incorporated by reference to Exhibit 10.10 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.10*	First Amendment to Mariner Energy, Inc. Equity Participation Plan, effective as of March 16, 2006 (incorporated by reference to Exhibit 10.11 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.11*	Form of Restricted Stock Agreement, Mariner Energy, Inc. Equity Participation Plan for employees with employment agreements (incorporated by reference to Exhibit 10.12 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.12*	Form of Restricted Stock Agreement, Mariner Energy, Inc. Equity Participation Plan for employees without employment agreements (incorporated by reference to Exhibit 10.13 to Mariner s Registration

	Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.13*	Form of Nonstatutory Stock Option Agreement for certain employees of Mariner Energy, Inc. or Mariner Energy Resources, Inc. who formerly held unvested options issued by Forest Oil Corporation (incorporated by reference to Exhibit 10.14 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.14*	Employment Agreement by and between Mariner Energy, Inc. and Scott D. Josey, dated February 7, 2005 (incorporated by reference to Exhibit 10.15 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).

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Exhibit Number	Description of Document
10.15*	Employment Agreement by and between Mariner Energy, Inc. and Dalton F. Polasek, dated February 7, 2005 (incorporated by reference to Exhibit 10.16 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.16*	Employment Agreement by and between Mariner Energy, Inc. and Michiel C. van den Bold, dated February 7, 2005 (incorporated by reference to Exhibit 10.17 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.17*	Amendment to Employment Agreement by and between Mariner Energy, Inc. and Michiel C. van den Bold, dated as of June 8, 2006 (incorporated by reference to Exhibit 10.18 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.18*	Second Amended and Restated Employment Agreement by and between Mariner Energy, Inc., Mariner Energy Resources, Inc. and Judd Hansen, dated June 8, 2006 (incorporated by reference to Exhibit 10.19 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.19*	Employment Agreement by and between Mariner Energy, Inc. and Teresa Bushman, dated February 7, 2005 (incorporated by reference to Exhibit 10.20 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.20*	Amendment to Employment Agreement by and between Mariner Energy, Inc. and Teresa G. Bushman, dated as of June 8, 2006 (incorporated by reference to Exhibit 10.21 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.21*	Employment Agreement by and between Mariner Energy, Inc. and Ricky G. Lester, dated February 7, 2005 (incorporated by reference to Exhibit 10.22 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.22*	Consulting Agreement between Mariner Energy, Inc. and Ricky G. Lester, dated effective August 16, 2006 (incorporated by reference to Exhibit 10.23 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.23*	Registration Rights Agreement among Mariner Energy, Inc. and each of the investors identified therein, dated March 11, 2005 (incorporated by reference to Exhibit 10.24 to Mariner s Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.24*	Amendment No. 2, dated as of October 13, 2006, among Mariner Energy, Inc. and Mariner Energy Resources, Inc., as Borrowers, the Lenders party thereto, and Union Bank of California, N.A., as Administrative Agent for such Lenders and as Issuing Lender for such Lenders (incorporated by Reference to Exhibit 4.1 to Mariner s current report on Form 8-K filed on October 18, 2006).
10.25*	Employment Agreement, by and between Mariner Energy, Inc. and John H. Karnes, dated as of October 16, 2006 (incorporated by reference to Exhibit 10.1 to Mariner s current report on Form 8-K filed on October 18, 2006).
12	Statement regarding Computation of Ratio of Earnings to Fixed Charges.
21	List of subsidiaries.
23.1	Consent of Deloitte & Touche LLP.
23.2	Consent of Ryder Scott Company, L.P.
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Incorporated by reference as indicated.

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