MARINER ENERGY INC
Form 10-K
March 31, 2006

Table of Contents

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, 2005

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 o No þ

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, 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 voting stock held by nonaffiliates of the registrant as of March 17, 2006, based on the closing price of the common stock on the New York Stock Exchange on such date ($20.05 per share), was $1,621,766,425. The number of shares of common stock of the registrant issued and outstanding on March 17, 2006 was 86,100,994.

TABLE OF CONTENTS

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, will, estimate, project, predict, believe, expect, anticipate, potential, plan, goal or other words that convey the uncertainty of futu outcomes. The forward-looking statements in this Annual Report speak only as of the date of this Annual Report; we disclaim any obligation to update these statements unless required by law, and we caution you not to rely on them unduly. We have based these forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. We disclose important factors that could cause our actual results to differ materially from our expectations described in 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;

Table of Contents

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 disasters such as fires, floods and other 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;

our merger with Forest Energy Resources, including strategic plans, expectations and objectives for future operations, and the realization of expected benefits from the transaction; and

disruption from the merger with Forest Energy Resources making it more difficult to manage our business.

Table of Contents

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. References to pro forma and on a pro forma basis mean on a pro forma basis, giving effect to our merger with Forest Energy Resources, Inc. as if it had been consummated at the applicable date or at the beginning of the period referenced. The merger was consummated on March 2, 2006. The unaudited pro forma information contained in this Annual Report has been derived from the historical consolidated financial statements of Mariner 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 merger occurred in the past or the future financial results that Mariner will achieve after the merger.

Items 1 and 2. *Business and Properties.*

General

We are an independent oil and gas exploration, development and production company with principal operations in the Gulf of Mexico, both shelf and deepwater, and in the Permian Basin in West Texas. Our management has significant expertise and a successful operating track record in these areas. In the three-year period ended December 31, 2005, we added approximately 280 Bcfe of proved reserves and produced approximately 100 Bcfe, while deploying approximately $475 million of capital on acquisitions, exploration and development.

Our primary operating strategy is to generate high-quality exploration and development projects, which enables us to add value through the drill bit. Our expertise in project generation also facilitates our participation in high-quality projects generated by other operators. We will also pursue acquisitions of producing assets that have the potential to provide acceptable risk-adjusted rates of return and further reserve additions through exploration, exploitation, and development opportunities. We target a balanced exposure to development, exploitation and exploration opportunities, both offshore and onshore and seek to maintain a moderate risk profile.

On March 2, 2006, we completed a merger transaction with Forest Energy Resources, Inc., which we refer to as Forest Energy Resources. As a result of this merger, we acquired the offshore Gulf of Mexico operations of Forest Oil Corporation (NYSE: FST), which we refer to as the Forest Gulf of Mexico operations. We refer to Forest Oil Corporation as Forest.

As of December 31, 2005, we had 338 Bcfe of estimated proved reserves, of which approximately 62% were natural gas and 38% were oil and condensate. Pro forma for the merger transaction, as of December 31, 2005, we had 644 Bcfe of estimated proved reserves, of which approximately 68% were natural gas and 32% were oil and condensate. Our production for 2005 was approximately 29 Bcfe, or 80 MMcfe per day on average, and 95 Bcfe, or 260 MMcfe per day on average, pro forma for the merger, including the negative impact of approximately 15-20 Bcfe of production lost due to Hurricanes Katrina and Rita.

The following table sets forth certain information with respect to our estimated proved reserves, production and acreage by geographic area as of December 31, 2005. Reserve volumes and values were determined under the method prescribed by the SEC which requires the application of period-end prices and 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. The reserve information for

Table of Contents

Mariner as of December 31, 2005 is based on estimates made in a reserve report prepared by Ryder Scott Company, L.P., independent petroleum engineers (Ryder Scott).

Geographic Area	Estimated Proved Reserve Quantities Oil (MMbbls)	Natural Gas (Bcf)	Total (Bcfe)	Total Net Acreage	Production for Year Ended December 31, 2005 (Natural Gas Equivalent (Bcfe))
West Texas Permian Basin	16.7	105.5	205.5	31,199	6.6
Gulf of Mexico Deepwater(1)	4.7	83.2	111.1	185,271	11.8
Gulf of Mexico Shelf(2)	0.3	19.0	21.0	124,180	10.7
Total	21.7	207.7	337.6	340,650	29.1
Proved Developed Reserves	9.6	110.0	167.4		

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

(2) Shelf refers to water depths less than 1,300 feet and includes an insignificant amount of Gulf Coast onshore properties.

The following table sets forth certain information with respect to our pro forma estimated proved reserves, production and acreage by geographic area as of December 31, 2005. The reserve information as of December 31, 2005 for the Forest Gulf of Mexico operations is based on estimates made by internal staff engineers of Forest, which estimates were audited by Ryder Scott. This information is presented on a pro forma basis, giving effect to our merger with Forest Energy Resources as though it had been consummated on December 31, 2005. We consummated the merger on March 2, 2006.

Geographic Area	Pro Forma Estimated Proved Reserve Quantities Oil (MMbbls)	Natural Gas (Bcf)	Total (Bcfe)	Pro Forma Total Net Acreage	Pro Forma Production for Year Ended December 31, 2005 (Natural Gas Equivalent (Bcfe))
West Texas Permian Basin	16.7	105.5	205.5	31,199	6.6
Gulf of Mexico Deepwater(1)	4.8	95.7	124.5	241,320	14.0
Gulf of Mexico Shelf(2)	12.7	237.6	313.7	652,086	74.3
Total	34.2	438.8	643.7	924,605	94.9
Proved Developed Reserves	18.4	252.1	362.3		

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

(2) Shelf refers to water depths less than 1,300 feet and includes an insignificant amount of Gulf Coast onshore properties.

We were incorporated in August 1983 as a Delaware corporation. We have three subsidiaries, Mariner Energy Resources, Inc., a Delaware corporation, Mariner LP LLC, a Delaware limited liability company, and Mariner Energy Texas LP, a Delaware limited partnership. Our principal executive office is located at One BriarLake Plaza, Suite 2000, 2000 West Sam Houston Parkway South, Houston, Texas 77042. Our telephone number is (713) 954-5500.

Our Strategy

The principal elements of our operating strategy include:

Generate and pursue high-quality prospects. We expect to continue our strategy of growth through the drill bit by continuing to identify and develop high-impact shelf, deep shelf and deepwater projects in the Gulf of Mexico. Our technical team has significant expertise and a successful track record of achieving growth by generating prospects internally, and selectively participating in prospects generated by other operators. We

Table of Contents

believe the Gulf of Mexico is an area that offers substantial growth opportunities, and our acquisition of the Forest Gulf of Mexico operations has more than doubled our existing undeveloped acreage position in the Gulf, providing numerous additional exploration, exploitation and development opportunities.

Maintain a moderate risk profile. We seek to manage our risk profile by targeting a balanced exposure to development, exploitation and exploration opportunities. For example, we intend to continue to develop and seek to expand our West Texas assets, which contribute stable cash flows and long-lived reserves to our portfolio as a counterbalance to our high-impact, high-production Gulf of Mexico assets. We also seek to 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 industry partners in which they agree to pay a disproportionate share of drilling costs and to 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 more opportunities to participate in these prospects in the future, as a result of the scale and increased cash flow from the Forest Gulf of Mexico operations.

Pursue opportunistic acquisitions. Until 2005, we grew our reserves primarily through the drill bit. However, in 2005 we added significant proved reserves through onshore acquisitions in West Texas. As part of our growth strategy, we will seek to continue to acquire producing assets that have the potential to provide acceptable risk-adjusted rates of return and further reserve additions through exploration, exploitation and development opportunities.

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, including shelf, deep shelf and deepwater, and the Permian Basin in West Texas. Our asset 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 the Forest Gulf of Mexico operations more than doubled our existing undeveloped acreage position in the Gulf of Mexico to approximately 450,000 net acres and increased our total net leasehold acreage offshore to nearly one million acres, providing numerous exploration, exploitation and development opportunities. We currently have an inventory of more than 1,000 drilling locations in West Texas, which we believe would require at least seven years to drill. Our 110 Bcfe of undeveloped estimated proved reserves in West Texas includes 441 locations.

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, 2005, we deployed approximately $475 million of capital on acquisitions, exploration and development, while adding approximately 280 Bcfe of proved reserves and producing approximately 100 Bcfe.

Our depth of operating experience. Our team of 36 geoscientists, engineers, geologists and other technical professionals and landmen average more than 20 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 technical 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 seismic data from multiple, recent vintage 3-D seismic databases covering more than 6,600 blocks in the Gulf of Mexico that we intend to continue to use to develop prospects on acreage being evaluated for leasing and to develop and further refine prospects on our expanded acreage position. 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 more costly platforms and top side facilities that typically require longer lead times. We believe the use of subsea tiebacks in appropriate projects enables us to bring production online more quickly, makes target prospects more profitable and allows us to exploit reserves that may otherwise be considered non-commercial because of the high cost of infrastructure. In the Gulf of Mexico, in the three years ended December 31, 2005, we were directly involved in 14 projects (five of which we operated) utilizing subsea tieback systems in water depths ranging from 475 feet to more than 6,700 feet.

Recent Developments

Forest Gulf of Mexico Merger

On March 2, 2006, we completed a merger transaction with Forest Energy Resources. Prior to the consummation of the merger, Forest transferred and contributed the assets and certain liabilities associated with its offshore Gulf of Mexico operations to Forest Energy Resources. Immediately prior to the 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, and became a new wholly owned subsidiary of Mariner. Immediately following the 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.

Forest Energy Resources had approximately 306 Bcfe of estimated proved reserves as of December 31, 2005, of which approximately 76% were natural gas and 24% were oil and condensate. The reserves and operations acquired from Forest are concentrated in the shelf and deep shelf of the Gulf of Mexico and represent a significant addition to Mariner s asset portfolio in those areas of operation.

We believe our acquisition of the Forest Gulf of Mexico operations and the scale they bring to our business has further moderated our risk profile, provided many exploration, exploitation and development opportunities, enhanced our ability to participate in prospects generated by other operators, and added a significant cash flow generating resource that has improved our ability to compete effectively in the Gulf of Mexico and to provide funding for exploration and acquisitions. We believe we are well-positioned to optimize the Forest Energy Resources assets through aggressive and timely exploitation.

Hurricanes Katrina and Rita

Our operations were adversely affected by one of the most active and severe hurricane seasons in recorded history. As of December 31, 2005 we had approximately 5 MMcfe per day of net production shut-in as a result of Hurricanes Katrina and Rita, and approximately 56 MMcfe per day on a pro forma basis. We estimate that as of March 15, 2006, approximately 42 MMcfe per day remains shut in. Additionally, we experienced delays in the startup of four of our deepwater projects primarily as a result of Hurricane Katrina. Two of the projects have commenced production, and two are anticipated to commence production in the second quarter of 2006. For the period September through December 2005, we estimate that approximately 6-8 Bcfe of production (approximately 15-20 Bcfe on a pro forma basis) was deferred because of the hurricanes. We also estimate that an additional 8 Bcfe of pro forma production will be deferred in 2006 before repairs to offshore and onshore infrastructure are fully completed, allowing return of full production from our fields. However, the actual volumes deferred in 2006 will vary based on circumstances beyond our control, including the timing of repairs to both onshore and offshore platforms, pipelines and facilities, the actions of operators on our fields, availability of service equipment, and weather.

We estimate the costs to repair damage caused by the hurricanes to our platforms and facilities will total approximately $50 million. However, until we are able to complete all the repair work this estimate is subject to significant variance. For the insurance period covering the 2005 hurricane activity, we carried a $3 million annual deductible and a $0.5 million single occurrence deductible for the Mariner assets. Insurance covering the Forest Gulf of Mexico properties carried a $5 million deductible for each occurrence. Until the repairs are completed and we submit costs to our insurance underwriters for review, the full extent of our insurance recoveries and the resulting net cost to us for Hurricanes Katrina and Rita will be unknown. However, we expect the total costs not covered by the combined insurance policies to be less than $15 million.

Table of Contents

Insurance

Effective March 2, 2006, Mariner has been accepted as a member of OIL Insurance, Ltd. or OIL, an industry insurance cooperative, through which the assets of both Mariner and the Forest Gulf of Mexico operations are insured. The coverage contains a $5 million annual per-occurrence deductible for the combined assets and a $250 million per-occurrence loss limit. However, if a single event causes losses to OIL insured assets in excess of $1 billion in the aggregate (effective June 1, 2006, such amount will be reduced to $500 million), amounts covered for such losses will be reduced on a pro rata basis among OIL members. Pending review of our insurance program, we have maintained our commercially underwritten insurance coverage for the pre-merger Mariner assets, which coverage expires on September 30, 2006. This coverage contains a $3 million annual deductible and a $500,000 occurrence deductible, $150 million of aggregate loss limits, and limited business interruption coverage. While the coverage remains in effect, it will be primary to the OIL coverage for the pre-merger Mariner assets.

Credit Agreement

On March 2, 2006, Mariner and Mariner Energy Resources, Inc. entered into a $500 million senior secured revolving credit facility, and an additional $40 million senior secured letter of credit facility. The revolving credit facility will mature on March 2, 2010, and the $40 million letter of credit facility will mature on March 2, 2009. We used borrowings under the revolving credit facility to facilitate the merger and to retire existing debt, and we may use borrowings in the future for general corporate purposes. The $40 million letter of credit facility has been used to obtain a letter of credit in favor of Forest to secure our performance of our obligations under an existing drill-to-earn program. The outstanding principal balance of loans under the revolving credit facility may not exceed the borrowing base, which initially has been set at $400 million. If the borrowing base falls below the outstanding balance under the revolving credit facility, we 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.

Summary Reserve and Operating Data

The following tables present certain information with respect to our estimated proved oil and natural gas reserves at year end and operating data for the periods presented. The 2005 information is also presented on a pro forma basis, giving effect to our merger with Forest Energy Resources as though it had been consummated on January 1, 2005. We consummated the merger on March 2, 2006.

Estimated Proved Reserves

The reserve information in the table below for Mariner is based on estimates made in reserve reports prepared by Ryder Scott. The reserve information as of December 31, 2005 for the Forest Gulf of Mexico operations is based on estimates made by internal staff engineers at Forest, which estimates were audited by Ryder Scott. Accordingly, the pro forma reserve information presented below includes both reserves that were estimated by Ryder Scott and reserves that were estimated by internal staff engineers at Forest and audited by Ryder Scott.

Table of Contents

	Pro Forma Year Ended December 31, 2005	As of the Year Ended December, 31 2005	2004	2003
Estimated proved oil and natural gas reserves:				
Natural gas reserves (Bcf)	438.8	207.7	151.9	127.6
Oil (MMbbls)	34.1	21.6	14.3	13.1
Total proved oil and natural gas reserves (Bcfe)	643.7	337.6	237.5	206.1
Total proved developed reserves (Bcfe)	362.3	167.4	109.4	96.6
PV10 value ($ in millions):				
Proved developed reserves	$ 2,023.4	$ 849.6	$ 335.4	$ 314.6
Proved undeveloped reserves	1,028.4	432.2	332.6	218.9
Total PV10 value	3,051.8	1,281.8	668.0	533.5
Standardized measure	2,201.7	906.6	494.4	418.2
Prices used in calculating end of period proved reserve measures (excluding effects of hedging)(1):				
Natural gas ($/MMBtu)	$ 10.05	$ 10.05	$ 6.15	$ 5.96
Oil ($/bbl)	61.04	61.04	43.45	32.52

(1) Our PV10 values have been calculated using NYMEX prices at the end of the relevant period, as adjusted for our price differentials. Please read note 11 to the Mariner financial statements contained in Item 8 of this Annual Report.

Table of Contents

Operating Data

The following table presents certain information with respect to our production and operating data for the periods presented.

	Pro Forma Year Ended December 31, 2005	Year Ended December 31, 2005	2004	2003
Production:				
Natural gas (Bcf)	67.5	18.4	23.8	23.8
Oil (Mbbls)	4.6	1.8	2.3	1.6
Total natural gas equivalent (Bcfe)	94.9	29.1	37.6	33.4
Average daily natural gas equivalent (MMcfe)	260.0	79.7	103.0	91.5
Average realized sales price per unit (excluding the effects of hedging):				
Natural gas ($/Mcf)	$ 8.04	$ 8.33	$ 6.12	$ 5.43
Oil ($/bbl)	48.86	51.66	38.52	26.85
Total natural gas equivalent ($/Mcfe)	8.07	8.43	6.23	5.15
Average realized sales price per unit (including the effects of hedging):				
Natural gas ($/Mcf)	$ 6.40	$ 6.66	$ 5.80	$ 4.40
Oil ($/bbl)	34.18	41.23	33.17	23.74
Total natural gas equivalent ($/Mcfe)	6.20	6.74	5.70	4.27
Expenses ($/Mcfe):				
Lease operating expenses	$ 1.17	$ 1.03	$ 0.68	$ 0.74
Transportation	0.06	0.08	0.08	0.19
General and administrative, net (1)		1.27	0.23	0.24
Depreciation, depletion and amortization (excluding impairments) (2)	3.47	2.04	1.73	1.45

(1) Net of overhead reimbursements received from other working interest owners and amounts capitalized under the full cost accounting method. Includes non-cash stock compensation expense of $25.7 million in 2005. General and administrative expenses, net, are not included in pro forma 2005 because accounts of such costs were not historically maintained for the Forest Gulf of Mexico operations as a separate business unit. We believe the overhead costs associated with the Forest Gulf of Mexico operations in 2006 will approximate $6.4 million, net of capitalized amounts.

(2) Pro forma depreciation, depletion and amortization gives effect to the acquisition of the Forest Gulf of Mexico operations and a preliminary estimate of their step-up in basis using the unit of production method under the full cost method of accounting.

Table of Contents

Properties

We currently own oil and gas properties, producing and non-producing, onshore in Texas and offshore in the Gulf of Mexico, primarily in federal waters. Our largest properties (including the largest properties we acquired in our merger with Forest Energy Resources), based on the present value of estimated future net proved reserves as of December 31, 2005, are shown in the following table.

	Operator	Mariner Working Interest(%)	Approximate Water Depth (Feet)	Gross Producing Wells(1)	Date Production Commenced/ Expected	Estimated Proved Reserves (Bcfe)	PV10 Value ($ In Millions)(2)	Sta N N
as Permian Basin:								
nit	Mariner	66.5(3)	Onshore	246	*	120.7	$ 367.0	
Spraberry Properties	Tamarack	35.0(4)	Onshore	187	*	67.8	103.2	
exico Deepwater:								
i Canyon 296/252	Dominion	22.5	5,200	0(5)	First Quarter 2006	22.5	161.4	
alley 426 (Bass Lite)	Mariner	38.75(6)	6,500	0	2008	32.3	137.9	
oll 917/961/962 n)	Mariner(6)	15.0	4,700	2	Fourth Quarter 2005	12.9	101.7	
i Canyon 718	Mariner	51.0	2,830	0	1999	9.0	69.3	
yon 646 (Daniel	W&T Offshore	40.0	4,300	0	2008	16.4	61.8	
yon 516 (Yosemite)	ENI	44.0	3,900	1	2002	7.8	53.9	
s 420**	Noble	50.0	2,560	1	2002	13.4	75.8	
exico Shelf:								
ron 14**	Mariner	50.0	25	2	*	15.2	91.5	
and 292**	Mariner	45.0	195	8	*	8.2	54.7	
and 53**	Mariner	50.0(9)	40	4	*	10.4	78.1	
d 116**	Mariner	98.9(10)	45	2	*	9.7	52.7	
26**	Mariner	100.0	10	1	*	7.2	41.5	
sh Island 18**	Mariner	100.0	75	1	1993	9.5	50.6	
24-NCOC**	Mariner	100.0	10	15	*	23.5	103.8	
14**	Mariner	100.0	20	16	*	32.8	177.7	
380**	Mariner	55.0-100.0	320	5	*	11.4	59.2	
eron 110**	BP/Amoco	37.5	40	5	*	9.0	51.9	
eron 111/112**	Mariner	55.0	43	1	2004	6.5	49.8	
eron 205**	Mariner	100.0	50	1	*	5.7	41.9	
operties				93		48.2	225.6	
operties (Forest pro				344		143.6	840.8	
				935		643.7	$ 3,051.8	$

* Production commenced twenty years or more years ago.

** Pro forma properties from Forest Gulf of Mexico operations.

(1) Wells producing or capable of producing as of December 31, 2005.

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

(3) Mariner operates the field and owns working interests in individual wells ranging from approximately 33% to 84%.

(4) Mariner owns an approximate average 35% working interest in producing wells. Upon completion of approximately 150 additional wells, Mariner will obtain an approximate 35% working interest in the entire committed acreage.

(5) The Rigel Prospect commenced production with one well in the first quarter of 2006.

Table of Contents

(6) Since December 31, 2005, Mariner has exercised a preferential right with respect to the property, thereby increasing its working interest to 42.19%.

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

(8) This field was shut-in in April 2004 pending the drilling of a new well and installation of an extension to the existing infield flowline and umbilical. As a result, as of December 31, 2005, 8.9 Bcfe of our net proved reserves attributable to this project were classified as proved behind pipe reserves. We expect production from Pluto to recommence in the second quarter of 2006.

(9) Mariner operates the field and owns working interests in individual wells ranging from approximately 50% to 100%.

(10) Mariner operates the field and owns working interests in individual wells ranging from approximately 98.9% to 100%.

West Texas Permian Basin

Aldwell Unit. We operate and own working interests in individual wells ranging from 33% to 84% (with an average working interest of approximately 66.5%), in the 18,500-acre Aldwell Unit. The field is located in the heart of the Spraberry geologic trend southeast of Midland, Texas, and has produced oil and gas since 1949. We began our recent redevelopment of the Aldwell Unit by drilling eight wells in the fourth quarter of 2002, 43 wells in 2003, 54 wells in 2004 and 65 wells in 2005. As of December 31, 2005, there were a total of 249 wells producing or capable of producing in the field.

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

Tamarack/Spraberry Properties. Effective in October 2005, we entered into an agreement covering approximately 33,000 acres in West Texas, pursuant to which, upon closing, we acquired an approximate 35% working interest in approximately 200 existing producing wells effective November 1, 2005, and committed to drill an additional 150 wells within a four year period, while funding $36.5 million of our partner s share of drilling costs for such 150-well drilling program. We will obtain an assignment of an approximate 35% working interest in the entire committed acreage upon completion of the 150-well program. During 2005, we drilled 13 new wells under this agreement.

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

In December 2005, we acquired an interest in approximately 5,500 acres with an average 84% working interest and 64% net revenue interest in the Spraberry trend area 5-10 miles southwest of our Aldwell Unit. The purchase price was $5.5 million with an effective date of August 1, 2005 and included 34 producing wells with the potential to drill 68 40-acre wells.

During 2005, our aggregate net capital expenditures for the West Texas Permian Basin were approximately $86 million, and we added 97.2 Bcfe of proved reserves, while producing 6.6 Bcfe.

Table of Contents

Gulf of Mexico Deepwater

Mississippi Canyon 296/252 (Rigel). Mariner generated the Rigel prospect and acquired its interest in Mississippi Canyon block 296 at a federal offshore Gulf lease sale in March 1999. Our working interest in Rigel is 22.5%. The project is located approximately 130 miles southeast of New Orleans, Louisiana, in water depth of approximately 5,200 feet. A successful exploration well was drilled on the prospect in 1999. In September 2003, a successful appraisal well was drilled. This project was developed with a single subsea well tied back 12 miles to an existing subsea manifold that is connected to an existing platform. Production commenced in the first quarter of 2006.

Atwater Valley 426 (Bass Lite). The Bass Lite project is located in Atwater Valley blocks 380, 381, 382, 425 and 426, approximately 200 miles southeast of New Orleans in approximately 6,500 feet of water. We have a 42.19% working interest and have been designated operator of this project. Negotiations continue with third party host facilities and partners to finalize development plans.

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

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

Green Canyon 646 (Daniel Boone). Mariner generated the Daniel Boone prospect and acquired a 100% working interest in Daniel Boone at a Gulf of Mexico federal offshore lease sale in July 1998. The project is located in approximately 4,300 feet of water approximately 165 miles south of New Orleans, Louisiana. Subsequent to the acquisition, Mariner entered into a farmout agreement retaining a 40% working interest in the project. A successful exploration well was drilled in 2003. The project will be developed as a subsea tieback to existing infrastructure and is expected to commence production in 2008.

Green Canyon 516 (Yosemite). Mariner generated the Yosemite prospect and acquired the prospect at a Gulf of Mexico federal lease sale in 1998. We have a 44% working interest in this project located in approximately 3,900 feet of water, approximately 150 miles southeast of New Orleans. In 2001, we drilled an exploratory well on the prospect, and in February 2002 commenced production via a 16-mile subsea tieback to an existing platform which also handles production from the King Kong field in Green Canyon 472/473, in which we own a 50% interest.

East Breaks 420. Forest leased three blocks located on this property in 1996, and an additional block in 1998. Forest subsequently sold a 50% working interest to Noble. The property is located in approximately 2,560 feet of water, approximately 174 miles southwest of Cameron, Louisiana. A successful well was drilled in 2001. The project was completed with a subsea tieback to existing infrastructure. Production commenced in June 2002. The property was acquired by Mariner on March 2, 2006 as part of its merger with Forest Energy Resources.

Table of Contents

Other Projects and Activity. In late 2004, we participated in a successful exploratory well in our North Black Widow prospect in Ewing Banks 921, which is located approximately 125 miles south of New Orleans in approximately 1,700 feet of water. We have a 35% working interest in this project. A development plan for the North Black Widow prospect has been approved and the operator of this project currently anticipates production from this project to begin in the second quarter of 2006.

In June 2005, we increased our working interest in the LaSalle project (East Breaks 558, 513, and 514) to 100% by acquiring the remaining working interest owned by a third party for $1.5 million. The blocks contain an undeveloped discovery, as well as exploration potential. We have executed a participation agreement with Kerr McGee to jointly develop the LaSalle project and Kerr McGee s nearby NW Nansen exploitation project (East Breaks 602). Under the proposed participation agreement, Mariner owns a 33% working interest in the NW Nansen project and a 50% working interest in the LaSalle project. The LaSalle and NW Nansen projects are located approximately 150 miles south of Galveston, Texas in water depths of approximately 3,100 and 3,300 feet, respectively, Mariner and Kerr McGee have committed to drilling four wells, three on East Breaks 602 and one on East Breaks 558. As of March 20, 2006, two discovery wells have been drilled, one is currently drilling, and the fourth will commence immediately after the current well. First production is expected by the first quarter of 2008, with related completion and facility capital being spent in 2006 and 2007. As of December 31, 2005, we had booked no proved reserves to this project.

At the King Kong/Yosemite field (Green Canyon blocks 516, 472, and 473) we have planned, in conjunction with the operator, a two-well drilling program to exploit potential new reserve additions. We drilled one development well on block 473 in the first quarter of 2006, and anticipate drilling an exploration well on block 472 in the second quarter of 2006. We own a 50% working interest in the King Kong field in Green Canyon 472 and 473 and a 44% working interest in the Yosemite field in Green Canyon 516. The development well on Green Canyon 473 has been drilled and completion operations are currently underway. Initial production is anticipated in the second quarter of 2006.

Gulf of Mexico Shelf

Each of the following Gulf of Mexico shelf properties was acquired by Mariner on March 2, 2006 as part of its merger with Forest Energy Resources.

East Cameron 14. Forest acquired a 50% working interest in this property through Forest s acquisition of Forcenergy Inc in 2000. As of March 2, 2006, Mariner operates the property and owns a 50% working interest. This property is located in approximately 25 feet of water, approximately 30 miles southeast of Cameron, Louisiana.

Eugene Island 292. This property was installed in 1967, with first production commencing in 1970. As of March 2, 2006, Mariner operates the property and owns a 45% working interest in this field. The property consists of a hub for the complex including six platforms. The property is located in approximately 195 feet of water, approximately 140 miles southeast of Cameron, Louisiana.

Eugene Island 53. The shallow rights to this property were acquired in 1993 from Sandefer Offshore Operating. Subsequently, the deep rights were acquired from Pennzoil in 1995 and 1997. As of March 2, 2006, Mariner operates the property and owns between 50% and 100% working interests in various wells in the field. The property is located in approximately 40 feet of water, approximately 111 miles southeast of Cameron, Louisiana.

High Island 116. This property was acquired in 1993 from Arco. In 2000 Forest purchased the remaining working interests in this property and, as of March 2, 2006, Mariner operates the property and owns a 100% working interest. The property is located in approximately 45 feet of water, approximately 49 miles southwest of Cameron, Louisiana.

Ship Shoal 26. This property was acquired through Forest s acquisition of Forcenergy Inc in 2000. As of March 2, 2006, Mariner operates the property and owns a 100% working interest in the property. The property is located in approximately 10 feet of water, approximately 97 miles southwest of New Orleans, Louisiana.

South Marsh Island 18. This property was acquired through Forest s acquisition of Forcenergy Inc in 2000. Forest subsequently sold a 50% working interest in the property to Unocal in 2001. As part of an acquisition of properties from Union Oil of California (Unocal) in 2003, Forest repurchased Unocal s 50% working interest, and, as of March 2, 2006, Mariner operates the property and holds a 100% working interest. The property is located in approximately 75 feet of water, approximately 101 miles southeast of Cameron, Louisiana.

South Pass 24 NCOC. This property was acquired through Forest s acquisition of Forcenergy Inc in 2000. Forest acquired the remaining working interest (approximately 25%) from Pogo in 2004. As of March 2, 2006, Mariner operates the property and currently holds a 100% working interest. The property is located approximately 82 miles south of New Orleans, Louisiana in approximately 10 feet of water.

Vermillion 14. A 50% working interest in this property was acquired from Unocal in 2003. In 2004, Forest acquired BP s 50% working interest and, as of March 2, 2006, Mariner operates the property and owns a 100% working interest. The property is located in approximately 20 feet of water, approximately 63 miles southeast of New Orleans, Louisiana.

Vermillion 380. This property was acquired through Forest s acquisition of Forcenergy Inc in 2000. Forest subsequently sold a 50% working interest to Unocal in 2001. As part of the Unocal acquisition in 2003, Forest repurchased Unocal s 50% working interest. As of March 2, 2006, Mariner operates the property and owns working interests in the individual wells ranging from approximately 55% to 100%. The property is located in approximately 320 feet of water, approximately 135 miles southeast of Cameron, Louisiana.

West Cameron 110. A 37.5% working interest in this property was acquired through Forest s acquisition of Forcenergy Inc in 2000. BP operates the property. The property is located in approximately 320 feet of water, approximately 21 miles south of Cameron, Louisiana.

West Cameron 111/112. This property was acquired through Forest s acquisition of Forcenergy Inc in 2000. Forest initially held a 100% working interest in the property and sold a portion of its working interest in 2003 and, as a result, Mariner owns a 55% working interest. As of March 2, 2006, Mariner operates the property. The property is located in approximately 40 feet of water, approximately 45 miles southeast of Cameron, Louisiana.

West Cameron 205. This property was acquired through Forest s acquisition of Forcenergy Inc in 2000. As of March 2, 2006, Mariner operates the property and owns a 100% working interest in the property, which is located in approximately 50 feet of water, approximately 36 miles south of Cameron, Louisiana.

Other Projects and Activity. In connection with the March 2005 Central Gulf of Mexico federal lease sale, Mariner was awarded West Cameron block 386 located in water depth of approximately 85 feet. In connection with the August 2005 Western Gulf of Mexico lease sale, we were awarded one shelf block (High Island A2) and four deepwater blocks (East Breaks 344, East Breaks 843, East Breaks 844 and East Breaks 709).

In May 2005, Mariner drilled the Capricorn discovery well, which encountered over 100 net feet of pay in four zones. The Capricorn project is located in High Island block A341 approximately 115 miles south southwest of Cameron, Louisiana in approximately 240 feet of water. We anticipate drilling an appraisal well and installing the necessary platform and facilities in the second quarter of 2006, with first production anticipated in 2006. We are the operator and own a 60% working interest in the project.

In late 2002, Mariner drilled a successful exploration well on our Mississippi Canyon 66 (Ochre) prospect and commenced production in the first quarter of 2004 via subsea tieback of approximately 7 miles to the Taylor Mississippi Canyon 20 platform. In September 2004, Hurricane Ivan destroyed the Taylor platform. We have entered into a production handling agreement with the operator of a nearby replacement host facility, and production is expected to recommence in the second quarter of 2006, following completion of repairs to the host facility necessitated by damage inflicted by Hurricane Katrina.

In connection with the March 2006 Central Gulf of Mexico lease sale, Mariner was the high bidder on ten blocks, including two deepwater blocks, at a potential aggregate cost of $18 million to Mariner.

Table of Contents

Estimated Proved Reserves

The following table sets forth certain information with respect to our estimated proved reserves by geographic area as of December 31, 2005. Reserve volumes and values were determined under the method prescribed by the SEC which requires the application of period-end prices and costs held constant throughout the projected reserve life. The reserve information as of December 31, 2005 for Mariner is based on estimates made in a reserve report prepared by Ryder Scott.

	Estimated Proved Reserve Quantities						
Geographic Area	Oil (MMbbls)	Natural Gas (Bcf)	Total (Bcfe)	PV10 Value(3) Developed	Undeveloped ($ Millions)	Total	Standardized Measure ($ Millions)
West Texas Permian Basin	16.7	105.5	205.5	$ 333.7	$ 173.4	$ 507.1	
Gulf of Mexico Deepwater(1)	4.7	83.2	111.1	383.3	257.4	640.7	
Gulf of Mexico Shelf(2)	0.3	19.0	21.0	132.6	1.4	134.0	
Total	21.7	207.7	337.6	$ 849.6	$ 432.2	$ 1,281.8	$ 906.6
Proved Developed Reserves	9.6	110.0	167.4				

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

(2) Shelf refers to water depths less than 1,300 feet and includes an insignificant amount of Gulf Coast onshore properties.

(3) Please see below for a definition of PV10 and a reconciliation of PV10 to the standardized measure of discounted future net cash flows.

The following table sets forth certain information with respect to our pro forma estimated proved reserves by geographic area as of December 31, 2005. This information is presented on a pro forma basis, giving effect to our merger with Forest Energy Resources as though it had been consummated on December 31, 2005. We consummated the merger on March 2, 2006. The reserve information as of December 31, 2005 for the Forest Gulf of Mexico operations is based on estimates made by internal staff engineers at Forest, which estimates were audited by Ryder Scott. Accordingly, the pro forma reserve information presented below includes both reserves that were estimated by Ryder Scott and reserves that were estimated by internal staff engineers at Forest and audited by Ryder Scott.

Pro Forma
Estimated Proved

Geographic Area	Reserve Quantities Oil (MMbbls)	Natural Gas (Bcf)	Total (Bcfe)	Developed	Pro Forma PV10 Value(3) Undeveloped ($ Millions)	Total	Pro Forma Standardized Measure ($ Millions)
West Texas Permian Basin	16.7	105.5	205.5	$ 333.7	$ 173.4	$ 507.1	
Gulf of Mexico Deepwater(1)	4.8	95.7	124.5	406.3	310.3	716.6	
Gulf of Mexico Shelf(2)	12.7	237.6	313.7	1,283.4	544.7	1,828.1	
Total	34.2	438.8	643.7	$ 2,023.4	$ 1,028.4	$ 3,051.8	$ 2,201.7
Proved Developed Reserves	18.4	252.1	362.3				

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

(2) Shelf refers to water depths less than 1,300 feet and includes an insignificant amount of Gulf Coast onshore properties.

Table of Contents

(3) Please see below for a definition of PV10 and a reconciliation of PV10 to the standardized measure of discounted future net cash flows.

Uncertainties are inherent in estimating quantities of proved reserves, including many 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.

PV10 is our estimated present value of future net revenues from proved reserves before income taxes. PV10 may be considered a non-GAAP financial measure under SEC regulations because it does not include the effects of future income taxes, as is required in computing the standardized measure of discounted future net cash flows. We believe PV10 to be an important measure for evaluating the relative significance of our natural gas and oil properties and that PV10 is widely used by professional analysts and investors in evaluating oil and gas companies. 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. We believe that most other companies in the oil and gas industry calculate PV10 on the same basis. Management also uses PV10 in evaluating acquisition candidates. PV10 is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting income taxes. The table below provides a reconciliation of PV10 (and, with respect to 2005, pro forma PV10) to the standardized measure of discounted future net cash flows.

	Pro Forma At December 31, 2005	At December 31, 2005	2004	2003
PV10	$ 3,051.8	$ 1,281.8	$ 668.0	$ 533.5
Future income taxes, discounted at 10%	850.1	375.2	173.6	115.3
Standardized measure of discounted future net cash flows	$ 2,201.7	$ 906.6	$ 494.4	$ 418.2

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Therefore, without reserve additions in excess of production through successful exploration and development activities or acquisitions, Mariner s reserves and production will decline. See Item 1A and Note 11 to the Mariner financial statements included elsewhere in this Annual Report for a discussion of the risks inherent in oil and natural gas estimates and for certain additional information concerning the proved reserves.

The weighted average prices of oil and natural gas at December 31, 2005 used in the proved reserve and future net revenues estimates above were calculated using NYMEX prices at December 31, 2005, of $61.04 per bbl of oil and $10.05 per MMBtu of gas, adjusted for our price differentials but excluding the effects of hedging.

Table of Contents

Production

The following table presents certain information with respect to net oil and natural gas production attributable to our properties, average sales price received and expenses per unit of production during the periods indicated. The 2005 information is also presented on a pro forma basis, giving effect to our merger with Forest Energy Resources as though it had been consummated on January 1, 2005. We consummated the merger on March 2, 2006.

	Pro Forma Year Ended December 31, 2005	Year Ended December 31, 2005	2004	2003
Production:				
Natural Gas (Bcf)	67.5	18.4	23.8	23.8
Oil (MMbbls)	4.6	1.8	2.3	1.6
Total natural gas equivalent (Bcfe)	94.9	29.1	37.6	33.4
Average realized sales price per unit (excluding effects of hedging):				
Natural gas ($/Mcf)	$ 8.04	$ 8.33	$ 6.12	$ 5.43
Oil ($/bbl)	46.86	51.66	38.52	26.85
Total natural gas equivalent ($/Mcfe)	8.07	8.43	6.23	5.15
Average realized sales price per unit (including effects of hedging):				
Natural gas ($/Mcf)	$ 6.40	$ 6.66	$ 5.80	$ 4.40
Oil ($/bbl)	34.18	41.23	33.17	23.74
Total natural gas equivalent ($/Mcfe)	6.20	6.74	5.70	4.27
Expenses ($/Mcfe):				
Lease operating expenses	$ 1.17	$ 1.03	$ 0.68	$ 0.74
Transportation	0.06	0.08	0.08	0.19
General and administrative, net (1)		1.27	0.23	0.24
Depreciation, depletion and amortization (excluding impairments) (2)	3.47	2.04	1.73	1.45

(1) Net of overhead reimbursements received from other working interest owners and amounts capitalized under the full cost accounting method. Includes non-cash stock compensation expense of $25.7 million in 2005. General and administrative expenses, net, are not included in pro forma 2005 because accounts of such costs were not historically maintained for the Forest Gulf of Mexico operations as a separate business unit. We believe the overhead costs associated with the Forest Gulf of Mexico operations in 2006 will approximate $6.4 million, net of capitalized amounts.

(2) Pro forma depreciation, depletion and amortization gives effect to the acquisition of the Forest Gulf of Mexico operations and a preliminary estimate of their step-up in basis using the unit of production method under the full cost method of accounting.

Table of Contents

Productive Wells

The following table sets forth the number of productive oil and gas wells in which we owned a working interest at December 31, 2005 and December 31, 2004 and on a pro forma basis at December 31, 2005.

	Pro Forma at December 31, 2005		Total Productive Wells at December 31, 2005		December 31, 2004	
	Gross	Net	Gross	Net	Gross	Net
Oil	669	335.0	492	271.3	197	127.9
Gas	266	117.3	37	10.7	34	9.5
Total	935	452.3	529	282.0	231	137.4

Acreage

The following table sets forth certain information with respect to actual and pro forma developed and undeveloped acreage as of December 31, 2005. The pro forma information gives effect to our merger with Forest Energy Resources as though it had been consummated on December 31, 2005. We consummated the merger on March 2, 2006.

	Pro Forma At December 31, 2005				At December 31, 2005			
	Developed Acres(1)		Undeveloped Acres(2)		Developed Acres(1)		Undeveloped Acres(2)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
West Texas	59,974	31,199			59,974	31,199		
Gulf of Mexico Deepwater(3)	90,720	36,035	332,528	205,285	79,200	30,275	259,200	154,996
Gulf of Mexico Shelf(4)	1,007,882	399,184	399,792	251,915	136,062	40,435	137,128	82,758
Other Onshore	3,392	744	856	243	3,392	744	856	243
Total	1,161,968	467,162	733,176	457,443	278,628	102,653	397,184	237,997

(1) Developed acres are acres spaced or assigned to productive wells.

(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

(3) Deepwater refers to water depths greater than 1,300 feet (the approximate depth of deepwater designated for royalty purposes by the U.S. Minerals Management Service).

(4) Shelf refers to water depths less than 1,300 feet.

The following table sets forth Mariner s offshore undeveloped acreage as of December 31, 2005 that is subject to expiration during the three years ended December 31, 2008. The amount of onshore undeveloped acreage subject to expiration is not material.

	Undeveloped Acreage Subject to Expiration in the Year Ended December 31,					
	2006		2007		2008	
	Gross	Net	Gross	Net	Gross	Net
Gulf of Mexico Deepwater	46,080	12,988	28,800	9,360	51,840	30,240
Gulf of Mexico Shelf	10,760	6,260	46,000	31,183	25,760	16,510
Total	56,840	19,248	74,800	40,543	77,600	46,750

Drilling Activity

Certain information with regard to our drilling activity during the years ended December 31, 2005, 2004 and 2003 is set forth below.

	Year Ended December 31,					
	2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Producing	3	1.13	7	3.34	6	2.03
Dry	7	2.44	7	2.65	6	2.35
Total	10	3.57	14	5.99	12	4.38
Development wells:						
Producing	93	54.20	56	34.84	45	30.07
Dry			1	0.68		
Total	93	54.20	57	35.52	45	30.07
Total wells:						
Producing	96	55.33	63	38.18	51	32.10
Dry	7	2.44	8	3.33	6	2.35
Total	103	57.77	71	41.51	57	34.45

We were in the process of drilling nine gross (4.46 net) wells as of December 31, 2005.

Property Dispositions

When appropriate, we consider the sale of discoveries that are not yet producing or have recently begun producing when we believe we can obtain acceptable returns on our investment without holding the investment through depletion. Such sales enable us to maintain and redeploy the proceeds to activities that we believe have a higher potential financial return. No property dispositions of producing properties were made during the three years ended December 31, 2005. However, we sold working interests totaling 50% in each of our non-producing deepwater Falcon and Harrier projects in two separate sales for $48.8 million in 2002 and $121.6 million in 2003.

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 purchasers under short-term (less than 12 months) contracts at

Table of Contents

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, 2005	2004	2003
Sempra		*	34%
Bridgeline Gas Distributing Company	15%	27%	19%
Trammo Petroleum Inc.	*	9%	14%
Duke Energy	*	*	6%
Genesis Crude Oil LP		*	4%
Chevron Texaco and affiliates	24%	18%	
BP Energy	*	12%	
Plains Marketing LP	10%		

* Less than 1%

Title to Properties

Substantially all of our properties currently are subject to liens securing our 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 interferes 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 generally are not as likely to arise with respect to offshore oil and gas properties as with respect to onshore properties.

Competition

We believe that our leasehold acreage, exploration, drilling and production capabilities, large 3-D seismic database and technical and operational experience generally enable us to compete effectively. However, our competitors include major integrated oil and natural gas companies and numerous independent oil and natural gas companies, individuals and drilling and income programs. 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.

Table of Contents

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 Minerals Management Service, or 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 each post-2000 lease sale that has occurred to date, the MMS has specified the water depth categories and royalty suspension volumes applicable to production from leases issued in the sale.

In 2004, the MMS adopted additional royalty relief incentives for production of natural gas from reservoirs located deep under shallow waters of the Gulf of Mexico. These incentives apply to gas produced in water depths of less than 200 meters and from deep gas accumulations located at depths of greater than 15,000 feet below the shelf. 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 normal royalty due for leases in water depths of 400 meters or less is 16.7% of production, and the 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 leases from the MMS 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 we have been required to pay royalties for natural gas produced in those years. However, we have contested the MMS authority 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 Item 3 of this Annual Report.

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 and Forest, 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 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 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. The Oil Pollution Act of 1990, or 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 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. 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.

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 operator of a hazardous waste treatment, stora or disposal facility. RCRA specifically excludes from the definition of hazardous waste drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil and natural gas. A similar exemption is contained in many of the state counterparts to RCRA. As a result, we are not required to comply with a substantial portion of RCRA s requirements because our operations generate minimal quantities of hazardous wastes. However, these wastes may be regulated by EPA or state agencies as solid waste. In addition, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes, and waste compressor oils, may be regulated under RCRA as hazardous waste. We do not believe the current costs of managing our wastes, as they are presently classified, to be significant. However, any repeal or modification of the oil and natural gas exploration and production exemption, or modifications of similar exemptions in analogous state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us, as well as our competitors, to incur increased operating expenses.

Employees

As of March 2, 2006, we had 196 full-time employees. Our employees are not represented by any labor unions. We consider relations with our employees to be satisfactory. We have never experienced a work stoppage or strike.

Insurance Matters

In September 2004, we incurred damage from Hurricane Ivan that affected our Mississippi Canyon 66 (Ochre) and Mississippi Canyon 357 fields. Production from Mississippi Canyon 357 was shut-in until March 2005, when necessary repairs were completed and production recommenced. Production from Ochre is currently shut-in awaiting rerouting of umbilical and flow lines to another host platform. Prior to Hurricane Ivan, this field was producing at a net rate of approximately 6.5 MMcfe per day. Production from Ochre is expected to recommence in the second quarter of 2006. In addition, a semi-submersible rig on location at Mariner s Viosca Knoll 917 (Swordfish) field was blown off location by the hurricane and incurred damage. Until we are able to complete all the repair work and submit costs to the insurance underwriters for review, the full extent of our insurance recovery and the resulting net cost to Mariner is unknown. For the insurance period ending September 30, 2004, we carried an annual deductible of $1.25 million and a single occurrence deductible of $.375 million.

In 2005 our operations were adversely affected by one of the most active and severe hurricane seasons in recorded history. As of December 31, 2005 we had approximately 5 MMcfe per day of net production shut-in as a result of

Hurricanes Katrina and Rita, and approximately 56 MMcfe per day on a pro forma basis. We estimate that as of March 15, 2006 approximately 42 MMcfe per day remains shut in. Additionally, we experienced delays in the startup of four of our deepwater projects primarily as a result of Hurricane Katrina. Two of the projects have commenced production, and two are anticipated to commence production in the second quarter of 2006. For the period September through December 2005, we estimate that approximately 6-8 Bcfe of production (approximately 15-20 Bcfe on a pro forma basis) was deferred because of the hurricanes. We also estimate that an additional 8 Bcfe of pro forma production will be deferred in 2006 before repairs to offshore and onshore infrastructure are fully completed, allowing return of full production from our fields. However, the actual volumes deferred in 2006 will vary based on circumstances beyond our control, including the timing of repairs to both onshore and offshore platforms, pipelines and facilities, the actions of operators on our fields, availability of service equipment, and weather.

We estimate the costs to repair damage caused by the hurricanes to our platforms and facilities will total approximately $50 million. However, until we are able to complete all the repair work this estimate is subject to significant variance. For the insurance period covering the 2005 hurricane activity, we carried a $3 million annual deductible and a $0.5 million single occurrence deductible for the Mariner assets. Insurance covering the Forest Gulf of Mexico properties carried a $5 million deductible for each occurrence. Until the repairs are completed and we submit costs to our insurance underwriters for review, the full extent of our insurance recoveries and the resulting net cost to us for Hurricanes Katrina and Rita will be unknown. However, we expect the total costs not covered by the combined insurance policies to be less than $15 million.

Effective March 2, 2006, Mariner has been accepted as a member of OIL Insurance, Ltd., an industry insurance cooperative, through which the assets of both Mariner and the Forest Gulf of Mexico operations are insured. The coverage contains a $5 million annual per-occurrence deductible for the combined assets and a $250 million per-occurrence loss limit. However, if a single event causes losses to OIL insured assets in excess of $1 billion in the aggregate (effective June 1, 2006, such amount will be reduced to $500 million), amounts covered for such losses will be reduced on a pro rata basis among OIL members. Pending review of our insurance program, we have maintained our commercially underwritten insurance coverage for the pre-merger Mariner assets, which coverage expires on September 30, 2006. This coverage contains a $3 million annual deductible and a $500,000 occurrence deductible, $150 million of aggregate loss limits, and limited business interruption coverage. While the coverage remains in effect, it will be primary to the OIL coverage for the pre-merger Mariner assets.

Enron Related Matters

In 1996, JEDI, an indirect wholly owned subsidiary of Enron Corp., acquired approximately 96% of Mariner Energy LLC, which at the time of acquisition indirectly owned 100% of Mariner Energy, Inc. After JEDI acquired us, we continued our prior business as an independent oil and natural gas exploration, development and production company. In 2001, Enron Corp. and certain of its subsidiaries (excluding JEDI) became debtors in Chapter 11 bankruptcy proceedings. Mariner Energy, Inc. was not one of the debtors in those proceedings. While the bankruptcy proceedings were ongoing, we continued to operate our business as an indirect subsidiary of JEDI. We remained an indirect subsidiary of JEDI until March of 2004 when our former indirect parent company, Mariner Energy LLC, merged with an affiliate of the private equity funds Carlyle/Riverstone Global Energy and Power Fund II, L.P. and ACON Investments 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, since March 2004, JEDI no longer owns any direct or indirect interest in Mariner, and we are no longer affiliated with JEDI or Enron Corp. Also in connection with the merger, warrants to purchase common stock of Mariner Energy LLC that were held by another Enron Corp. affiliate were exercised and the holders received their pro rata portion of the merger consideration, and a term loan owed by Mariner Energy LLC to the same Enron Corp. affiliate was repaid in full.

Prior to the merger, we filed two proofs of claim in the Enron Corp. bankruptcy proceedings. These claims, aggregating $10.7 million, were for unpaid amounts owed to us by Enron Corp. subsidiaries under the terms of various physical commodity contracts and hedging contracts entered into prior to the Enron Corp. bankruptcy filing. We assigned these claims to JEDI as part of the merger consideration payable to JEDI under the terms of the merger agreement. Thus, as of this date, we have no claims pending in the Enron Corp. bankruptcy proceedings.

Table of Contents

As part of the merger consideration payable to JEDI, we also issued a term promissory note to JEDI in the amount of $10 million. The note bore interest, paid in kind, 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 at 10% per annum. The JEDI promissory note was secured by a lien on three of our properties located in the Outer Continental Shelf of the Gulf of Mexico. We used a portion of proceeds from the common stock we sold in our March 2005 private equity placement to repay $6 million of the JEDI Note. The note matured on March 2, 2006 and was repaid in full.

Under the merger agreement, JEDI and the other former stockholders of our parent company were entitled to receive on or before February 28, 2005, additional contingent merger consideration based upon the results of a five-well drilling program. In September 2004, we prepaid, with a 10% prepayment discount, approximately $161,000 as the additional contingent merger consideration due with respect to the program.

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 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/divisions/corpfin/forms/regsx.htm#gas.*

3-D seismic. (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 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.

Table of Contents

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.

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, as the case may be.

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

Table of Contents

construed as being the fair market value of the properties. Estimates of future net revenues are made using oil and natural gas prices and operating costs at the date indicated and held constant for the life of the reserves.

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

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

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

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

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

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/divisions/corpfin/forms/regsx.htm#gas.*

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 definition of this term can be viewed on the website at *http://www.sec.gov/divisions/corpfin/forms/regsx.htm#gas.*

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.

Table of Contents

Item 1A. ***Risk Factors.***

Risks Relating to the Oil and Natural Gas Industry and 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 62% of our estimated proved reserves (68% on a pro forma basis) as of December 31, 2005 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, 2005, 50% of our estimated proved reserves were proved undeveloped (44% on a pro forma basis).

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 Annual Report. See Estimated Proved Reserves under Items 1 and 2 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 these assumptions or discount factor are materially inaccurate, our revenues, profitability and cash flow could be materially less than our estimates.

The present value of future net revenues from our proved reserves referred to in this Annual 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 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 merger with Forest Energy Resources. 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 lower percentages of their reserves over a similar time period, such as

Table of Contents

those producers who have a portion of their reserves outside of the Gulf of Mexico 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 65% of our total estimated proved reserves are developed non-producing or undeveloped (71% on a pro forma basis), and those reserves may not ultimately be produced or developed.

As of December 31, 2005, approximately 15% of our total estimated proved reserves were developed non-producing (27% on a pro forma basis) and approximately 50% were undeveloped (44% on a pro forma basis). These reserves may not ultimately be developed or produced. Furthermore, not all of our undeveloped or developed non-producing reserves may be ultimately produced at the time periods we have planned, at the costs we have budgeted, or at all. As a result, we may not find commercially viable quantities of oil and natural gas, 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

Table of Contents

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

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

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

- fires;
- explosions;
- blow-outs and surface cratering;
- uncontrollable flows of underground natural gas, oil and formation water;
- natural disasters, such as 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. For more information on the impact of recent hurricanes on our operations, see Recent Developments under Item 7.

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

Table of Contents

these operations. Because of the lack and high cost of infrastructure, some reserve discoveries in the deepwater may never be produced economically.

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

We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in oil and natural gas prices and to achieve more predictable cash flow. These financial arrangements typically take the form of price swap contracts and costless collars. Hedging arrangements expose us to the risk of financial loss in some circumstances, including situations when the other party to the hedging contract defaults on its contract or production is less than expected. During periods of high commodity prices, hedging arrangements may limit significantly the extent to which we can realize financial gains from such higher prices. For example, in calendar year 2005, our hedging arrangements reduced the benefit we received from increases in the prices for oil and natural gas by approximately $49 million. Although we currently maintain an active hedging program, we may choose not to engage in hedging transactions in the future. As a result, we may be affected adversely during periods of declining oil and natural gas prices.

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

We depend on our ability to obtain financing beyond our cash flow from operations. Historically, we have financed our business plan and operations primarily with internally generated cash flow, bank borrowings, proceeds from the sale of oil and natural gas properties, 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 be required to meet our needs from our excess cash flow, debt financings and additional equity offerings (subject to certain federal tax limitations during the two-year period following the spin-off). Sufficient capital may not be available on acceptable terms or at all. If we cannot obtain additional capital resources, we may curtail our drilling, development and other activities or be forced to sell some of our assets on unfavorable terms.

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

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

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

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 certain 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.

Table of Contents

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.

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 Regulation under Items 1 and 2 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 resulting net cost to us for the hurricanes. See Insurance Matters under Items 1 and 2 for more information.

Risks Relating to Our Merger with Forest Energy Resources

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

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

- the challenge of integrating the Forest Gulf of Mexico operations while carrying on the ongoing operations of our business;
- the challenge of managing a significantly larger company, with more than twice the PV10 of Mariner prior to the merger;
- 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 merger; 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 merger, our results of operations may be lower than we expect.

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

Table of Contents

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

We anticipate that from time to time we will incur charges to our earnings in connection with the integration of the Forest Gulf of Mexico operations into our business. These charges will include expenses incurred in connection with relocating and retaining employees and increased professional and consulting costs. We also expect to incur significant expenses related to being a public company. We are not yet able to quantify the costs or timing of the integration. Some factors affecting the cost of the integration include the training of new employees, the amount of severance and other employee-related payments resulting from the merger, and the limited length of time during which transitional services are provided by Forest.

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 (such as the issuance of our common shares or the undertaking of a change in control) that otherwise could be advantageous.

In connection with the merger 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, such as the redemption of our common stock, the issuance of equity securities and the utilization of our stock as currency in an acquisition, will be limited for a period of two years following the spin-off.

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

Item 1B. *Unresolved Staff Comments.*

None.

Item 3. *Legal Proceedings.*

Mariner operates numerous properties in the Gulf of Mexico. Two of these properties were leased from the MMS subject to the RRA. The RRA relieved the obligation to pay royalties on certain predetermined leases until a designated volume is produced. These two leases contained language that limited royalty relief if commodity prices exceeded predetermined levels. In 2000, 2001, 2003, 2004 and 2005 commodity prices exceeded the predetermined levels. Management believes the MMS did not have the authority to set pricing limits and we filed an administrative appeal contesting the MMS order and have withheld royalties regarding this matter. The MMS filed a motion to dismiss our appeal with the Board of Land Appeals of the Department of the Interior. On April 6, 2005, the Board of Land Appeals granted MMS motion and dismissed our appeal. On October 3, 2005, we filed suit in the U.S. District Court for the Southern District of Texas seeking judicial review of the dismissal of our appeal by the Board of Land Appeals. Mariner has recorded a liability for 100% of the potential exposure on this matter, which on December 31, 2005 was $16.0 million.

In addition to the foregoing, by letter dated December 2, 2005, the MMS notified Mariner that 2004 commodity prices exceeded the predetermined levels and, accordingly, that royalties were due on natural gas and oil produced in calendar year 2004 from federal offshore leases with confirmed royalty suspension volumes as defined by the RRA. On December 29, 2005, Mariner filed a notice of intent to appeal this royalty demand from the MMS. Mariner has paid royalties on calendar year 2004 production from federal offshore leases in which it owns an interest except for 2004 production from Ewing Bank 966 and Garden Banks 367, which are the two leases at issue in the lawsuit discussed above.

Table of Contents

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, in which the exposure, individually and in the aggregate, is not considered material by and to us.

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

Not applicable.

PART II

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

The shares of Mariner common stock are listed and traded on the New York Stock Exchange (NYSE), under the symbol ME . Our common stock began trading regular way on March 3, 2006, following the consummation of our merger with Forest Energy Resources.

The high and low sales prices of our common stock on the NYSE during the period from March 3, 2006 through March 24, 2006 were $20.27 and $18.30, respectively.

As of March 17, 2006 there were 519 holders of record of the Company 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 2003, 2004 or 2005. See Item 7, Liquidity and Capital Resources Credit Facility and Item 8, Note 4 to Mariner s Financial Statements for a discussion of certain covenants in our credit facility which restrict our ability to pay dividends.

See Item 11 for information relating to our equity compensation plans.

Recent Sales and Issuances of Unregistered Securities

In 2005 we sold and issued the following unregistered securities:

On March 11, 2005, we issued 16,350,000 shares of our common stock in consideration of $212,877,000 before expenses to qualified institutional buyers, non-U.S. persons and accredited investors in transactions exempt from registration under Section 4(2) of the Securities Act. We paid Friedman, Billings, Ramsey & Co., Inc., who acted as placement agent in this transaction, $16,023,000 in discounts and placement fees. A selling stockholder in the offering paid an additional $10,035,200 in discounts and placement fees to Friedman, Billings, Ramsey & Co., Inc.

On March 11, 2005, we issued 2,267,270 shares of restricted common stock to employees pursuant to our Equity Participation Plan. The issuance of these shares was exempt from the registration requirements of the Securities Act pursuant to Rule 701. See Item 11, Equity Participation Plan.

During 2005, we issued options exercisable for an aggregate 809,000 shares of common stock to employees and directors pursuant to our Stock Incentive Plan as follows: options for an aggregate of 798,960 shares at $14.00 per share were issued on March 11, May 16, July 18 and July 25, 2005; options for an aggregate of 9,000 shares at $15.50 per share were issued on August 11, 2005; and an option for 1,040 shares at $17.00 per share was issued on September 19, 2005. The issuance of those options was exempt from the registration requirements of the Securities Act pursuant to Rule 701. These options generally vest and become exercisable in one-third increments on the first three anniversaries of the grant date (or, in the case of directors, on the first three annual stockholder meeting dates following grant), subject to acceleration in certain instances, including for employee options when the deemed change of control occurred upon the merger with Forest Energy Resources on March 2, 2006, whereupon options for an aggregate of 216,000 shares held by non-executive employees fully vested. Mariner s executive officers waived accelerated vesting of their options for an aggregate of

Table of Contents

584,000 shares. See Item 11, Executive Compensation Employment Agreements and Other Arrangements and Amended and Restated Stock Incentive Plan.

The registration statement on Form S-1 (SEC File No. 333-124858), as amended, filed by Mariner was declared effective by the SEC on February 10, 2006. Mariner registered for sale 33,348,130 shares of common stock, all of which were held by selling stockholders named in the registration statement. Under the registration statement, the shares can be offered and sold by the selling stockholders in one or more transactions at fixed prices, prevailing market prices or negotiated prices. There was no underwriter for the offering. Mariner did not sell any shares for our own account, and did not and will not receive any proceeds from the sale of securities by any selling stockholders. Mariner incurred expenses as detailed in the registration statement of approximately $1.9 million, none of which were direct or indirect payments to directors, officers or general partners of Mariner or their associates, or to persons owning 10% or more of any class of equity securities of Mariner.

Item 6. *Selected Financial Data.*

The following table shows Mariner s historical consolidated financial data as of and for the year ended December 31, 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 three years ended December 31, 2003. The historical consolidated financial data as of and for the year ended December 31, 2005, the period from January 1, 2004 through March 2, 2004, the period from March 3, 2004 through December 31, 2004 and the year ended December 31, 2003, are derived from Mariner s audited financial statements included herein, and the historical consolidated financial data as of and for the two years ended December 31, 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, 2004, Mariner s former indirect parent, Mariner Energy LLC, merged with MEI Acquisitions, LLC, an affiliate of the private equity funds, Carlyle/Riverstone Global Energy and Power Fund II, L.P. and ACON Investments LLC. The financial information contained herein is presented in the style of Post-2004 Merger activity (for the March 3, 2004 through December 31, 2004 period and the year ended 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.

Table of Contents

	Post-2004 Merger		Pre-2004 Merger			
	Year Ended December 31, 2005	Period from March 3, 2004 through December 31, 2004	Period from January 1, 2004 through March 2, 2004	Year Ended December 31, 2003	2002	2001
	(in millions, except per share data)					
Statement of Operations Data:						
Total revenues(1)	$ 199.7	$ 174.4	$ 39.8	$ 142.5	$ 158.2	$ 155.0
Lease operating expenses	29.9	21.4	4.1	24.7	26.1	20.1
Transportation expenses	2.3	1.9	1.1	6.3	10.5	12.0
Depreciation, depletion and amortization	59.4	54.3	10.6	48.3	70.8	63.5
Impairment of production equipment held for use	1.8	1.0				
Derivative settlement				3.2		
Impairment of Enron related receivables					3.2	29.5
General and administrative expenses	37.1	7.6	1.1	8.1	7.7	9.3
Operating income	69.2	88.2	22.9	51.9	39.9	20.6
Interest income	0.8	0.2	0.1	0.8	0.4	0.7
Interest expense	(8.2)	(6.0)		(7.0)	(10.3)	(8.9)
Income before income taxes	61.8	82.4	23.0	45.7	30.0	12.4
Provision for income taxes	(21.3)	(28.8)	(8.1)	(9.4)		
Income before cumulative effect of change in accounting method net of tax effects	40.5	53.6	14.9	36.3	30.0	12.4
Income before cumulative effect per common share						
Basic	1.24	1.80	.50	1.22	1.01	.42
Diluted	1.20	1.80	.50	1.22	1.01	.42
Cumulative effect of changes in accounting method				1.9		
Net income	$ 40.5	$ 53.6	$ 14.9	$ 38.2	$ 30.0	$ 12.4
Net income per common share						
Basic	$ 1.24	$ 1.80	$ 0.50	$ 1.29	$ 1.01	$ 0.42
Diluted	1.20	1.80	0.50	1.29	1.01	0.42
Capital Expenditure and Disposal Data:						
Exploration, including leasehold/seismic	$ 60.9	$ 40.4	$ 7.5	$ 31.6	$ 40.4	$ 66.3
Development and other	191.8	93.2	7.8	51.7	65.7	98.2

Proceeds from property conveyances				(121.6)	(52.3)	(90.5)
Total capital expenditures net of proceeds from property conveyances	$ 252.7	$ 133.6	$ 15.3	$ (38.3)	$ 53.8	$ 74.0

(1) Includes effects of hedging.

	Post-2004 Merger		Pre-2004 Merger		
	December 31, 2005	December 31, 2004	2003	December 31, 2002	2001
		(in millions)			
Balance Sheet Data:(1)					
Property and equipment, net, full cost method	$ 515.9	$ 303.8	$ 207.9	$ 287.6	$ 290.6
Total assets	665.5	376.0	312.1	360.2	363.9
Long-term debt, less current maturities	156.0	115.0		99.8	99.8
Stockholders equity	213.3	133.9	218.2	170.1	180.1
Working capital (deficit)(2)	(46.4)	(18.7)	38.3	(24.4)	(19.6)

41

(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, deferred tax assets and restricted cash.

	Post-2004 Merger		Pre-2004 Merger			
	Year Ended December 31, 2005	Period from March 3, 2004 through December 31, 2004	Period from January 1, 2004 through March 2, 2004	Year Ended December 31, 2003	2002	2001
	(in millions)					
Other Financial Data:						
EBITDA(1)	$ 130.4	$ 143.5	$ 33.4	$ 100.3	$ 113.9	$ 113.6
Net cash provided by operating activities	165.4	135.2	20.3	88.9	60.3	113.5
Net cash (used) provided by investing activities	(247.8)	(133.0)	(15.3)	52.9	(53.8)	(74.0)
Net cash (used) provided by financing activities	84.4	64.9		(100.0)		(30.0)
Reconciliation of Non-GAAP Measures:						
EBITDA(1)	$ 130.4	$ 143.5	$ 33.4	$ 100.3	$ 113.9	$ 113.6
Changes in working capital	20.0	6.2	(13.2)	7.2	(20.4)	7.5
Non-cash hedge gain(2)	(4.5)	(7.9)		(2.0)	(23.2)	
Amortization/other	1.2	0.8			(0.1)	0.6
Stock compensation expense	25.7					
Net interest expense	(7.4)	(5.8)	0.1	(6.2)	(9.9)	(8.2)
Income tax expense		(1.6)		(10.4)		
Net cash provided by operating activities	$ 165.4	$ 135.2	$ 20.3	$ 88.9	$ 60.3	$ 113.5

(1) EBITDA means earnings before interest, income taxes, depreciation, depletion and amortization and impairments. For the year ended December 31, 2005, EBITDA includes $25.7 million in non-cash stock compensation expense related to restricted stock and stock options granted in 2005. We believe that EBITDA is a widely accepted financial indicator that provides additional information about our ability to meet our future requirements for debt service, capital expenditures and working capital, but EBITDA should not be considered in isolation or as a substitute for net income, operating income, net cash provided by operating activities or any other measure of financial performance presented in accordance with generally accepted accounting principles or as a measure of a company s profitability or liquidity.

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

Table of Contents

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 the Gulf of Mexico and the Permian Basin in West Texas. In the Gulf of Mexico, our areas of operation include the deepwater and the shelf area. We have been active in the Gulf of Mexico and West Texas since the mid-1980s. As a result of increased drilling of shelf prospects, the acquisition of Forest s offshore Gulf of Mexico assets located primarily on the shelf, and development activities in the West Texas Permian Basin, we have evolved from a company with primarily a deepwater focus to one with a balance of exploitation and exploration of the Gulf of Mexico deepwater and shelf, and longer-lived West Texas Permian Basin properties.

On March 2, 2004, Mariner s former indirect parent, Mariner Energy LLC, merged with MEI Acquisitions, LLC, an affiliate of the private equity funds, Carlyle/Riverstone Global Energy and Power Fund II, L.P. and ACON Investments LLC. Prior to the merger, we were owned indirectly by JEDI, which was an indirect wholly-owned subsidiary of Enron Corp. The gross merger consideration was $271.1 million (which excludes $7.0 million of acquisition costs and other expenses paid directly by Mariner), $100 million of which was provided as equity by our new owners. As a result of the merger, we are no longer affiliated with Enron Corp. See Enron Related Matters under Item 1. 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 credit facility, and the balance to pay down $6 million of a $10 million promissory note payable to JEDI. See Enron Related Matters under Item 1. As a result, after the private placement, an affiliate of MEI Acquisitions Holdings, LLC beneficially owned approximately 5.3% of our outstanding common stock.

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

Table of Contents

Recent Developments

On March 2, 2006, we completed a merger transaction with Forest Energy Resources. Prior to the consummation of the merger, Forest transferred and contributed the assets and certain liabilities associated with its offshore Gulf of Mexico operations to Forest Energy Resources. Immediately prior to the 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, and become a new wholly owned subsidiary of Mariner. Upon the 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. Our acquisition of Forest Energy Resources added approximately 306.1 Bcfe of estimated proved reserves as of December 31, 2005, of which approximately 76% were natural gas and 24% were oil and condensate and natural gas liquids. As of December 31, 2005, the standardized measure of discounted future net cash flows attributable to Forest Energy Resources estimated proved reserves was approximately $1.3 billion. Please see Estimated Proved Reserves in Items 1 and 2 for a discussion of our calculation of the standardized measure of discounted future net cash flows.

In 2005 our operations were adversely affected by one of the most active and severe hurricane seasons in recorded history. As of December 31, 2005, we had approximately 5 MMcfe per day of net production shut-in as a result of Hurricanes Katrina and Rita, and approximately 56 MMcfe per day on a pro forma basis. We estimate that as of March 15, 2006 approximately 42 MMcfe per day remains shut in. Additionally, we experienced delays in startup of four of our deepwater projects primarily as a result of Hurricane Katrina. Two of the projects have commenced production, and two are anticipated to commence production in the second quarter of 2006. For the period September through December 2005, we estimate that approximately 6-8 Bcfe of production (approximately 15-20 Bcfe on a pro forma basis) was deferred because of the hurricanes. We also estimate that an additional 8 Bcfe of production will be deferred in 2006 before repairs to offshore and onshore infrastructure are fully completed, allowing return of full production from our fields. However, the actual volumes deferred in 2006 will vary based on circumstances beyond our control, including the timing of repairs to both onshore and offshore platforms, pipelines and facilities, the actions of operators on our fields, availability of service equipment, and weather.

We estimate the costs to repair damage caused by the hurricanes to our platforms and facilities will total approximately $50 million. However, until we are able to complete all the repair work this estimate is subject to significant variance. For the insurance period covering the 2005 hurricane activity, we carried a $3 million annual deductible and a $0.5 million single occurrence deductible for the Mariner assets. Insurance covering the Forest Gulf of Mexico properties carried a $5 million deductible for each occurrence. Until the repairs are completed and we submit costs to our insurance underwriters for review, the full extent of our insurance recoveries and the resulting net cost to us for Hurricanes Katrina and Rita will be unknown. However, we expect the total costs not covered by the combined insurance policies to be less than $15 million.

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

2005 Highlights

During the year ended December 31, 2005, we recognized net income of $40.5 million on total revenues of $199.7 million compared to net income of $68.4 million on total revenues of $214.2 million in 2004. Net income decreased 41% compared to 2004, primarily due to recognizing $25.7 million of stock compensation expense in 2005, and a 23% decrease in production, partially offset by a 35% improvement in net commodity prices realized by us (before the effects of hedging.) Our 2005 results were also negatively impacted by increased hedging losses of $49.3 million in 2005 compared to a $19.8 million loss in 2004. We produced approximately 29.1 Bcfe during 2005 and our average daily production rate was 80 MMcfe compared to

37.6 Bcfe, or 103 MMcfe per day, for 2004. Production during the last two quarters of 2005 was negatively impacted by the effects of the 2005 hurricane season. We invested approximately $252.7 million in total capital in 2005 compared to $148.9 million in 2004.

Our 2005 results reflect the private placement of an additional 3.6 million shares of stock in March 2005. The net proceeds of approximately $44 million generated by the private placement were used to repay existing debt. We also granted 2,267,270 shares of restricted stock and options to purchase 809,000 shares of stock in 2005 and recorded compensation expense of $25.7 million in 2005 related to the restricted stock and options.

2004 Highlights

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

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

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

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

Production

Our production for 2005 averaged approximately 50 MMcf of natural gas per day and approximately 4,900 barrels of oil per day, or a total of approximately 80 MMcfe per day. Natural gas production comprised approximately 63% of total production in 2005 and 2004.

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 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). Production on our Rigel project commenced in the first quarter of 2006. We expect production on the two remaining projects to recommence in the second quarter of 2006.

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

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

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

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

Oil and Gas Property Costs

In 2005, we incurred approximately $242.6 million in capital costs related to property acquisitions, exploration, and development activities and approximately $10.1 million for capital costs associated with the installation of our Aldwell unit gathering system and other minor corporate items. Of the total $252.7 million of capital expenditures incurred in 2005, approximately 51% related to development activities and capitalized overhead and interest, 24% for exploration activities, including the acquisition of leasehold and seismic, 21% for property acquisitions, and the balance was associated with the Aldwell Unit gathering system and minor corporate items. Of the $121.7 million incurred on development activities and capitalized overhead and interest, approximately 27% were for onshore operations, 69% for deep water operations, and 4% for shallow Gulf of Mexico operations. Expenditures for property acquisitions included $46.1 million for assets located in the West Texas Permian Basin and $7.9 million to acquire additional interests in offshore Gulf of Mexico projects.

During 2004, we incurred approximately $148.9 million in capital expenditures with 60% related to development activities, 32% related to exploration activities, including the acquisition of leasehold and seismic, and the remainder related to acquisitions and other items (primarily capitalized overhead and interest). We spent approximately $88.6 million in development capital expenditures in 2004 primarily on Aldwell Unit development and for Viosca Knoll 917 (Swordfish), Mississippi Canyon 718 (Pluto), and West Cameron 333 (Royal Flush) offshore projects. All capital expenditures for exploration activities relate to offshore projects, and approximately 30% of exploration capital expended during 2004 was for leasehold, seismic, and geological and geophysical costs. During 2004 we participated in fourteen exploration wells, with seven being successful. We incurred approximately $47.9 million of exploration capital expenditures in 2004.

Oil and Gas Reserves

We have maintained our reserve base through exploration and exploitation activities despite selling 44.4 Bcfe of our reserves in 2002. Historically, we have not acquired significant reserves through acquisition activities; however, in 2005, we acquired 93.9 Bcfe of estimated proved reserves primarily in the West Texas Permian Basin area. In March 2006, we acquired estimated proved reserves of 306.1 Bcfe as a result of the merger with Forest Energy Resources. As of December 31, 2005, Ryder Scott estimated our net proved reserves at approximately 337.6 Bcfe, with a PV10 of approximately $1.3 billion and a standardized measure of discounted future net cash flows attributable to our estimated proved reserves of approximately $906.6 million. Please see Estimated Proved Reserves under Item 1 for a definition of PV10 and a reconciliation of PV10 to the standardized measure of discounted future net cash flows and for more information concerning our reserve estimates.

The development and acquisitions in the West Texas Permian Basin area and Gulf of Mexico deepwater divestitures have significantly changed our reserve profile since 2002. Proved reserves as of December 31, 2005 were comprised of 61% West Texas Permian Basin, 6% Gulf of Mexico shelf and 33% Gulf of Mexico deepwater compared to 33% West Texas Permian Basin, 19% Gulf of Mexico shelf and 48% Gulf of Mexico deepwater as of December 31, 2002. Proved undeveloped reserves were approximately 50% of total proved reserves as of December 31, 2005. Approximately 25% of proved undeveloped reserves were related to our West Texas Aldwell Unit, where we had 100% development drilling success on 170 wells from 2002 through 2005.

Since December 31, 1997, we have added proved undeveloped reserves attributable to 12 deepwater projects. As of December 31, 2005, ten of those projects have either been converted to proved developed reserves or sold as indicated in the following table.

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

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

(2)

This field was shut-in in April 2004 pending the drilling of a new well and installation of an extension to the existing infield flowline and umbilical. As a result, as of December 31, 2005, 8.9 Bcfe of our net proved reserves attributable to this project were classified as proved behind pipe reserves. We expect production from Pluto to recommence in the second quarter of 2006.

Table of Contents

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

Property	Net Proved Undeveloped Reserves (Bcfe)(1)	Year Added	Year Expected to Convert to Proved Developed Status
Green Canyon 646 (Daniel Boone)	16.4	2003	2008
Atwater Valley 380/381/382/425/426 (Bass Lite)	32.3	2005	2008

(1) Net proved undeveloped reserves attributable to the project as of December 31, 2005.

Oil and Natural Gas Prices and Hedging Activities

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

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

We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in oil and natural gas prices. Typically, our hedging strategy involves entering into commodity price swap arrangements and costless collars with third parties. Price swap arrangements establish a fixed price and an index-related price for the covered commodity. When the index-related price exceeds the fixed price, we pay the third party the difference, and when the fixed price exceeds the index-related prices, the third party pays us the difference. Costless collars establish fixed cap (maximum) and floor (minimum) prices as well as an index-related price for the covered commodity. When the index-related price exceeds the fixed cap price, we pay the third party the difference, and when the index-related price is less than the fixed floor price, the third party pays us the difference. While our hedging arrangements enable us to achieve a more predictable cash flow, these arrangements also limit the benefits of increased prices. As a result of increased oil and natural gas prices, we incurred cash hedging losses of $53.8 million in 2005, of which $4.5 million relates to the hedge liability recorded at the March 2, 2004 merger date. Major challenges related to our hedging activities include a determination of the proper production volumes to hedge and acceptable commodity price levels for each hedge transaction. Our hedging activities may also require that we post cash collateral with our counterparties from time to time to cover credit risk. We had no collateral requirements as of December 31, 2005 or December 31, 2004.

In accordance with purchase price accounting implemented at the time of the merger of our former indirect parent company on March 2, 2004, we recorded the mark-to-market liability of our hedge contracts at such date totaling $12.4 million as a liability on our balance sheet. As of December 31, 2005, the amount of our mark-to-market hedge liabilities totaled $63.8 million. See Liquidity and Capital Resources Commodity Prices and Related Hedging Activities.

For the year ended December 31, 2005, assuming a totally unhedged position, our price sensitivity for 2005 net revenues for a 10% change in average oil prices and average gas prices received is approximately $9.3 million and $15.3 million, respectively. For the year ended December 31, 2004, assuming a totally unhedged position, our price sensitivity for 2004 historical net revenues for a 10% change in average oil prices and average gas prices received is approximately $8.9 million and $14.5 million, respectively.

Operating Costs

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

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

Critical Accounting Policies and Estimates

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

Oil and Gas Properties

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

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

Proved Reserves

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

Table of Contents

Compensation Expense

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

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

Revenue Recognition

We use the entitlements method of accounting for the recognition of natural gas and oil revenues. Under this method of accounting, income is recorded based on our net revenue interest in production or nominated deliveries. We incur production gas volume imbalances in the ordinary course of business. Net deliveries in excess of entitled amounts are recorded as liabilities, while net under deliveries are reflected as assets. 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.

Income Taxes

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

Accrual for Future Abandonment Costs

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

Hedging Program

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

Table of Contents

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

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

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

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

Use of Estimates in the Preparation of Financial Statements

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

Results of Operations

For certain information with respect to our oil and natural gas production, average sales price received and expenses per unit of production for the three years ended December 31, 2005, see Production under Item 1.

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

	Non-GAAP Combined	Post-Merger Period from March 3, 2004 through	Pre-Merger Period from January 1, 2004 through

Summary Operating Information:	Year Ended December 31, 2005	December 31, 2004	December 31, 2004	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

Table of Contents

Summary Operating Information:	Non-GAAP Combined Year Ended December 31, 2005	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)			
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(1)	$ 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(1)	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 ($/Mcfe) realized(1)	6.74	5.70	5.65	5.92
Total natural gas equivalent ($/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	29,882	25,484	21,363	4,121
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 expenses	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

(1) 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, Pluto, and Rigel development projects was delayed awaiting repairs to host facilities. Swordfish recommenced production in the fourth quarter of 2005 and Rigel recommenced production in the first quarter of 2006. Ochre and Pluto are expected to commence production in the second 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 merger and $1.7 million generated by our West Texas Aldwell unit gathering system.

Lease operating expenses increased 17% to $29.9 million in 2005 from $25.5 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 $1.03 per Mcfe in 2005 compared to $0.68 per Mcfe in 2004. The increased per unit costs also reflect lower production rates in 2005, including hurricane-related disruptions.

Transportation expenses were $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.

Depreciation, depletion, and amortization (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.

General and administrative (G&A) expenses, which are 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 in 2005 compared to 2004.

Table of Contents

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.

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.

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

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

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

Natural gas (per Mcf) unhedged	5.43	6.12	6.13	6.05
Total natural gas equivalent ($/Mcfe) realized(1)	4.27	5.70	5.65	5.92
Total natural gas equivalent ($/Mcfe) unhedged	5.15	6.23	6.32	5.81

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

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

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

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

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

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

Transportation expenses were $3.0 million for 2004, compared to $6.3 million for 2003. In the fourth quarter of 2004, we filed new transportation allowances with the MMS for purpose of royalty calculation. This resulted in a $3.2 million decrease in transportation expense in 2004 compared to 2003. In addition, transportation expense from our new Roaring Fork field was offset by declines from our existing fields.

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

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

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

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

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

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

Liquidity and Capital Resources

Cash Flows and Liquidity

At December 31, 2005, we had $152 million in advances outstanding under our revolving credit facility with a borrowing base as of that date of $170 million. In January 2006, the borrowing base was increased to $185 million. In connection with the merger with Forest Energy Resources on March 2, 2006, we amended and restated our existing credit facility to increase maximum credit availability to $500 million, with a $400 million borrowing base as of that date. On March 2, 2006, after giving effect to funds required at closing to refinance $176.2 million of debt assumed in the merger and other merger-related costs, our total debt drawn under the facility was approximately $350 million, including a $4.2 million letter of credit required for plugging and abandonment obligations at one of our offshore fields. In addition, we have established a $40 million letter of credit for the benefit of Forest Oil Corporation to guarantee certain drilling obligations in West Texas that is not included as a use of our borrowing base availability. The $4 million balance remaining on a note payable to JEDI at December 31, 2005 was repaid in full on its maturity date of March 2, 2006.

Working capital at December 31, 2005 was negative $46.4 million, excluding current derivative liabilities and deferred taxes. Accrued liabilities (including accounts payable) and accrued receivables (including accounts receivable) at December 31, 2005 increased by approximately 91% and 68%, respectively, over levels at December 31, 2004 primarily due to increased accrued obligations for drilling and development projects in progress at year end 2005 and related accruals of amounts owed by partners. As of December 31, 2004, we had negative working capital of approximately $18.7 million compared to positive working capital of $38.3 million at December 31, 2003, in each case excluding current derivative liabilities and restricted cash. The reduction in working capital from 2003 is primarily the result of a change in the manner Mariner utilizes excess cash. At year end 2003, Mariner operated with no debt and consequently accumulated cash (approximately $60 million at year end 2003) generated by operations and asset sales in order to fund future obligations and business activities. In March 2004, Mariner entered into a revolving credit facility, and since then has utilized excess cash to pay down outstanding advances to maintain debt levels as low as possible. In addition, our accounts payable and accrued liabilities at December 31, 2004 increased by about 32% over levels at December 31, 2003 primarily as a result of funding for development of our deepwater projects in progress at year end.

Our 2005 capital expenditures were $252.7 million. Approximately 48% of our capital expenditures were incurred for development projects, 24% for exploration activities, 21% for acquisitions of developed properties, and the remainder for other items (primarily expenditures for our Aldwell gathering system, capitalized overhead and interest).

We anticipate that our capital expenditures for 2006 will approximate $463.5 million with approximately 57% allocated to development activities, 41% to exploration activities, and the remainder to other items (primarily capitalized overhead and interest). The 2006 budget is an increase of approximately 83% over our 2005 expenditures. The increase is primarily driven by the addition of the Forest Gulf of Mexico operations, continuation of our deepwater development activities, and expansion of our exploration activities, including increasing our acquisition of leasehold and seismic data. In addition, we expect to incur approximately $33 million for repairs of damage caused by Hurricanes Katrina and Rita in 2006. While this will be a cash outflow in 2006, we expect to recover these costs through insurance reimbursements later in 2006 or 2007. Since we believe these costs to be reimbursable, they will not be reflected in reported 2006 capital expenditures.

We believe our cash flows generated by operations will be sufficient to fund our anticipated capital expenditures. However, the effects of the 2005 hurricane season have reduced our anticipated cash flows coming into 2006 and some production continues to be deferred pending repairs to both offshore and onshore pipelines and facilities. We believe that by mid-year 2006 most of the production deferred by the 2005 hurricane season will be brought on-line. In addition, natural gas prices have weakened considerably in the first quarter of 2006 from 2005 levels. To the extent cash flows during 2006 are not sufficient to fund our capital obligations, we will utilize additional borrowings under our existing revolving credit facility. We currently have a borrowing base of $400 million with approximately $350 million utilized as of March 2, 2006.

In addition, we plan a high yield notes offering in the second quarter of 2006. The proceeds of this offering will be utilized to reduce borrowings under our revolving credit facility, which will provide additional liquidity. The notes would not be registered under the Securities Act or any state securities laws and may not be offered or sold in the United States absent registration or an applicable exemption from registration. We expect that the notes would be offered only to qualified institutional buyers under Rule 144A and non-U.S. persons under Regulation S. We anticipate that the terms of the notes would be no more restrictive than the terms of our credit facility.

The timing of expenditures (especially regarding deepwater projects) is unpredictable. Also, our cash flows are heavily dependent on the oil and natural gas commodity markets, and our ability to hedge oil and natural gas prices is limited by our revolving credit facility to no more than 80% of our expected production from proved developed producing reserves. If either oil or natural gas commodity prices decrease from their current levels, our ability to finance our planned capital expenditures could be affected negatively. Amounts available for borrowing under our revolving credit facility are largely dependent on our level of proved reserves and current oil and natural gas prices. Furthermore, we can provide no assurance that our planned high yield notes offering will be successful. If either our proved reserves or commodity prices decrease, amounts available to us to borrow under our revolving credit facility could be reduced. If our cash flows are less than anticipated or amounts available for borrowing under our revolving credit facility are reduced or we can not access the high yield or other debt markets, we may be forced to defer planned capital expenditures.

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

Our existing proved reserves are comprised of West Texas and Gulf of Mexico properties. The West Texas properties are relatively long-life in nature characterized by relatively low decline rates (lower productive rates) while the Gulf of Mexico properties are shorter-life in nature characterized by relatively high decline rates (higher productive rates). For the year ended December 31, 2005, our Gulf of Mexico properties comprised about 77% of our total production or

93% on a pro forma basis. We plan to maintain an active drilling program for our onshore properties with the intention of maintaining or increasing production in those areas. Although production from our existing offshore wells will decline more rapidly over time than our onshore wells, the percentage of production attributable to our offshore wells is expected to increase in the coming years as more of our undeveloped deep water projects commence production and we begin to exploit our newly acquired offshore assets. While we expect this trend to continue for the near future, oil and gas production (especially for our offshore properties) can be heavily affected by reservoir characteristics and unforeseen events (such as hurricanes and other casualties), so we can not predict with any certainty the timing of declines in production or the commencement of production from new projects.

In conjunction with the March 2004 merger, we established a new credit facility maturing on March 2, 2007. The new credit facility was fully drawn at inception for $135 million. In addition, we issued a $10 million promissory note to JEDI as part of the merger consideration. See Enron Related Matters and JEDI Term Promissory Note under Item 1. Net proceeds from a private equity placement were approximately $44 million, of which $6 million was used to pay down the JEDI promissory note with the remainder used to pay down the credit facility. The JEDI note was fully repaid at its maturity date of March 2, 2006.

For the years ended December 31, 2005 and 2004, our interest rate sensitivity for a change in interest rates of 1/8 percent on average outstanding debt under our credit facility is approximately $0.1 million and $0.1 million, respectively. The LIBOR rate on which our bank borrowings are primarily based was 4.69% as of March 2, 2006.

We had a net cash inflow of $2.0 million in 2005 compared to a net cash outflow of $57.6 million in 2004 and a net cash inflow of $41.8 million in 2003. A discussion of the major components of cash flows for these periods follows.

		Non-GAAP	**Post-Merger**	**Pre-Merger**	
	Year Ended December 31, 2005	**Combined Year Ended December 31, 2004**	**Period from March 3, 2004 to December 31, 2004**	**Period from January 1, 2004 to March 2, 2004**	**Year Ended December 31, 2003**
			(In millions)		
Cash flows provided by operating activities	$ 165.4	$ 155.5	$ 135.2	$ 20.3	$ 88.9

Cash flows provided by operating activities in 2005 increased by $9.9 million compared to 2004. The increase was primarily due to negative changes in working capital offset by lowered operating revenues. Cash flows provided by operating activities in 2004 increased by $66.6 million compared to 2003 primarily due to improved operating results and net income driven by increased production volumes and higher net oil and natural gas prices realized by Mariner.

		Non-GAAP	**Post-Merger**	**Pre-Merger**	
		Combined Year	**Period from March 3,**	**Period from**	

	Year Ended December 31, 2005	Ended December 31, 2004	2004 to December 31, 2004 (In millions)	January 1, 2004 to March 2, 2004	Year Ended December 31, 2003
Cash flows (used in) provided by investing activities	$ (247.8)	$ (148.3)	$ (133.0)	$ (15.3)	$ 52.9

Cash flows used in investing activities in 2005 increased by $99.5 million compared to 2004 due to increased capital expenditures in 2005. Cash flows used in investing activities in 2004 increased by

Table of Contents

$201.2 million compared to 2003 due to increased capital expenditures in 2004 and the sale of assets in prior years.

		Non-GAAP	Post-Merger	Pre-Merger	
	Year Ended December 31, 2005	Combined Year Ended December 31, 2004	Period from March 3, 2004 to December 31, 2004	Period from January 1, 2004 to March 2, 2004	Year Ended December 31, 2003
			(In millions)		
Cash flows (used in) provided by financing activities	$ 84.4	$ (64.9)	$ (64.9)		$ (100.0)

Cash flows provided by financing activities in 2005 were primarily the result of proceeds from a private equity offering in March 2005 ($44 million) and net borrowings under our revolving credit facility ($47 million). Cash flows used in financing activities in 2004 decreased by $35.1 million compared to 2003 as a result of a $166 million dividend to our former indirect parent used to help repay a term loan to an affiliate of Enron Corp. and the placement of our revolving credit facility.

Commodity Prices and Related Hedging Activities

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

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

Fixed Price Swaps	Quantity	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)

Table of Contents

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

Fixed Price Swaps	Quantity	Fixed Price	December 31, 2004 Fair Value Gain/(Loss) (In millions)
Crude Oil (Bbls)			
January 1 December 31, 2005	606,000	$ 26.15	$ (10.0)
January 1 December 31, 2006	140,160	29.56	(1.5)
Natural Gas (MMBtus)			
January 1 December 31, 2005	8,670,159	5.41	(7.0)
January 1 December 31, 2006	1,827,547	5.53	(1.9)
Total			$ (20.4)

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

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

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

	Year Ended December 31,		
	2005	2004	2003
		(Dollars in millions)	

Natural Gas			
Quantity settled (MMBtus)	15,917,159	18,823,063	25,520,000
Increase (Decrease) in Natural Gas Sales	$ (33.0)	$ (10.8)	$ (27.1)
Crude Oil			
Quantity settled (Mbbls)	836	1,554	730
Increase (Decrease) in Crude Oil Sales	$ (20.8)	$ (16.9)	$ (5.0)

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.

Table of Contents

Interest Rate Hedges

Borrowings under our revolving credit the facility, discussed below, 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.

Credit Facility

On March 2, 2006, at the closing of the merger with Forest Energy Resources, Mariner and Mariner Energy Resources, Inc. entered into a $500 million senior secured revolving credit facility, and an additional $40 million senior secured letter of credit facility. The revolving credit facility will mature on March 2, 2010, and the $40 million letter of credit facility will mature on March 2, 2009. We used borrowings under the revolving credit facility to facilitate the merger and to retire existing debt, and we may use borrowings in the future for general corporate purposes. The $40 million letter of credit facility has been used to obtain a letter of credit in favor of Forest to secure performance of our obligations under an existing drill-to-earn program.

The outstanding principal balance of loans under the revolving credit facility may not exceed the borrowing base, which has been initially set at $400 million. The borrowing base will be redetermined semi-annually by the lenders. In addition, the agent and Mariner may request one additional redetermination during the interval between each scheduled redetermination, and the agent may request redeterminations in connection with certain property dispositions that equal or exceed 5% of the then current borrowing base, certain gas imbalances that exceed $50 million, and certain bond issuances, which would include Mariner s proposed high yield debt offering (see Cash Flows and Liquidity). In addition, the borrowing base automatically reduces by an amount equal to 25% of the gross proceeds from such bond issuances. If the borrowing base falls below the outstanding balance under the revolving credit facility, we will be required to prepay the deficit, pledge additional unencumbered collateral, repay the deficit and cash collateralize certain letters of credit, or some combination of such prepayment, pledge, and repayment and collateralization.

Interest under the revolving credit facility is determined by reference to the following grid:

Applicable Margin

Usage as a % Borrowing Base	LIBOR Loans	Reference Rate Loans	Unused Fee
Less than 50%	1.25%	0.00%	0.375%
51% to 75%	1.50%	0.00%	0.375%
76% to 90%	1.75%	0.25%	0.250%
Greater than 90%	2.00%	0.5%	0.250%

Interest is payable quarterly for Union Bank of California Reference Rate loans and at the applicable maturity date for LIBOR (London interbank offered rate) loans. The fee for letters of credit issued under the revolving credit facility is the LIBOR margin indicated in the grid, per annum. The fee for letters of credit under the letter of credit facility is 1.50% due quarterly in advance.

The obligations under the credit facilities are secured by first priority liens on substantially all of our real and personal property, including our existing and after-acquired oil and gas properties and related real property interests.

Additionally, the obligations under the credit facilities are guaranteed by us and each of our subsidiaries.

The credit facilities contain various covenants that limit our ability to do the following, among other things:

- incur certain indebtedness;
- grant certain liens;
- merge or consolidate with another entity;

sell property or other assets which generate proceeds in excess of 5% of the then current borrowing base;

make certain loans or investments, or dividends or other payments in respect of equity or bonds; and

enter new lines of business.

The credit facilities also contain covenants, which, among other things, require us to maintain specified ratios as follows:

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

total debt to consolidated EBITDA of not more than 2.5 to 1.0.

If an event of default exists under the credit facilities, the lenders will be able to accelerate the maturity of the credit facilities and exercise other rights and remedies. Events of default include defaults in payment or performance under the credit facilities, misrepresentations, cross-defaults to other debt or material obligations, and insolvency, material adverse judgments, change of control (including certain changes in ownership and in the event Mr. Scott D. Josey ceases to be involved in Mariner s management, the failure to timely replace him with someone with comparable qualifications) and any material adverse change.

As of March 2, 2006, $350 million was utilized under the credit facility, and the weighted average interest rate was 7.75%.

JEDI Term Promissory Note

As part of the 2004 merger consideration payable to JEDI, we issued a term promissory note to JEDI in the amount of $10 million. The note 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 the interest in cash rather than in kind. The JEDI note was secured by a lien on three of our properties with no proved reserves located in the Gulf of Mexico. We 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 an event of default triggered by the occurrence of an event of default under our credit facility. We used $6 million of the proceeds from the 2005 private equity placement to repay a portion of the JEDI note. As of December 31, 2005, $4 million was still outstanding under the JEDI note. This note was repaid in full on its maturity date of March 2, 2006.

Table of Contents

Capital Expenditures and Capital Resources

The following table presents major components of our capital expenditures for each of the three years in the period ended December 31, 2005.

	Year Ended December 31, 2005	Combined Year Ended December 31, 2004	Post-Merger Period from March 3, 2004 to December 31, 2004	Pre-Merger Period from January 1, 2004 to March 2, 2004	Year Ended December 31, 2003
			(In millions)		
Capital expenditures:					
Leasehold acquisition	$ 11.5	$ 4.8	$ 4.4	$ 0.4	$ 4.8
Oil and natural gas exploration	50.0	43.0	35.9	7.1	26.8
Oil and natural gas development	121.7	88.6	82.0	6.6	44.3
Proceeds from property conveyances					(121.6)
Acquisitions	53.4	4.9	4.9		
Other items (primarily gathering system, capitalized overhead and interest)	16.1	7.6	6.4	1.2	7.4
Total capital expenditures, net of proceeds from property conveyances	$ 252.7	$ 148.9	$ 133.6	$ 15.3	$ (38.3)

Our net capital expenditures for 2005 increased by $103.8 million as compared to 2004, primarily as a result of increased acquisitions, primarily in West Texas, and increased expenditures on development activities. Our net capital expenditures for 2004 increased by $187.2 million, as compared to 2003, as a result of increased exploration and development expenditures with no offsetting proceeds from property conveyances in 2004.

We had no long-term debt outstanding as of December 31, 2003. As of December 31, 2005 and 2004, long-term debt was $156 million and $115 million, respectively. See Credit Facility.

63

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, 2005:

	Total	Less Than One Year	1-3 Years	3-5 Years	More Than 5 Years
			(In millions)		
Debt obligations(1)	$ 156.0	$ 4.0	$ 152.0	$	$
Interest obligations(2)	0.1	0.1			
Operating leases	7.4	1.2	2.8	2.4	1.0
Abandonment liabilities	49.5	11.4	4.0	12.1	22.0
Derivative liability	63.8	42.2	21.6		
Other liabilities	21.0	14.5	6.5		
Total contractual cash commitments	$ 297.8	$ 73.4	$ 186.9	$ 14.5	$ 23.0

(1) As of December 31, 2005, we had incurred debt obligations under our credit facility and the JEDI promissory note that are due as follows: $4 million in 2006; and $152 million in 2007. On March 2, 2006, we incurred an additional $176.2 million of debt in connection with the Forest Energy Resources merger. Our total debt as of March 2, 2006 was approximately $346 million under our amended and restated credit facility that extended the maturity date to March 2, 2010.

(2) Interest obligations represent approximately 12 months of interest due on the JEDI promissory note at 10%. Future interest obligations under our credit facility are uncertain, due to the variable interest rate on fluctuating balances. Based on a 7.15% weighted average interest rate on amounts outstanding under our credit facility as of December 31, 2005, $10.9 million and $1.8 million would be due under the credit facility in 2006 and 2007, respectively. Based on a 7.75% weighted average interest rate on amounts outstanding under our amended and restated credit facility as of March 2, 2006, $22.8 million, $81.7 million and $4.5 million would be due under the credit facility in less than one year, 1-3 years and 3-5 years, respectively.

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

December 31, 2005 was $16.0 million. For additional information concerning the contested royalty payments and the MMS s demands, see Legal Proceedings under Item 3.

Off-Balance Sheet Arrangements

Transportation Contract In 1999, Mariner constructed a 29-mile flowline from a third party platform to the Mississippi Canyon 674 subsea well. After commissioning, MEGS LLC, an Enron affiliate, purchased the flowline from Mariner and its joint interest partner. In addition, Mariner entered into a firm transportation contract with MEGS LLC at a rate of $0.26 per MMBtu to transport Mariner s share of approximately 130,000,000 MMbtus of natural gas from the commencement of production through March 2009. Mariner s working interest in the well is 51%. For the year ended December 31, 2003, Mariner paid $1.9 million on this contract. The remaining volume commitment was 14,707,107 MMbtus or $3.8 million net to Mariner. Pursuant

64

to the contract, Mariner was required to deliver minimum quantities through the flowline or be subject to minimum monthly payment requirements.

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

On March 2, 2006, Mariner obtained a \$40 million letter of credit under its senior secured letter of credit facility. The letter of credit was issued in favor of Forest to secure our performance of our obligations under an existing drill-to-earn program.

Recent Accounting Pronouncements

Recent Accounting Pronouncements In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 153, Exchanges of Nonmonetary Assets, an Amendment of APB Opinion No. 29, which provides that all nonmonetary asset exchanges that have commercial substance must be measured based on the fair value of the assets exchanged and any resulting gain or loss recorded. An exchange is defined as having commercial substance if it results in a significant change in expected future cash flows. Exchanges of operating interests by oil and gas producing companies to form a joint venture continue to be exempted. APB Opinion No. 29 previously exempted all exchanges of similar productive assets from fair value accounting, therefore resulting in no gain or loss recorded for such exchanges. SFAS No. 153 became effective for fiscal periods beginning on or after June 15, 2005. Accordingly, we adopted this statement effective June 30, 2005, and it did not have a material impact on our consolidated financial position, results of operations or cash flows.

In March 2005, the FASB issued Interpretation (FIN) No. 47, *Accounting for Conditional Asset Retirement Obligations,* which clarifies that an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation when the obligation is incurred generally upon acquisition, construction, or development and/or through the normal operation of the asset, if the fair value of the liability can be reasonably estimated. A conditional asset retirement obligation is a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Uncertainty about the timing and/or method of settlement is required to be factored into the measurement of the liability when sufficient information exists. We adopted FIN No. 47 on December 31, 2005 and it did not have a material impact on our consolidated financial position, results of operations or cash flows.

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections a replacement of APB Opinion No. 20 and FASB Statement No. 3.* SFAS No. 154 changes the requirements for the accounting and reporting of a change in accounting principle, including voluntary changes in accounting principle and changes required by an accounting pronouncement that does not include specific transition provisions. SFAS No. 154 requires retrospective application to prior period financial statements of changes in accounting principle. If impractical to determine either the period-specific effects or the cumulative effect of the change, the new accounting principle would be applied as if it were adopted prospectively from the earliest date practical. The correction of errors in prior period financial statements should be identified as a restatement. SFAS No. 154 is effective for fiscal years beginning after December 15, 2005. Accordingly, we adopted this statement effective January 1, 2006 and, upon adoption, it did not have a material impact on our consolidated financial position, results of operations or cash flows.

In September 2005, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty. EITF Issue 04-13 requires that purchases and sales of inventory with the same counterparty in the same line of business should be accounted for as a single non-monetary exchange, if entered into in contemplation of one another. The consensus is effective for inventory arrangements entered into, modified or renewed in interim or annual reporting periods beginning after March 15, 2006. We do not expect the adoption of this EITF Issue to have a material impact on our consolidated financial position, results of operations or cash flows.

Table of Contents

In February 2006, the FASB issued SFAS No. 155, Accounting for Certain Hybrid Financial Instruments an amendment of FASB Statements No. 133 and 140. SFAS No. 155 simplifies the accounting for certain hybrid financial instruments, eliminates the FASB s interim guidance which provides that beneficial interests in securitized financial assets are not subject to the provisions of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, and eliminates the restriction on the passive derivative instruments that a qualifying special-purpose entity may hold. SFAS No. 155 is effective for all financial instruments acquired or issued after the beginning of an entity s first fiscal year that begins after September 15, 2006. We do not expect this Statement to have a material impact on our consolidated financial position, results of operations or cash flows.

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

For a discussion of our market risk, See Liquidity and Capital Resources Commodity Prices and Related Hedging Activities and Liquidity and Capital Resources Interest Rate Hedges in Item 7.

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

Index to Financial Statements

Table of Contents

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. (the Company) as of December 31, 2005 and 2004 and the related consolidated statements of operations, stockholders equity and comprehensive income and cash flows for the year ended December 31, 2005, for the period January 1, 2004 through March 2, 2004 (Pre-merger), for the period from March 3, 2004 through December 31, 2004 (Post merger), and for the year ended December 31, 2003 (Pre-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. as of December 31, 2005 and 2004, and the results of its operations and cash flows for the year ended December 31, 2005, for the period January 1, 2004 through March 2, 2004 (Pre-merger), for the period from March 3, 2004 through December 31, 2004 (Post merger), and for the year ended December 31, 2003 (Pre-merger) in conformity with accounting principles generally accepted in the United States of America.

The Company changed its method of accounting for asset retirement obligations in 2003. This change is discussed in Note 1 to the Consolidated Financial Statements.

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.