HOUSTON EXPLORATION CO
Form 10-K
February 28, 2007

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2006

OR

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

For the transition period from __________ to __________

Commission File No. 001-11899

THE HOUSTON EXPLORATION COMPANY
(Exact name of registrant as specified in its charter)

Delaware	**22-2674487**
(State or Other Jurisdiction of Incorporation or Organization)	**(IRS Employer Identification No.)**
1100 Louisiana, Suite 2000 Houston, Texas	**77002-5215**
(Address of Principal Executive Offices)	**(Zip Code)**

(713) 830-6800
(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, $0.01 par value	New York Stock Exchange
Series A Junior Participating Preferred Stock, $0.01 par value	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: None

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the 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 Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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. Yes þ No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

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

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

The aggregate market value of common stock held by non-affiliates of the registrant was approximately $1.710 billion, based on the closing sales price of $61.19 per share of the registrant s common stock as reported by on the New York Stock Exchange as of June 30, 2006, the last business day of the registrant s most recently completed second fiscal quarter. As of February 28, 2007, 28,155,996 shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant s Proxy Statement for the Annual Meeting of Stockholders to be held May 22, 2007 are incorporated by reference into Part III of this Form 10-K. If such Proxy Statement is not filed within 120 days after December 31, 2006, the Part III information will be filed as part of an amendment to this Form 10-K not later than the end of such 120-day period, pursuant to General Instruction G(3).

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Forward-Looking Statements

Certain statements in this Annual Report on Form 10-K (Annual Report) and the documents we have incorporated by reference into this Annual Report, other than purely historical information, including estimates, projections, statements relating to our business plans, strategies, objectives and expected operating results, and the assumptions upon which those statements are based, are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended (the Securities Act), and Section 21E of the Securities Exchange Act of 1934, as amended, (the Exchange Act). These forward-looking statements generally may be identified by the words believe, project, expect, anticipate, estimate, intend, str plan, target, pursue, may, will, would, will continue, will likely result, and similar expressions. Forward statements are based on current expectations and assumptions that are subject to risks and uncertainties which may cause actual results to differ materially from the forward-looking statements. A detailed discussion of these and other risks and uncertainties that could cause actual results and events to differ materially from such forward-looking statements is included in Item 1A. Risk Factors beginning on page 14 of this Annual Report. We undertake no obligation to update or revise publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

Available Information

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are made available free of charge on our web site at http://www.houstonexploration.com as soon as reasonably practicable after we electronically file such material with, or otherwise furnish it to, the Securities and Exchange Commission (SEC).

On January 7, 2007, we announced that we had entered into a definitive agreement and plan of merger with Forest Oil Corporation pursuant to which Forest will acquire all of the outstanding shares of Houston Exploration for a combination of cash and Forest common stock. On February 8, 2007, Forest filed a registration statement on Form S-4 with the SEC, including a preliminary joint proxy statement / prospectus with respect to the merger. Investors are urged to carefully read the information contained in the materials regarding the proposed transaction once the registration statement is declared effective and the joint proxy statement is mailed to stockholders. Investors may obtain a copy of the joint proxy statement / prospectus, free of charge, at the SEC s web site at www.sec.gov.

We have adopted an Ethical Business Conduct Policy Statement to provide guidance to our directors, officers and employees on matters of business conduct and ethics, including compliance standards and procedures. We also have adopted a Code of Ethics for Senior Financial Officers that applies to our principal executive officer, principal financial officer, principal accounting officer and controller. Our Ethical Business Conduct Policy Statement and Code of Ethics for Senior Financial Officers are available on the Shareholder/Financial section of our web site at www.houstonexploration.com under the heading Corporate Governance. We intend to promptly disclose via a Current Report on Form 8-K or via an update to our web site information any amendment to or waiver of these codes with respect to our executive officers and directors. Waiver information disclosed via the web site will remain on the web site for at least 12 months after the initial disclosure of a waiver. Our Corporate Governance Guidelines and the charters of our Audit Committee, Nominating and Governance Committee, and Compensation and Management Development Committee are also available on the Shareholder/Financial section of our web site at www.houstonexploration.com under the heading Corporate Governance. In addition, copies of our Ethical Business Conduct Policy Statement, Code of Ethics for Senior Financial Officers, Corporate Governance Guidelines and the charters of the Committees referenced above are available at no cost to any stockholder who requests them by writing or telephoning us at the following address or telephone number:

The Houston Exploration Company
1100 Louisiana Street, Suite 2000
Houston, TX 77002 5215
Attention: Corporate Secretary
Telephone: (713) 830-6800

Information contained on or connected to our web site is not incorporated by reference into this Annual Report and should not be considered part of this report or any other filing that we make with the SEC.

In this Annual Report, unless the context requires otherwise, when we refer to we, us and our, we are describing The Houston Exploration Company including, through May 31, 2004, our former subsidiary Seneca-Upshur Petroleum, Inc., and subsequent to October 8, 2004, THEC, LLC and THEC, LP on a consolidated basis.

If you are not familiar with the natural gas and oil terms used in this Annual Report, please refer to the explanations of the terms under the caption Glossary of Natural Gas and Oil Terms beginning on page G-1.

When we refer to equivalents, we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one barrel of oil is equal to six thousand cubic feet of natural gas.

Part I.

Items 1. and 2. Business and Properties

Overview of Our Business and Pending Merger

We are an independent natural gas and oil producer engaged in the exploration, development, exploitation and acquisition of natural gas and oil reserves in North America. We were founded in December 1985 as a Delaware corporation and wholly-owned subsidiary of our then parent company, KeySpan Corporation. We completed our initial public offering in September 1996. Through three separate transactions, the last of which occurred in November 2004, KeySpan completely divested of its ownership in the common stock of our company. As of December 31, 2006, our operations were concentrated in four producing regions within the United States: South Texas; the Arkoma Basin of Arkansas and Oklahoma; East Texas; and the Uinta and DJ Basins of the Rocky Mountains.

Our total net proved reserves as of December 31, 2006 were 699 billion cubic feet equivalent, or Bcfe. All of our reserves are estimated on an annual basis by independent petroleum engineers. Approximately 67% of our proved reserves at December 31, 2006, were classified as proved developed. During 2006, we produced 88.2 Bcfe. Production volumes during 2006 were significantly impacted by the sale of substantially all of our Gulf of Mexico assets during the first and second quarters of 2006 and continued curtailments of certain of these offshore fields prior to their sale, primarily as a result of infrastructure damage to third party pipelines and processing facilities caused by Hurricanes Katrina and Rita that hit the Louisiana and Texas coasts in August and September 2005.

In November 2005, we announced a strategic plan to restructure the company by pursuing the sale of our Gulf of Mexico assets, shifting our operating focus primarily onshore and repurchasing up to $200 million of our outstanding common stock. On March 31, 2006, we completed the sale of the Texas portion of our Gulf of Mexico assets and on June 1, 2006, we completed the sale of substantially all of our Louisiana Gulf of Mexico assets. The divestiture of these assets had a significant impact on our operating results for the year ended December 31, 2006 and on the comparability of those results to prior years.

On June 12, 2006, we received an unsolicited proposal from JANA Partners LLC, a hedge fund, to acquire our company for $62 per share, subject to due diligence and negotiation of required documentation. According to its public filings, JANA Partners beneficially owned approximately 12.3% of our outstanding common stock as of the date of the proposal. On June 26, 2006, we announced our Board of Directors determination that the unsolicited proposal made by JANA Partners was not in the best interest of our shareholders and that Lehman Brothers Inc. had been engaged to assist us in exploring a broad range of strategic alternatives to further enhance shareholder value. In connection with our review of strategic alternatives, Lehman assisted our Board in soliciting third party indications of interest for proposed business combination transactions with Houston Exploration. During the solicitation and review period, forward natural gas prices declined significantly. Further details regarding the strategic alternatives review process will be available in the joint proxy statement / prospectus, and the registration statement on Form S-4 of which it is a part, to be mailed to our stockholders and referred to herein under the caption Available Information.

On January 7, 2007, we announced the conclusion to the strategic alternatives review process with our entry into an agreement and plan of merger with Forest Oil Corporation. Under the merger agreement, Forest will acquire all of the outstanding shares of Houston Exploration for a combination of cash and Forest common stock.

Under the terms of the merger agreement, our shareholders will receive total consideration equal to 0.84 shares of Forest common stock and $26.25 in cash for each outstanding share of Houston Exploration common stock, or an aggregate of an estimated 23.6 million shares of Forest common stock and cash of $740 million. Based on the closing price of Forest common stock on January 5, 2007, the last trading day prior to announcement of the transaction, this represents $52.47 per share of merger consideration to be received by Houston Exploration shareholders. The actual value of the merger consideration to be received by our shareholders will depend on the average closing price of

Forest common stock for the ten trading days ending three calendar days prior to the effective date of the merger, and the amount of cash and stock consideration will be determined by shareholder elections, subject to proration and an equalization formula. It is anticipated that the stock portion of the consideration will be tax free to Houston Exploration shareholders.

The Boards of Directors of Houston Exploration and Forest each unanimously approved the proposed merger. The merger is subject customary terms and conditions, including the approval of both Houston Exploration and Forest shareholders, and is expected to be completed in the second quarter of 2007. Upon completion of the transaction, it is anticipated that Forest shareholders would own approximately 73% of the combined company, and Houston Exploration shareholders would own approximately 27%.

Concurrently with the execution of the merger agreement, funds affiliated with JANA Partners entered into a voting agreement with Forest pursuant to which the JANA funds agreed, during the term of the voting agreement, to vote their shares of our common stock in favor of the merger with Forest and the adoption of the merger agreement and against any transaction that would impede or delay the merger with Forest, and granted to Forest a proxy to vote their shares at any stockholder meeting convened to consider such matters. As of January 7, 2007, the JANA funds beneficially owned approximately 14.7% of our total issued and outstanding shares of our common stock. The voting agreement will terminate in certain instances, including an adverse recommendation change (as defined in the merger agreement) by our Board of Directors or any material amendment to the merger agreement that is adverse to us or our stockholders.

On February 8, 2007, Forest filed a registration statement on Form S-4 with the SEC, including a preliminary joint proxy statement / prospectus with respect to the merger. Also on February 8, 2007, the companies received notice of early termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvement Act with respect to the proposed transaction.

Business Strategy

Our goal is to create and maximize shareholder value by growing and/or optimizing reserves, production and cash flow, while maintaining financial flexibility. To grow our business, we invest primarily in natural gas projects within areas where we are presently successful or where we believe our organization s skill set can produce successful results. To accomplish our goal, pending the merger, we employ the following strategies:

Pursue Balanced Growth. We pursue a balanced strategy of exploiting our existing reserves, exploring for new reserves and acquiring new properties. Typically, a substantial portion of our annual capital expenditure program is dedicated to lower risk exploitation and development projects intended to generate cash flows with which we can fund future expansion opportunities. We supplement our exploitation activities by investing in exploratory prospects. We enhance our exploration and exploitation activities with acquisitions of new projects that we believe offer significant unexploited reserve potential and that conform to our investment criteria and operating philosophy. However, the merger agreement contains significant restrictions on our operations pending completion of the merger, including restrictions, among others, on our ability to make capital expenditures, including acquisitions, enter into hedging arrangements and take other specific actions without Forest s approval.

Focus on Natural Gas. Our assets are concentrated in natural gas prone areas in the United States, and our production and reserve base is primarily natural gas. As of December 31, 2006, approximately 96% of our proved reserves were natural gas and, for the year ended December 31, 2006, approximately 94% of our production was natural gas. On an equivalent unit of production basis, lease operating expense is typically lower for natural gas properties as compared to oil properties, thereby allowing a higher cash margin.

Concentrated Operations. We focus our operations in four relatively concentrated areas in order to more efficiently utilize our base of geological, engineering, drilling and production experience and expertise in these regions. By concentrating our operations, we believe we are able to manage a large asset base with a relatively small number of employees and to integrate additional properties at relatively low incremental costs. At December 31, 2006, approximately 99% of our reserves were located in four geographic areas: South Texas, the Arkoma Basin, East Texas and the Rocky Mountains.

Maintain Significant Operating Control. Whenever possible, we prefer to operate our properties, as it gives us more control over the nature and timing of capital expenditures and overall operating expenses. At

December 31, 2006, we operated approximately 80% of our wells, and our average working interest was approximately 77%.

Minimize Costs. We seek to minimize operating costs through the concentration of assets within geographic areas where we can leverage our operating control and capture operating efficiencies. We believe that our operating structure provides us with a competitive advantage because it maximizes our margins and cash flows. For 2006, our onshore lease operating expense was $0.63 per Mcfe.

Employ Conservative Financial Policies. We typically have funded our exploitation and exploration activities out of cash flows from operations, while we have funded acquisitions with borrowings under our revolving bank credit facility and through public debt offerings. Although our debt levels have historically increased periodically in connection with acquisitions, we will seek to maintain conservative debt levels. Among other things, this will

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provide us with flexibility to continually review and adjust our capital expenditure program during the year (subject to the restrictions in the merger agreement) based on operational developments, commodity prices, service costs, acquisition opportunities and numerous other factors.

Manage Commodity Price Risks. We have historically entered into derivative instruments which were intended to reduce our exposure to adverse commodity price fluctuations and provide more predictable cash flows that allow us to better plan and fund our capital expenditure program. While the use of derivative instruments has prevented us from realizing the full benefit of upward price movements and may continue to do so in the future, we believe that price volatility is likely to continue and that we can use this volatility to our benefit (subject to the restrictions in the merger agreement) by locking in prices when they reach levels we determine to be acceptable.

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Properties and Operating Areas

The table below summarizes certain data for our core operating areas for the year ended December 31, 2006:

	Activity and Balances as of or for the Year Ended December 31, 2006					
Area	**Average Daily Production** (MMcfe/d)	**Total Production** (MMcfe)	**Proved Reserves** (MMcfe)	**Percentage Total Proved Reserves**	**Wells Drilled Total** (Gross)	**Wells Drilled Successful** (Gross)
South Texas	143	52,317	356,023	51%	100	90
Arkoma Basin	40	14,465	190,384	27%	72	71
East Texas	12	4,420	86,086	12%	28	28
Rocky Mountains	8	2,961	62,062	10%	160	138
Other	1	244	2,563			
Total onshore	204	74,407	697,118	100%	360	327
Gulf of Mexico	38	13,749	2,210		3	2
Total	242	88,156	699,328	100%	363	329

South Texas. Our South Texas properties are concentrated in the Charco, North Roleta, Haynes and South Trevino Fields of Zapata County; the Alexander, Hubbard, South Laredo and Vaquillas Ranch Fields of Webb County; the Northeast Thompsonville Field in Jim Hogg County, the Rincon Field in Starr County, the Tijerina-Canales-Blucher Field in Jim Wells and Kleberg Counties, and the San Carlos Field in Hidalgo County.

As of December 31, 2006, our South Texas properties covered approximately 83,000 net acres and we owned interests in 955 producing wells, 840 (88%) of which we operated. Our average working interest is 84%. Well depths range from 5,000 to 17,000 feet with production from the Frio, Vicksburg and Wilcox formations. During 2006, production from our South Texas properties averaged 143 MMcfe per day and accounted for 59% of our total production. At December 31, 2006, estimated net proved reserves totaled approximately 356 Bcfe, which accounted for approximately 51% of our reserve base at year-end 2006.

Arkoma Basin. Our Arkoma Basin properties are located in two primary areas: the Chismville/Massard Field located in Logan and Sebastian Counties of Arkansas and the Wilburton and South Panola Fields located in Latimer County, Oklahoma. At December 31, 2006, we had approximately 39,000 net acres under lease and we owned working interests in 483 producing natural gas wells, 350 (72%) of which we operated. Our average working interest is 56%. Wells average a depth of 5,500 feet, and production is from the Atoka formation. During 2006, production averaged 40 MMcfe per day. Acquisition opportunities have been scarce or limited in the Arkoma Basin during the most recent three-year period, and as a result, our current activities are primarily focused on the substantial number of in-field drilling opportunities within our existing acreage. At December 31, 2006, estimated net proved reserves totaled approximately 190 Bcfe, which accounted for approximately 27% of our reserve base at year-end 2006.

East Texas. Our East Texas properties are concentrated in the Willow Springs Field located in Gregg County, the North Blocker Field in Harrison County and the South Oak Hill Field in Rusk County, Texas. In 2006, we continued the expansion of our East Texas operating base initiated during 2005 with the acquisition of producing properties and acreage in the Willow Springs Field, adding approximately 16.2 Bcfe of net proved reserves for $21.3 million. As of December 31, 2006, our East Texas properties covered approximately 17,000 net acres, and we owned interests in 107 producing wells, 101 (94%) of which we operated. Our average working interest is 87%. During 2006, production averaged approximately 12 MMcfe per day. At December 31, 2006, estimated net proved reserves totaled approximately 86 Bcfe, which accounted for approximately 12% of our reserve base at year-end 2006.

Rocky Mountains. Our Rocky Mountain properties are primarily located in the Uinta Basin of Northeastern Utah and the DJ Basin in Eastern Colorado. At December 31, 2006, we had accumulated approximately 739,000 net acres with estimated net proved reserves of 62 Bcfe, an increase of approximately 35 Bcfe or nearly 130% from net proved reserves of approximately 27 Bcfe at the end of 2005. During 2006, production from our Rocky Mountain properties averaged approximately 8 MMcfe per day, net to our interests. At December 31, 2006, we had interests in 214 wells, all of which are operated by us, along the Niobrara Trend of the DJ Basin, with an average working interest of 100%; 107 wells in the Uinta Basin, with an average working interest of 56%, of which 13 (12%) are operated by us; and one exploratory well, with a working interest of 50% and operated by us, in the Williston Basin of northwestern North Dakota.

Gulf of Mexico. During the first and second quarters of 2006, we completed the sale of substantially all of our Gulf of Mexico assets. The sale transactions did not include 18 Louisiana offshore blocks retained by us. Of these 18 blocks, four expired subsequent to the sales transactions, two were drilled during 2006, resulting in two successful exploratory wells, and 12 remain classified as undeveloped at the end of 2006. During 2006, we participated in drilling three offshore exploratory wells: Eugene Island 357 No. 1 was unsuccessful; West Cameron 39 No. A2 was successfully completed and brought on-line in late June 2006; and West Cameron 132 No. 1 was successfully drilled during the third quarter of 2006, with initial production projected during the first half of 2007. During December 2006, production from our remaining offshore wells averaged approximately 1 MMcfe per day.

Other. As of December 31, 2006, our other operating areas primarily consist of interests in one field in Central Mississippi. The Oakvale Dome Field is located in Jefferson Davis County and has two producing wells, both of which are non-operated. Production averaged approximately 1 MMcfe per day during 2006. In addition to our interests in the Oakvale Dome Field, we have interests or rights of an immaterial nature in other prospective properties or projects with respect to which no reserves are currently associated, and may make future investments of immaterial amounts in similar such projects in the future.

Natural Gas and Oil Reserves

The following table summarizes the estimates of our historical net proved reserves as of December 31, 2006, 2005 and 2004, and the present values attributable to those reserves at those dates. For the years ended December 31, 2006 and 2005, all of the reserve data and present values were estimated by independent petroleum engineering consultants Netherland, Sewell & Associates, Inc. For the year ended December 31, 2004, all of the reserve data and present values were estimated by two independent petroleum engineering firms: Netherland, Sewell & Associates, Inc. and Miller and Lents, Ltd., with these firms evaluating approximately 80% and 20%, respectively, of the total reserve quantities.

	As of December 31,		
Net Proved Reserves:	**2006**(1)	**2005**(1)	**2004**(1)
		(in thousands)	
Natural gas (MMcf)	671,636	793,074	749,114
Oil and natural gas liquids (MBbls)	4,615	11,291	7,335
Total (MMcfe)	699,328	860,820	793,124
Net present value of future cash flows, before income taxes(2)(4)	$ 1,002,692	$ 2,877,420	$ 2,071,976
Future income taxes, discounted at 10%	(265,466)	(910,396)	(631,921)
Standardized measure of discounted future net cash flows (3)(4)	$ 737,226	$ 1,967,024	$ 1,440,055

(1) At December 31, 2006, 2005 and 2004, net proved reserves attributable to our Gulf of Mexico assets totaled 2,210 MMcfe, 244,596 MMcfe and 291,477 Mcfe, respectively, and included

2,070 MMcf of natural gas and 23 MBbls of oil and natural gas liquids for 2006, 196,488 MMcf of natural gas and 8,018 MBbls of oil and natural gas liquids for 2005, and 250,383 MMcf of natural gas and 6,849 MBbls of oil and natural gas liquids for 2004. Substantially all of our Gulf of Mexico assets were sold during 2006.

(2) The net present value of future net cash flows before income tax expense attributable to estimated net proved reserves, discounted at 10% per annum (PV10), is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. PV10 is not a measure of financial performance under accounting principles generally accepted in the United States

(GAAP). However, we consider PV10 to be an important measure for evaluating the relative significance of our natural gas and oil properties. PV10 is computed on the same basis as the standardized measure of discounted future net cash flows, but without deducting income taxes. We believe investors and creditors may utilize our PV10 as a basis for comparison of the relative size and value of our reserves to other companies. The above table provides a reconciliation of PV10 to the standardized measure; however, PV10 is not a substitute for the standardized measure.

(3) The standardized measure of discounted future net cash flows has been

calculated in accordance with Statement of Financial Accounting Standards (SFAS) 69, Disclosures about Oil and Gas Producing Activities. Additional information on the standardized measure is presented in Consolidated Financial Statements, Note 12 Supplemental Information on Natural Gas and Oil Exploration, Development and Production Activities (Unaudited) and, in accordance with current SEC guidelines, does not include estimated future cash flows from our open derivative instruments.

(4) Year-end prices per Mcf of natural gas used in making the present value and standardized measure determinations as of December 31, 2006, 2005 and

2004 were $4.94, $8.15 and $5.68, respectively. Year-end prices per Bbl of oil used in making these same calculations were $49.94, $53.27 and $41.67, respectively, for 2006, 2005 and 2004. These prices should not be interpreted as a prediction of future prices, and our PV10 measure and the standardized measure do not purport to represent the fair value of our natural gas and oil reserves.

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Proved natural gas and oil reserves are the estimated quantities of natural gas, crude oil and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. In accordance with applicable requirements of the SEC, we estimate net proved reserves and future net revenues using sales prices estimated to be in effect as of the date we make the reserve estimates. Sales price estimates are held constant throughout the life of the properties, except to the extent a contract specifically provides for escalation. Natural gas and oil prices have fluctuated widely in recent years, and volatility is expected to continue. Future prices and costs may be materially higher or lower than prices and costs as of the date of any estimate. Price fluctuations will directly affect estimated quantities of proved reserves and future net revenues. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control.

The reserve data contained in this Annual Report represent only estimates. Reservoir engineering is a complex and subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates prepared by one engineer may vary from those prepared by another. Estimates are subject to revision based on numerous factors including reservoir performance, prices and economic conditions. In addition, results of drilling, testing and actual production subsequent to the date of estimate may justify revision of that estimate. Revisions to prior estimates may be material. Reserve estimates are often different from the quantities of natural gas and oil that we are ultimately able to recover and are highly dependent upon the accuracy of the underlying assumptions. Our estimated proved reserves have not been filed with or included in reports to any federal agency. See Item 1A. Risk Factors *Estimates of proved reserves and future net revenues may change if the assumptions on which such estimates are based prove to be inaccurate.*

Drilling Activity

We engage in drilling activities on our properties. The following table sets forth the results of our drilling activities for the years ended December 31, 2006, 2005 and 2004. Gross wells are the sum of all wells in which we owned an interest. Net wells are the sum of our working interests in the gross wells.

	Exploratory Wells				**Development Wells**				**Total Wells**					
	Successful		**Dry**		**Successful**		**Dry**		**Successful**		**Dry**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
2006														
South Texas	1	1.0			89	76.1	10	8.6	90	77.1	10	8.6	100	85.7
Arkoma Basin	3	1.2			68	44.5	1	0.3	71	45.7	1	0.3	72	46.0
East Texas					28	26.2			28	26.2			28	26.2
Rocky Mountains	18	8.8	6	3.2	120	95.0	16	13.8	138	103.8	22	17.0	160	120.8
Gulf of Mexico	2	0.5	1	0.2					2	0.5	1	0.2	3	0.7
Total	24	11.5	7	3.4	305	241.8	27	22.7	329	253.3	34	26.1	363	279.4
2005														
South Texas	1	1.0			81	79.8	13	13.0	82	80.8	13	13.0	95	93.8
Arkoma Basin					60	36.8	1	0.8	60	36.8	1	0.8	61	37.6
East Texas					16	16.0			16	16.0			16	16.0
Rocky Mountains	128	96.4	21	15.7					128	96.4	21	15.7	149	112.1

Gulf of Mexico	5	2.4	2	1.3	7	6.1	1	0.5	12	8.5	3	1.8	15	10.3
Total	134	99.8	23	17.0	164	138.7	15	14.3	298	238.5	38	31.3	336	269.8
2004														
South Texas			1	1.0	56	54.6	19	18.0	56	54.6	20	19.0	76	73.6
Arkoma Basin					73	45.8	6	3.0	73	45.8	6	3.0	79	48.8
Rocky Mountains	26	25.4	3	2.3	2	2.0			28	27.4	3	2.3	31	29.7
Other			1	0.5	5	5.0			5	5.0	1	0.5	6	5.5
Gulf of Mexico	3	1.4	4	2.2	12	9.3			15	10.7	4	2.2	19	12.9
Total	29	26.8	9	6.0	148	116.7	25	21.0	177	143.5	34	27.0	211	170.5

As of December 31, 2006, we were drilling or participating in the drilling of 29 gross (18.8 net) wells. Of these wells, through February 28, 2007, 18 gross (12.0 net) wells have been determined to be successful; 4 gross (3.3 net) wells were dry; and the remaining 7 gross (3.5 net) wells were still in progress as of the date of this Annual Report.

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Productive Wells

The following table sets forth the number of productive wells in which we owned an interest as of December 31, 2006. Productive wells consist of producing wells and wells capable of production, including 39 wells located in the Rocky Mountains (32 in the DJ Basin, six in Uinta and one in North Dakota) awaiting connections at December 31, 2006. Wells that are completed in more than one producing horizon are counted as one well. Where we are operator, we are responsible for managing the day-to-day operations of the well.

	As of December 31, 2006									
	Natural Gas Wells				Oil Wells				Total Wells	
	Operated		Non-Operated		Operated		Non-Operated			
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
South Texas	827	779.8	115	17.2	13	7.7			955	804.7
Arkoma Basin	350	240.3	133	29.1					483	269.4
East Texas	98	89.3	5	0.8	3	2.1	1	0.4	107	92.6
Rocky Mountains	228	227.5	92	45.4			2	1.0	322	273.9
Other			2	1.1					2	1.1
Total onshore	1,503	1,336.9	347	93.6	16	9.8	3	1.4	1,869	1,441.7
Gulf of Mexico			2	0.5					2	0.5
Total	1,503	1,336.9	349	94.1	16	9.8	3	1.4	1,871	1,442.2

Acreage Data

The following table sets forth the approximate developed and undeveloped acreage in which we held a leasehold mineral or other interest as of December 31, 2006. Undeveloped acreage includes leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas or oil, regardless of whether or not the acreage contains proved reserves. Gulf of Mexico acreage includes leases in federal and state waters.

	As of December 31, 2006					
	Undeveloped		Developed		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
South Texas	9,066	8,649	98,892	74,206	107,958	82,855
Arkoma Basin	27,181	10,216	47,239	28,619	74,420	38,835
East Texas	4,849	2,984	15,941	13,816	20,790	16,800
Rocky Mountains	906,621	687,032	78,914	51,668	985,535	738,700
Other onshore			1,740	620	1,740	620
Total onshore	947,717	708,881	242,726	168,929	1,190,443	877,810
Gulf of Mexico	56,998	31,936	7,500	750	64,498	32,686
Total	1,004,715	740,817	250,226	169,679	1,254,941	910,496

Undeveloped Acreage Expirations

The table below summarizes by year and area our undeveloped acreage scheduled to expire in the next five years:

	As of December 31, 2006									
	2007		2008		2009		2010		2011	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
South Texas	2,593	2,545	1,238	1,161	3,528	3,457				
Arkoma Basin	2,816	932			614	238	4,088	1,154	15,754	6,994
East Texas	2,799	2,172	126	126	191	169				
Rocky Mountains	66,529	56,971	317,773	181,999	36,012	28,117	15,719	7,145	132,708	120,326
Total onshore	74,737	62,620	319,137	183,286	40,345	31,981	19,807	8,299	148,462	127,320
Gulf of Mexico	5,000	2,500	11,998	4,437	25,000	12,500	15,000	12,500		
Total	79,737	65,120	331,135	187,723	65,345	44,481	34,807	20,799	148,462	127,320

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Marketing and Customers

We market the majority of the natural gas and oil production from properties we operate for both our account and the account of the other working interest owners in these properties. We typically sell a substantial portion of our production under short-term (usually one-month) contracts tied to a local price index. We do not have any material long-term, fixed price sales contracts. The remaining portion of our production is sold on a daily basis into local spot markets in order to accommodate fluctuations in daily production volumes. We normally sell production to a relatively small number of customers, as is customary in the exploration, development and production business. However, based on the current demand for natural gas and oil, we believe that the loss of any one or all of our major purchasers would not have a material adverse effect on our financial condition or results of operations. For a list of purchasers that accounted for 10% or more of our natural gas and oil revenues during the preceding last three calendar years, see Consolidated Financial Statements, Note 8 Sales to Major Customers.

Historically, we have entered into derivative contracts with counterparties who are participants in our bank credit facility, as well as unaffiliated third parties, for significant portions of our natural gas production. For a more detailed discussion, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

We incur gathering and transportation expenses to move our natural gas from the wellhead to a purchaser-specified delivery point. These expenses vary based on the volume and distance shipped, and the fee charged by the third party transporter. We do not have any material transportation agreements and we have not contracted for firm capacity for which we would pay monthly demand charges. Our natural gas and oil are transported through third party gathering systems and pipelines. Transportation space on these gathering systems and pipelines occasionally is limited and at times unavailable because of repairs or improvements, or as a result of priority transportation agreements with other gas shippers. While our ability to market our natural gas has only been infrequently limited or delayed, if transportation space is restricted or is unavailable, our cash flow from the affected properties could be adversely affected. See the section entitled Item 1A. Risk Factors *Our business depends on oil and natural gas transportation facilities that are owned by others.*

Title to Properties

As is customary in the oil and gas industry, we initially conduct only a cursory review of the title to undeveloped acreage in farm-out agreements and natural gas and oil leases. Prior to the commencement of drilling operations, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects, we, rather than the seller/lessor of the undeveloped property, are typically responsible for curing those defects at our expense. If we were unable to remedy or cure any title defect of a nature such that it would not be prudent to commence drilling operations on the property, we could suffer a loss of our entire investment in the property. Prior to completing an acquisition of producing natural gas and oil leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain title opinions. Our natural gas and oil properties are subject to customary royalty and other interests, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect our carrying value of the properties.

Competition

We encounter intense competition from other oil and gas companies in all areas of our operations, including the acquisition of additional properties and acreage. This competition has intensified in response to rising natural gas price levels and the natural maturation of several of our key fields. Our competitors include major integrated oil and gas companies and numerous independent oil and gas companies, individuals and drilling and income programs. Many of our competitors are large, well-established companies with substantially greater capital resources than our own. Our ability to acquire additional properties and to discover new reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. See Item 1A. Risk Factors *We face strong competition.*

Seasonal Nature of Business

Generally, but not always, demand for natural gas increases during the winter months as a result of heating applications and decreases during the summer and early fall. Seasonal anomalies such as mild winters or cool summers sometimes lessen these fluctuations. In addition, as the industrial use of natural gas has expanded in recent years, weather related demand and seasonal fluctuations are diminishing. However, seasonal weather conditions, such as severe tropical storms and hurricanes in the Gulf of Mexico and winter weather in the Rocky Mountain region can pose challenges for meeting our well drilling and production objectives.

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Employees

As of December 31, 2006, we had 160 full time employees, 125 of whom are located at our headquarters in Houston, Texas and the remainder of whom are located in our South Texas, Arkansas, Denver and East Texas field offices. None of our employees are represented by a labor union or other collective bargaining arrangement. We employ the services of independent consultants and contractors to perform various professional services, particularly in the areas of construction, design and well-site surveillance, permitting and environmental assessment. At our direction, independent contractors usually perform field and on-site production operation services, including pumping, maintenance, dispatching, inspection and testing. As of December 31, 2006, we had approximately 18 contract employees.

Offices

Our corporate offices are located at 1100 Louisiana Street, Suite 2000, Houston, Texas 77002. Our telephone number is (713) 830-6800. We maintain field operations and other offices in South Texas, Arkansas, East Texas and Colorado. We currently lease approximately 114,000 square feet of office space in Houston, Texas, at 1100 Louisiana Street, where our principal offices are located. We also lease approximately 2,250 square feet of office space in Denver, Colorado, at 700 17th Street.

Regulation

The oil and gas industry is extensively regulated by numerous federal, state and local authorities, including Native American tribes. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, and Native American tribes are authorized by statute to issue rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and gas industry increases our cost of doing business and, consequently, affects our profitability, generally, these burdens do not appear to materially affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Drilling and Production. Our operations are subject to various types of regulation at federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties, municipalities and Native American tribe jurisdictions, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the rates of production or allowables;
- the surface use and restoration of properties upon which wells are drilled; and
- the plugging and abandoning of wells.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and gas wells generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Our properties located in federal waters are regulated by the Minerals Management Service and are not subject to regulation by state agencies.

We conduct our operations in the Gulf of Mexico on oil and natural gas leases that are granted by the U.S. federal government and are administered by the Minerals Management Service. The Minerals Management Service issues leases through competitive bidding. The lease contracts contain relatively standardized terms and require compliance with detailed regulations of the Minerals Management Service. For offshore operations, lessees must obtain Minerals Management Service approval for exploration plans and development and production plans prior to the commencement of the operations. In addition to permits required from other agencies, such as the Coast Guard, the Army Corps of Engineers and the Environmental Protection Agency, lessees must obtain a permit from the Minerals Management Service prior to the commencement of drilling. In certain instances, substantial Certificates of Financial Responsibility or other acceptable assurances must be provided and maintained under the federal Oil Pollution Act of 1990.

The Minerals Management Service promulgates and enforces regulations that require offshore production facilities located on the Outer Continental Shelf to meet stringent engineering, construction, and safety specifications, that impose strong restrictions on the flaring or venting of natural gas, that prohibit the burning of liquid hydrocarbons and oil without prior authorization, and that govern the plugging and abandonment of offshore wells and removal of offshore production facilities. To cover the various obligations of lessees on the Outer Continental Shelf, the Minerals Management Service generally requires that lessees post and maintain substantial bonds or other acceptable assurances that these obligations will be met. The Outer Continental Shelf Lands Act may generally impose liabilities on us for our offshore operations conducted on federal leases for clean-up costs and damages caused by pollution resulting from our operations. Under circumstances such as conditions deemed to be a threat or harm to the environment, the Minerals Management Service may suspend or terminate any of our operations in the affected area.

Natural Gas Sales and Transportation. Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production. The Federal Energy Regulatory Commission, or FERC, has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Since 1978, various federal laws have been enacted which have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in first sales, which include all of our sales of our own production. FERC also regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC s initiatives have led to the development of a competitive, open access market for gas purchases and sales that permits all purchasers of gas to buy gas directly from third party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the current regulatory approach will continue in the future, nor can we determine what effect, if any, future regulatory changes might have on our natural gas related activities.

Under FERC s current regulatory regime, interstate transmission services must be provided on an open-access, non-discriminatory basis at cost-based rates, or at market-based rates if the transportation market is sufficiently competitive. In state waters and onshore, gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states. In offshore Federal waters, the Outer Continental Shelf Lands Act provides that every permit or other grant of authority for the transportation of oil or gas by pipeline on or across the Outer Continental Shelf must require the pipeline to provide open and nondiscriminatory access, but does not authorize FERC to create and enforce open access rules or to regulate rates for gathering on the Outer Continental Shelf. The lack of federal oversight over the rates charged for gathering on the Outer Continental Shelf affects our costs of getting the gas we produce on the Outer Continental Shelf to point-of-sale locations.

Environmental Matters and Regulation

General. Our operations are subject to and must comply with the same federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection as other companies in the oil and gas exploration and production industry. These laws and regulations may:

- require the acquisition of a permit before drilling commences;
- require the installation of expensive pollution control measures;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on lands lying within wilderness, wetlands and other protected areas;

- require remedial measures to prevent pollution from former operations, such as pit closure and plugging of abandoned wells; and

- impose substantial liabilities for pollution resulting from our operations.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and the federal and state agencies frequently revise the environmental laws and regulations. Any changes that result in more stringent and costly waste handling, disposal and

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clean-up requirements could have a significant impact on the oil and gas industry s operating costs, including ours. We believe that we substantially comply with all current applicable environmental laws and regulations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. However, we cannot predict the passage of or quantify the potential impact of more stringent future laws and regulations at this time. For the year ended December 31, 2006, we did not incur any material capital expenditures for environmental control facilities. As of the date of this Annual Report, we are not aware of any environmental issues or claims that will require material expenditures during 2007 and 2008 or that will have a material impact on our financial position or results of operations.

The most significant of these environmental laws and regulations include, among others, the:

Resource Conservation and Recovery Act. The Resource Conservation and Recovery Act, or RCRA, affects oil and gas production activities by imposing regulations on the generation, transportation, treatment, storage, disposal and cleanup of hazardous wastes and on the disposal of non-hazardous wastes. Under the auspices of the Environmental Protection Agency, or the EPA, the individual states administer some or all of the provisions of the Resource Conservation and Recovery Act, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of crude oil, natural gas, or geothermal energy constitute solid wastes, which are regulated under the less stringent non-hazardous waste provisions, but there is no guarantee that the EPA or the individual states will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to recategorize certain oil and gas exploration and production wastes as hazardous wastes.

We believe that we are currently in substantial compliance with the requirements of the Resource Conservation and Recovery Act and related state and local laws and regulations and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under the Resource Conservation and Recovery Act.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the disposal site, or site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substance. CERCLA also authorizes the EPA and affected parties to respond to threats to the public health or the environment and to seek recovery from responsible classes of persons for the costs of the response actions.

In the course of our operations, we generate wastes that may fall within CERCLA s definition of hazardous substances. Therefore, governmental agencies or third parties may seek to hold us responsible under CERCLA for all or part of the costs to clean up sites at which such hazardous substances have been deposited. As of the date of our report, however, we have no knowledge of having been named by the EPA or alleged by any third party as being responsible for costs and liability associated with alleged releases of any hazardous substance at any superfund site.

Oil Pollution Act. The Oil Pollution Act imposes on responsible parties strict, joint and several, and potentially unlimited liability for removal costs and other damages caused by an oil spill covered by the Oil Pollution Act and offers few defenses to such liability. The Oil Pollution Act also requires the lessee of an offshore area or a permittee whose operations take place within a covered offshore facility to establish and maintain financial responsibility of at least $35 million, which may be increased to $150 million for facilities with large worst-case spill potentials and under other circumstances, to cover liabilities related to an oil spill for which the lessee or permittee of the offshore area is statutorily responsible. Owners of multiple facilities are required to maintain financial responsibility for only the facility with the largest potential worst-case spill. We have received certification from the Minerals Management Service that due to our financial status, we are able to cover a minimum of $35 million per occurrence and because we do not have major oil producing facilities, the maximum certification of $150 million in coverage is not currently required. As such, we currently believe we are in substantial compliance with the financial responsibility provisions of the Oil Pollution Act. If we completely divest our Gulf of Mexico assets, we would no longer be subject to the provisions of the Oil Pollution Act.

Federal Water Pollution Control Act/Clean Water Act. The Federal Water Pollution Control Act or Clean Water Act and related state laws provide varying civil and criminal penalties and liabilities for the unauthorized discharge of petroleum products and other pollutants to surface waters. The federal discharge permitting program also prohibits the discharge of produced water, sand and other substances related to the oil and gas industry to coastal waters. Regulations governing water discharges also impose other requirements, such as the obligation to prepare spill response plans. We currently

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believe that we are in substantial compliance with all pollutant, wastewater, and stormwater discharge regulations and that we hold all necessary and valid permits, other required authorizations, and spill response plans for the discharge of such materials from our operations.

Federal Clean Air Act. The Federal Clean Air Act restricts the emission of air pollutants and affects both onshore and offshore oil and gas operations. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to incur capital costs in order to remain in compliance. In addition, EPA has developed and continues to develop more stringent regulations governing emissions of toxic air pollutants. These regulations may increase the costs of compliance for some facilities. We currently believe that we are in substantial compliance with all air emissions regulations and that we hold all necessary and valid construction and operating permits for our operations.

In 1997, numerous countries participated in an international conference under the United Nations Framework Convention on Climate Change and concluded an agreement, known as the Kyoto Protocol. The Protocol became effective February 14, 2005, and will require reductions of certain emissions that contribute to atmospheric levels of greenhouse gases. The United States has not ratified the Protocol but may in the future. Presently, it is not possible to accurately estimate the costs we could incur to comply with any laws or regulations developed to achieve such emissions reductions, but such expenditures could be substantial.

Legislation continues to be introduced in Congress and development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including oil and gas facilities. Our operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the costs we could incur to comply with any such facility security laws or regulations, but such expenditures could be substantial.

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Item 1A. Risk Factors

We are subject to significant business uncertainties and contractual restrictions while our merger with Forest Oil Corporation is pending.

Uncertainty about the effect of the proposed merger with Forest Oil Corporation on employees, suppliers and partners may have an adverse effect on us and our business. These uncertainties may impair our ability to attract, retain and motivate key personnel until the merger is consummated, and could cause persons that deal with us to defer decisions concerning their business relationship with us, or to seek to change their existing business relationships with us. Employee retention may be particularly challenging while the merger is pending, as employees may experience uncertainty about their future employment. In addition, the merger agreement significantly restricts our business operations while the merger is pending, including our ability to make capital expenditures, pursue acquisitions, borrow money other than in the ordinary course of our business, enter into hedging arrangements and take other specified actions without Forest s approval. These restrictions could prevent or delay us from pursuing attractive business or market opportunities that may arise prior to the completion of the merger.

The failure to complete the merger could negatively impact our stock price, future business and financial results.

Although the board of directors has unanimously recommended that our stockholders adopt and approve the merger agreement, and Forest s board of directors has unanimously recommended that its shareholders approve the issuance of additional shares of Forest common stock in the merger, we cannot assure you that the merger and the merger agreement will be approved by our stockholders or that the issuance of additional shares of Forest common stock in the merger will be approved by Forest s shareholders, or that other conditions to the completion of the merger will be satisfied. If the merger is not completed, we will be subject to numerous risks, including the following:

§ We may be required to pay a termination fee of $55 million if the merger agreement is terminated under certain circumstances and we enter into an alternative transaction;

§ The current market price of our common stock may reflect a market assumption that the merger will occur, and a failure to complete the merger could result in a decline in the market price of our common stock;

§ We are obligated to pay certain costs relating to the merger (such as legal and financial advisory fees) whether or not the merger is completed, and we may be required to pay a $5 million fee to Forest to cover its expenses if the merger is not consummated for certain reasons;

§ There may be substantial disruption to our business and our management and employees have been and will continue to be distracted from day-to-day operations because matters related to the merger (including integration planning) require substantial commitments of time and resources, which could otherwise have been devoted to other activities and business opportunities that could have been beneficial to us and our stockholders;

Our business could be adversely affected if we are unable to retain key employees or attract qualified replacements; and

§ We would continue to face the risks that we currently face as an independent company.

We are subject to an ongoing shareholder lawsuit, which could result in an injunction preventing consummation of the merger or significant monetary damages.

Houston Exploration s directors and Forest are defendants in a shareholder lawsuit brought in Houston, Texas by the City of Monroe Employees Retirement System. The plaintiff asserts, on behalf of an uncertified class of our stockholders, that the Houston Exploration directors breached their fiduciary duties by not pursing an unsolicited proposal made on June 12, 2006 by JANA Partners LLP to purchase the outstanding shares of Houston Exploration common stock for $62 per share. The plaintiff also seeks to enjoin the merger, asserting that our directors decision to enter into the merger with Forest constitutes a breach of fiduciary duties, because, the plaintiff alleges, the merger consideration is inadequate. This lawsuit is at an early stage and subject to substantial uncertainties concerning the outcome of material factual and legal issues. Accordingly, based on the current status of the litigation, we cannot currently predict the manner and timing of the resolution of the lawsuit, the likelihood of the issuance of an injunction preventing the consummation of the merger, or an estimate of a range of possible losses or any minimum loss that could result in the event of an adverse verdict in the lawsuit. Although our insurance policies should provide coverage for the claims against our directors, the policies may not be sufficient to cover all costs and liabilities associated with the lawsuit. We believe this lawsuit is without merit, and we intend to vigorously defend against it. Although it is too soon to predict the outcome of this lawsuit or the time to resolution, we do not believe that it will have a material adverse effect on our financial position, results of operations or cash flows.

The volatility of natural gas and oil prices may affect our financial results.

As an independent natural gas and oil producer, our revenues, operating results, profitability and future rate of growth are highly dependent on the price of, and demand for, the natural gas and oil that we sell. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. Even relatively modest changes in natural gas and oil prices may significantly change our revenues, results of operations, cash flows and proved reserves.

Historically, the markets for natural gas and oil have been volatile and are likely to continue to be volatile in the future. Prices for natural gas and oil may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control, such as:

§ weather conditions;

§ the price of foreign imports;

§ overall domestic and global economic conditions;

§ terrorist attacks or military conflicts;

§ political conditions, economic stability, and armed conflicts in oil producing regions;

§ the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;

§ the level of consumer demand and the price and availability of alternative fuels;

§ speculation in the commodity futures markets;

§ technological advances affecting energy consumption;

§ domestic and foreign governmental regulations, including regulations imposed by Native American tribes; and

§ approvals, proximity and capacity of natural gas and oil pipelines and other transportation facilities.

These factors and the volatility of the energy markets make it extremely difficult to predict future natural gas and oil price movements with any certainty. Declines in natural gas and oil prices would not only reduce our revenues, but could reduce the amount of natural gas and oil we can economically produce. 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. Further, market prices for natural gas and oil do not necessarily move in direct relationship to each other. We are more affected by movements in the price and demand for natural gas, as approximately 96% of our total proved reserves at December 31, 2006 were natural gas.

Our ability to replace revenues generated from the sale of substantially all of our Gulf of Mexico properties depends upon market conditions, restrictions under the pending merger agreement and numerous uncertainties.

During 2006, we completed the sale of substantially all of our Gulf of Mexico assets. Although we may reinvest the proceeds from the sale of our Gulf of Mexico assets in onshore producing assets, we cannot assure you that we will be able to find suitable properties on attractive terms or that, if found, we would be permitted under the merger agreement to acquire such properties. Our operating revenues and cash flows decreased significantly following the sale of these assets and are expected to remain at lower levels until we are able to replace the lost production with production from new properties. The merger agreement significantly restricts our business operations while the merger is pending, including our ability to make capital expenditures, pursue acquisitions, borrow money other than in the ordinary course of business, enter into hedging arrangements and take other specified actions without Forest s approval. These restrictions could prevent us from pursuing attractive business or market opportunities that may arise prior to completion of the merger.

A significant increase in our level of indebtedness may limit our financial flexibility.

As of December 31, 2006, we had long-term indebtedness of $175 million, all of which was our 7% senior subordinated notes, as we had no outstanding borrowings under our bank credit facility. Our long-term indebtedness represented 15.2% of our total book capitalization at December 31, 2006. As of the date of this Annual Report, we had no outstanding borrowings under our bank credit facility.

Our level of indebtedness affects our operations in several ways, including the following:

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- § a portion of our cash flows from operating activities must be used to service our debt and is therefore not available for other purposes;
- § we may be at a competitive disadvantage as compared to similar companies that have less debt;
- § the covenants contained in the agreements governing our outstanding debt require us to meet certain financial tests and may limit our ability to borrow additional funds, sell assets, repurchase shares of company stock, pay dividends and make certain investments and may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- § we may not be able to easily divest or exchange our assets because they have been mortgaged to secure borrowings under our revolving bank credit facility;
- § any additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes may have higher costs and more restrictive covenants; and
- § changes in the credit ratings of our debt may negatively affect the cost, terms, conditions and availability of future financing.

Subject to the restrictions in the merger agreement, we may incur additional debt in order to make future acquisitions or develop our properties. A higher level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt service obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, commodity prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flow to pay the interest on our debt, and future working capital, borrowings or equity financing may not be available to pay or refinance such debt. Factors that would affect our ability to raise cash through an offering of our stock or a refinancing of our debt include financial market conditions, the value of our assets and our historical and expected future financial performance.

We may be required to take significant writedowns if natural gas and oil prices decline.

We may be required under full cost accounting rules to write down the carrying value of our natural gas and oil properties if natural gas and oil prices decline or if we have substantial downward adjustments to our estimated proved reserves, capital expenditures that do not generate equivalent or greater value in proved reserves, increases in our estimated future operating, development or abandonment costs or deterioration in our exploration results.

We utilize the full cost method of accounting for natural gas and oil exploration and development activities. Under full cost accounting, we are required by SEC regulations to perform a ceiling test each quarter. The ceiling test is an impairment test and generally establishes a maximum, or ceiling, of the book value of our natural gas and oil properties that is equal to the expected after tax present value (discounted at 10%) of the future net cash flows from proved reserves, including the effect of cash flow hedges, if applicable, calculated using market prices in effect as of the balance sheet date, as adjusted for basis or location differentials and held constant over the life of the reserves (net wellhead prices). If the net book value of our natural gas and oil properties (reduced by any related net deferred income tax liability and asset retirement obligation) exceeds our ceiling limitation, SEC regulations require us to impair or write down the book value of our natural gas and oil properties. Depending on the magnitude of any future impairments, a ceiling test writedown could significantly reduce our income, or produce a loss. A ceiling test writedown would not impact cash flow from operating activities, but it would reduce shareholders equity. The risk of a required ceiling test writedown of the book value of natural gas and oil properties increases when natural gas and oil prices are low or volatile. As ceiling test computations involve the prevailing price on the last day of the quarter, it is impossible to predict the timing and magnitude of any future impairments.

In calculating our ceiling test at December 31, 2006, we estimated that, using an average net wellhead price of $4.94 per Mcf, the carrying value of our full cost pool exceeded the ceiling limitation by approximately $582.8 million ($376.5 million net of tax). However, since December 31, 2006, the market price for natural gas increased such that, using an average net wellhead price of $6.63 per Mcf on February 20, 2007, a writedown of $19.0 million ($12.3 million net of tax) in the carrying value of our natural gas and oil assets was required. As a result, and pursuant to full cost accounting rules, we recorded a non-cash charge and reduction to earnings in the fourth quarter of 2006.

Lower natural gas and oil prices could negatively impact our ability to borrow.

The amount of borrowings available to us under our bank credit facility is determined by reference to a borrowing base. The amount of our borrowing base is established by our banks and is primarily a function of the quantity and value of our reserves. Our borrowing base is re-determined at least twice a year to take into account changes in our reserve base and prevailing commodity prices. Our current borrowing base is $500 million which is expected to remain in effect until the next scheduled redetermination on April 1, 2007. Commodity prices can affect both the value as well as the quantity of our reserves for borrowing base purposes, as certain reserves may not be economic at lower price levels. Additionally, the indenture governing our 7% senior subordinated notes due 2013 conditions our ability to incur additional indebtedness on our satisfaction of tests relating to earnings before interest, taxes and depreciation, depletion and amortization expense and consolidated net tangible assets (as defined in the indenture), both of which are sensitive to commodity prices. Consequently, the amount of borrowing available to us under our bank credit facility, as well as our ability to incur additional indebtedness without violating the indenture governing our senior subordinated notes, could be adversely affected by extended periods of low commodity prices.

Our hedging activities have resulted in significant financial losses and may continue to do so in the future.

In an effort to achieve more predictable cash flow and to reduce our exposure to downward fluctuations in the prices of natural gas, we have historically entered into derivative contracts covering a significant portion of our production. During 2006, 2005 and 2004, we incurred losses from hedging activities of $64.5 million, $264.5 million and $70.1 million, respectively. These losses included realized losses on contracts settled during the each of the respective periods of $69.2 million ($44.2 million net of tax), $265.2 million ($171.3 million net of tax) and $68.2 million ($44.1 million, net of tax). As of the date of this Annual Report, we have approximately 41% of our estimated 2007 production hedged and approximately 42% of our estimated 2008 production hedged during the months of January and February, with contracts covering approximately 8% of estimated production during the remaining 10 months of 2008.

By the end of the first quarter of 2006, all of our open derivative contracts ceased to qualify for hedge accounting. As a result, our earnings after that date became more volatile, as mark-to-market accounting was required, and all subsequent changes in the fair market value of open contracts have been and will be recognized as an increase or reduction to natural gas and oil revenues. At December 31, 2006, an unrealized loss of $18.5 million, net of tax, remains deferred in accumulated other comprehensive income relating to prior hedge accounting. This loss represents the fixed value of our remaining open derivative contracts deferred in accumulated other comprehensive income at the time they ceased to qualify for hedge accounting. All remaining deferred losses will be reclassified and recognized in future earnings at the time when sale of the related forecasted natural gas production occurs. Over the next 12-month period, we expect to reclassify from accumulated other comprehensive income to earnings a loss of $11.1 million, net of tax, with $7.4 million to be recognized thereafter.

The high-rate production characteristics of our properties subject us to high reserve replacement needs and require significant capital expenditures to replace our reserves at a faster rate than companies whose reserves have longer-life production profiles.

Our proved reserve quantities decline as they are produced. To prevent decline in our reserve base, we must conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves. Producing natural gas and oil reservoirs are generally characterized by declining production rates that vary depending on reservoir characteristics and other factors. Virtually all of our onshore production is located in prolific natural gas producing regions where completion techniques result in hyperbolic production decline profiles characterized by high initial production rates, followed by rapid intermediate production declines, and culminating in a long-term low production rate subject to a shallow decline. Because of the high-rate production profiles of our properties, replacing produced reserves is more important for us than for companies whose reserves have longer-life production profiles. This imposes greater reinvestment risk for our company as we may not be able to continue to replace our reserves or may not be able to do so at an acceptable finding cost.

Rising finding and development costs may impair our profitability.

In order to continue to grow and to maintain our profitability, we must annually add new reserves exceeding our yearly production at a finding and development cost that yields an acceptable operating margin and depreciation, depletion and amortization rate. Without cost effective exploration, development or acquisition activities, our production, reserves and profitability will decline over time. Given the relative maturity of most gas basins in North America, combined with an overall increase in the demand for domestic production, the cost of finding new reserves through exploration and development operations has been increasing. During the last three-year period, commodity prices have remained higher than historical levels, resulting in higher costs for materials, equipment and services. The acquisition market for natural gas properties has become extremely competitive among producers for additional production and expanded drilling opportunities in North America. Acquisition values on a per unit basis are at or near record levels in certain of our focus areas, particularly South Texas, the Rocky Mountain regions and East Texas, and we believe these values may continue to increase in 2007. For full cost companies such as ours, this increase in finding and development costs results in higher depreciation, depletion and amortization rates. If finding and development costs continue to increase, we and other full cost companies will be exposed to an increased likelihood of a writedown in carrying value of our natural gas and oil properties, especially if prices do not increase accordingly, which would impair our profitability. During the fourth quarter of 2006, we

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incurred a writedown in the carrying value of our natural gas and oil properties of $19.0 million ($12.3 million net of tax), due in part to the cumulative effect of higher finding and development costs in recent years.

The success of our business depends upon our ability to find, replace, develop and acquire natural gas and oil reserves.

Without successful exploration, development or acquisition activities, our oil and gas reserves and our revenues will decline over time. In addition, we may not be able to maintain our current cost structure while continuing to operate in mature producing basins. It is becoming more difficult to find, replace and develop new reserves at historical costs. The continuing development of reserves and acquisition activities require significant expenditures. Our cash flow from operations may not be sufficient for this purpose, and we may not be able to obtain the necessary funds from other sources. In addition, as discussed above, if we are not able to replace reserves, the amount of credit available to us may decrease since the amount of borrowing capacity available under our bank credit facility is based, in large part, on the estimated quantities of our proved reserves.

Estimates of proved reserves and future net revenue may change if the assumptions on which such estimates are based prove to be inaccurate.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment and the assumptions used regarding prices for oil and natural gas, production volumes, required levels of operating and capital expenditures, and quantities of recoverable natural gas and oil reserves. Natural gas and oil prices have fluctuated widely in recent years. Volatility is expected to continue, and price fluctuations directly affect estimated quantities of proved reserves and future net revenues. Actual prices, production, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from those assumed in our estimates, and these variances may be significant. Also, we make certain assumptions regarding future natural gas and oil prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from the assumptions used could result in the actual quantity of our reserves and future net cash flow being materially different from the estimates in our reserve reports. In addition, actual results of drilling, testing and production and changes in natural gas and oil prices after the date of the estimate may result in revisions to our reserve estimates. Revisions to prior estimates may be material. During 2006, 2005 and 2004, we incurred downward revisions of our proved reserves of 31 Bcfe, 60 Bcfe and 20 Bcfe, respectively, either from proved undeveloped reserves that were determined to be depleted or otherwise not recoverable, reserves that were uneconomical due to prices at the end of the applicable period, or production performance indicating less gas in place or smaller reservoir size than initially estimated. We cannot assure you that we will not face similar downward revisions in the future.

We may not be able to meet our substantial capital requirements.

Our business is capital intensive. To maintain or increase our base of proved oil and gas reserves, we must invest a significant amount of cash flow from operations in property acquisitions, development and exploration activities. We are currently making and will continue to make substantial capital expenditures to find, develop, acquire and produce natural gas and oil reserves. If our revenues or borrowing base under our revolving bank credit facility decrease as a result of lower natural gas and oil prices, operating difficulties or declines in reserves, we may not be able to expend the capital necessary to undertake or complete future drilling programs or acquisition opportunities unless we raise additional funds through debt or equity financings. We may not be able to obtain such debt or equity financings, and cash generated by operations or available under our revolving bank credit facility may not be sufficient to meet our capital requirements.

Our business involves many operating risks that can cause substantial losses; insurance may not protect us against all these risks.

In our operations we may experience hazards and risks inherent in drilling for, producing and transporting natural gas and oil. These hazards and risks may result in loss of hydrocarbons, environmental pollution, personal injury claims, and other damage to our properties and third parties and include:

§ fires;

§ natural disasters, including tropical storms, hurricanes and other adverse weather conditions;

§ explosions;

§ encountering formations with abnormal pressures;

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- § encountering unusual or unexpected geological formations;
- § blowouts;
- § cratering;
- § unexpected operational events;
- § equipment malfunctions;
- § pipeline ruptures;
- § spills;
- § compliance with environmental and government regulations; and
- § title problems.

We are insured against some, but not all, of the hazards associated with our business. Because of this practice, we may sustain losses that could be substantial due to events that are not insured or are underinsured. The occurrence of an event that is not covered or not fully covered by insurance could have a material adverse impact on our financial condition and results of operations. In addition, because we do not carry business interruption insurance, the loss and delay of revenues resulting from curtailed production are not insured.

Our reserves, production and cash flow are highly dependent upon operations that are concentrated in a small number of areas.

During 2006, and subsequent to the sale of substantially all of our Gulf of Mexico assets, we generated over 99% of our onshore production from four primary areas of operation. The concentrated nature of our operations subjects us to the risk that a regional event could cause a significant interruption in our production or otherwise have a material affect on our profitability. This is particularly true of operations along the Texas Gulf Coast, which are susceptible to hurricanes and other tropical weather disturbances, some of which can be severe enough to cause substantial damage to facilities and production infrastructure.

Drilling natural gas and oil wells is a high risk activity and subjects us to a variety of factors that we cannot control.

Our drilling activities subject us to many risks, including the risk that we will not find commercially productive reservoirs. Drilling for natural gas and oil can be unprofitable, not only from dry wells, but also from productive wells that do not produce sufficient revenues to return a profit. Also, title problems, weather conditions, governmental requirements and shortages or delays in the delivery of equipment and services can delay our drilling operations or result in their cancellation. The cost of drilling, completing and operating wells is often uncertain, and new wells may not be productive. As a result, we may not recover all or any portion of our investment.

The availability and cost of rigs, equipment, and personnel could adversely affect our profitability and level of operations.

Driven by attractive commodity prices, domestic drilling activity measured as a function of rig utilization has been at very high levels during the past three-year period. Given this extended strong demand for drilling rigs and other oil field services necessary to our operation, we experienced increased service and material costs, as well as longer lead times and reduced service availability. We anticipate that this trend will continue as long as commodity prices remain at attractive levels. If current utilization rates continue at levels seen during 2006 or increase, a general shortage of drilling and completion rigs, field equipment and qualified personnel could develop, especially in the areas where we operate. The costs and delivery times of rigs, equipment and personnel could be substantially greater than in previous years. If we do not have access to necessary oil field services at a reasonable cost, we could be forced to curtail certain operations and the profitability of those operations that we do conduct could be materially impaired.

Our business depends on oil and natural gas transportation facilities that are owned by others.

The marketability of our natural gas and oil production depends, in part, on the availability, proximity and capacity of pipeline systems owned by third parties. The lack of available capacity on these systems and related facilities could result in the shut-in of our producing wells or the delay or discontinuation of development plans for our properties. Although we have some control over the transportation of our product, material changes in these business relationships could materially affect our operations. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

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Any acquisition and investment activities may be unsuccessful and costly.

The successful acquisition of producing properties requires assessment of reserves, future commodity prices, operating costs and potential environmental and other liabilities. These assessments may not be accurate. Our review of the properties we intend to acquire may not reveal all existing or potential problems nor allow us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We may not always perform inspections on every property or well, and structural or environmental problems may not be observable even when an inspection is undertaken. Accordingly, we may suffer the loss of one or more acquired properties due to title deficiencies or may be required to make significant expenditures to cure environmental contamination or other problems with respect to acquired properties. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We are generally not entitled to contractual indemnification for environmental liabilities, and we typically acquire structures on a property on an as is basis.

We could lose certain leasehold rights if we do not drill all the wells that are necessary to hold our acreage, especially in the Rocky Mountains, before the initial lease terms expire.

Our future growth plans rely in part on establishing significant production and reserves in the Rocky Mountains, which as of December 31, 2006, represented approximately 10% of our total proved reserves. At December 31, 2006, approximately 96% of our total onshore undeveloped acreage is located in the Rockies, of which 45% will expire within the next three-year period. We also have undeveloped acreage offshore Louisiana. We may have difficulty drilling all of the wells that are necessary to hold this acreage before the initial lease terms expire, which could result in the loss of certain leasehold rights.

We may incur substantial costs to comply with costly and stringent environmental and other governmental laws and regulations.

Our exploration and production operations are regulated extensively at the federal, state, and local levels. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial obligations, and/or the issuance of injunctions limiting or prohibiting our operations. However, environmental laws and regulations, including those that may at some time arise to address global climate change or facility security concerns, are expected to continue to have an increasingly costly and stringent impact on our operations resulting in substantial costs and liabilities in the future.

We currently own and lease, and have in the past owned or leased, numerous properties that have been used for the exploration and production of oil and natural gas for many years. Although we believe we have used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where such wastes have been taken for disposal. In addition, petroleum hydrocarbons or wastes may have been disposed of or released by prior operators of properties that we have acquired or may acquire in the future as well as by current third party operators of properties in which we have an ownership interest. Properties impacted by any such disposals or releases could be subject to costly and stringent investigatory or remedial requirements under environmental laws, some of which impose strict, joint and several liability without regard to fault or the legality of the original conduct, including the federal Comprehensive Environmental Response, Compensation and Liability Act, the federal Oil Pollution Act, the federal Resource Conservation and Recovery Act and analogous state laws. Under such laws and any implementing regulations, we could be required to remediate contaminated properties and take actions to compensate for damages to natural resources. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury or property damages allegedly caused by the release of petroleum hydrocarbons or wastes into the environment.

We face strong competition.

As an independent natural gas and oil producer, we face strong competition in all aspects of our business. Competition is particularly intense for prospective undeveloped leases and purchases of proved oil and gas reserves. There is also competition for the rigs and related equipment and services that are necessary for us to develop and operate our natural gas and oil properties. Our competitive position is also highly dependent on our ability to recruit and retain geological, geophysical and engineering expertise. We compete for prospects, proved reserves, field services and qualified oil and gas professionals with major and diversified energy companies and other independent operators that have financial, human and technological resources greater than ours. These companies may be able to pay more for productive natural gas and oil properties and exploratory prospects and to more successfully define, evaluate, bid for and purchase properties and prospects than our financial and human resources permit. In addition, our competitors may have an advantage due to their geographic focus and their mix of oil and natural gas reserves.

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The inability of one or more of our customers to meet its obligations may adversely affect our financial results.
Substantially all of our accounts receivable result from natural gas and oil sales or joint interest billings to third parties in the energy industry. This concentration of customers and joint interest owners within a single industry may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties (see Item 1. Business and Properties)

Item 3. Legal Proceedings

See Consolidated Financial Statements, Note 9 Commitments and Contingencies *Legal Proceedings*, incorporated herein by reference, for a discussion of the material legal proceedings to which were are a party.

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

No matters were submitted to a vote of our security holders during the last quarter of the fiscal year ended December 31, 2006.

Part II.

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

Our common stock is traded on the New York Stock Exchange under the symbol THX. The following table sets forth the range of high and low intraday sales prices for each calendar quarterly period from January 1, 2005, through December 31, 2006 as reported on the New York Stock Exchange:

Year Ended December 31, 2006	**High**	**Low**
First Quarter	$62.56	$48.13
Second Quarter	62.50	49.75
Third Quarter	66.21	54.36
Fourth Quarter	57.75	51.60

Year Ended December 31, 2005	**High**	**Low**
First Quarter	$62.29	$51.14
Second Quarter	59.40	45.60
Third Quarter	71.47	53.30
Fourth Quarter	67.83	49.86

As of February 28, 2007, 28,155,996 shares of common stock were outstanding, and we had approximately 64 stockholders of record and approximately 8,250 beneficial owners.

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The following Corporate Performance Graph and related information shall not be deemed soliciting material or to be filed with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act or the Exchange Act, except to the extent that we specifically incorporate it by reference into such filing. The performance graph compares the performance of our common stock to the S&P 500 Index and to a peer group established by the Compensation Committee of our Board of Directors. This peer group is comprised of ten other independent oil and gas exploration and production companies with a similar mix of operations and includes Cabot Oil & Gas Corp., Cimarex Energy Company, Forest Oil Corporation, Newfield Exploration Company, Noble Energy Inc., Plains Exploration & Production Company, Pogo Producing Company, Southwest Energy Company, Stone Energy Corp., and XTO Energy Inc. The graph below matches the cumulative five-year total return of holders of our common stock with the cumulative total returns of the S&P 500 Index, and our peer group. The graph assumes that the value of the investment in our common stock and each index (including reinvestment of dividends) was $100 at December 31, 2001 and tracks the return on the investment through December 31, 2006.

Comparison of Five Year Cumulative Total Return* Among
The Houston Exploration Company, the S&P 500 Index and our Peer Group

Assumes $100 invested on December 31, 2001 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.

	December 31,					
	2001	**2002**	**2003**	**2004**	**2005**	**2006**
The Houston Exploration Company	$100.00	$ 91.13	$108.76	$167.69	$157.24	$154.20
S&P 500	$100.00	$ 77.90	$100.24	$111.15	$116.61	$135.03
Peer Group	$100.00	$114.49	$152.85	$210.69	$325.88	$348.57

Dividends

We have not declared or paid any cash dividends and do not anticipate declaring any dividends in the foreseeable future. We plan to retain our cash for the operation and expansion of our business, including exploration, development and acquisition activities. In addition, our bank credit facility, the indenture governing our 7% senior subordinated notes due June 15, 2013, and our merger agreement with Forest all contain restrictions on the payment of dividends to holders of common stock. For more information, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and Consolidated Financial Statements, Note 2 Long-Term Debt and Notes and Note 3 Stockholders Equity *Stockholder Rights Plan.*

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Item 6. Selected Financial Data

The following table shows selected financial data derived from our consolidated financial statements for each of the five years in the period ended December 31, 2006. You should read these financial data in conjunction with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and our Consolidated Financial Statements and the related Notes.

	Years Ended December 31,				
	2006	**2005**	**2004**	**2003**	**2002**
	(in thousands, except per share data and ratios)				
Income Statement Data:					
Revenues:					
Natural gas and oil revenues	$ 529,586	$ 620,271	$ 649,087	$ 491,440	$ 344,295
Other	2,011	1,272	1,352	1,312	1,086
Total revenues	531,597	621,543	650,439	492,752	345,381
Expenses:					
Lease operating expense	63,959	67,796	55,925	47,072	33,976
Severance tax	18,102	18,121	11,933	15,958	9,487
Transportation expense	10,636	11,883	11,819	10,387	9,317
Asset retirement accretion expense(1)	3,373	5,278	4,902	3,668	
Depreciation, depletion and amortization	253,666	295,351	265,148	197,530	171,610
Writedown in carrying value	19,000				
General and administrative, net	36,013	38,378	32,899	19,542	13,077
Total operating expenses	404,749	436,807	382,626	294,157	237,467
Income from operations	126,848	184,736	267,813	198,595	107,914
Other (income) expense(2)	(13,495)	142	(1,058)	(15,746)	(9,070)
Interest expense, net	25,206	16,535	9,455	8,342	7,398
Income before income taxes	115,137	168,059	259,416	205,999	109,586
Income tax provision	47,354	62,890	96,592	72,187	39,092
Income before cumulative effect of change in accounting principle	$ 67,783	$ 105,169	$ 162,824	$ 133,812	$ 70,494
Cumulative effect of change in accounting principle(3)				(2,772)	
Net income	$ 67,783	$ 105,169	$ 162,824	$ 131,040	$ 70,494
Earnings per share:					
Basic:					
Income per share before cumulative effect of change in accounting principle change	$ 2.37	$ 3.66	$ 5.50	$ 4.30	$ 2.31

Cumulative effect of change in accounting principle(3)				(0.09)	
Net income per share basic	$ 2.37	$ 3.66	$ 5.50	$ 4.21	$ 2.31
Diluted:					
Income per share before cumulative effect of change in accounting principle	$ 2.36	$ 3.62	$ 5.44	$ 4.29	$ 2.28
Cumulative effect of change in accounting principle(3)				(0.09)	
Net income per share diluted	$ 2.36	$ 3.62	$ 5.44	$ 4.20	$ 2.28
Weighted average shares basic	28,543	28,707	29,616	31,097	30,569
Weighted average shares diluted	28,693	29,037	29,932	31,213	30,878
Ratio of earnings to fixed charges(4)	4.7x	7.2x	15.0x	13.6x	7.6x

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	Years Ended December 31, 2006	2005	2004	2003	2002
	(in thousands)				
Cash Flow Data:					
Net cash provided by operating activities	$ 416,189	$ 460,509	$ 527,141	$ 381,969	$ 243,601
Net cash provided by (used) in investing activities[5]	105,007	(727,003)	(509,922)	(452,959)	(252,857)
Net cash provided by (used in) financing activities[6]	(475,225)	255,896	(1,211)	55,528	17,668

	At December 31, 2006	2005	2004	2003	2002
	(in thousands)				
Balance Sheet Data:					
Working capital (deficit)[7]	$ 247	$ (214,525)	$ (31,884)	$ (36)	$ 10,550
Property, plant and equipment, net[8]	1,591,332	2,018,340	1,548,256	1,371,129	1,022,414
Total assets[8]	1,771,726	2,361,624	1,722,577	1,509,065	1,151,068
Long-term debt and notes[9]	175,000	597,000	355,000	302,000	252,000
Stockholders equity	964,604	693,138	782,920	735,534	592,789

(1) Subsequent to the adoption of SFAS 143, Accounting for Asset Retirement Obligations, we have recognized accretion expense as the estimated future obligations that we have recorded accrete to fair value.

(2) For 2006, Other (income) expense of $13.5 million in net other income was comprised of (i) $8.7 million of interest income earned on cash proceeds from the sale of substantially all of

our Gulf of Mexico assets during the first and second quarters of 2006, (ii) income of $7.7 million of refunds of prior years severance tax expense that were recognized pursuant to the receipt of a high cost/tight sand designation for a portion of our South Texas production in July 2002; and (iii) $2.9 million of expense relating to prior period offshore transportation expense that was billed during 2006. See Consolidated Financial Statements, Note 9 Commitments and Contingencies.

For 2005, Other (income) expense of $0.1 million in net other expenses was comprised of (i) income of $2.7 million recognized for refunds of prior years severance tax expense and (ii) expense of $2.8 million incurred as a result of a payout settlement at East Cameron 82/83 during the first quarter of 2005, whereby our working interest in the A3 well was subsequently reduced from 50% to 35%.

For 2004, Other (income) expense of $1.0 million in net other income comprised of (i) income of $1.2 million recognized for refunds of prior years severance tax expense and (ii) $0.2 million in debt extinguishment expenses incurred during the second quarter of 2004 pursuant to the reduction of our borrowing base from $375 million to $340 million as a result of the disposition of our Appalachian Basin assets.

For 2003, Other (income) expense of $15.5 million in net other income is comprised of (i) income of $21.6 million recognized for refunds of prior years severance tax expense and (ii) $5.9 million in expenses incurred pursuant to the early redemption of our $100 million $8^{5}/_{8}$ % notes in June 2003.

For 2002, Other (income) expense is comprised of income of $9.1 million recognized for refunds of prior years severance tax expense.

(3) On January 1, 2003, we adopted SFAS 143, Accounting for Asset Retirement Obligations, which addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. Pursuant to our adoption of SFAS 143, we recognized a charge to income during the first quarter of 2003 of $2.8 million, net of tax, for the cumulative effect of the change in accounting principle. See Consolidated Financial Statements, Note 1 Summary of Organization and Significant

Accounting Policies *Asset Retirement Obligations*.

(4) For purposes of determining the ratio of earnings to fixed charges, earnings are defined as income (loss) before tax plus fixed charges, adjusted to exclude capitalized interest. Fixed charges consist of interest expense, whether expensed or capitalized, and an imputed or estimated interest component of rent expense. See Exhibit 12.1 filed with this Annual Report for the calculation.

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(5) For 2006, net cash flows provided by investing activities includes net proceeds of $719.2 million primarily from dispositions during the year, including proceeds from the sale of substantially all of our Gulf of Mexico assets during the first half of 2006, net of cash used in the acquisition of property and equipment, of $614.2 million.

(6) For 2006, a portion of the proceeds from the sale of substantially all of our Gulf of Mexico assets was used to reduce borrowings under our bank credit facility by a net $422.0 million. In addition, we used $61.6 million in cash to repurchase and retire 1,776,500 shares of our common stock.

(7)

The small amount ($0.2 million) of positive working capital at December 31, 2006 and the working capital deficits at December 31, 2005, 2004 and 2003 were primarily caused by the fair value of our obligations under derivative contracts estimated to be payable during next 12-month period, offset in part by the associated deferred tax asset during each of these years.

(8) For 2006, reflects the sale of substantially all of our Gulf of Mexico assets.

(9) For 2006, a portion of the proceeds form the sale of our substantially all of our Gulf of Mexico assets was used to repay a net $422.0 million in outstanding borrowings under our bank credit facility.

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

The following discussion is intended to assist you in understanding our business and the results of operations together with our present financial condition. This section should be read in conjunction with our Consolidated Financial Statements and the accompanying notes included elsewhere in this Annual Report on Form 10-K.

Statements in our discussion may be forward-looking. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations. See Forward-Looking Statements at the beginning of this Annual Report and Item 1A. Risk Factors beginning on page 15 for additional discussion of some of these factors and risks.

Overview of Our Business

We are an independent natural gas and oil producer engaged in the exploration, development, exploitation and acquisition of natural gas and oil reserves in North America. We were founded in December 1985 as a Delaware corporation and wholly-owned subsidiary of our then parent company, KeySpan Corporation. We completed our initial public offering in September 1996. Through three separate transactions, the last of which occurred in November 2004, KeySpan completely divested of its ownership in the common stock of our company. As of December 31, 2006, our operations were concentrated in four producing regions within the United States: South Texas; the Arkoma Basin of Arkansas and Oklahoma; East Texas; and the Uinta and DJ Basins of the Rocky Mountains.

During the first half of 2006, we completed the sale of substantially all of our Gulf of Mexico assets. The sale of these offshore properties was part of our strategic plan announced in November 2005 to shift our operating focus primarily onshore. The sale of our Gulf of Mexico assets had a significant impact on our operating results for the year ended December 31, 2006 and on the comparability of those results year-over-year.

Our total net proved reserves as of December 31, 2006 were 699 Bcfe. All of our reserves are estimated on an annual basis by independent petroleum engineers. Approximately 67% of our proved reserves at December 31, 2006 were classified as proved developed. During 2006, we produced 88.2 Bcfe of natural gas equivalents. Production volumes during 2006 were significantly impacted by the sale of substantially all of our Gulf of Mexico assets during the first and second quarters of 2006 and continued curtailments of certain of these offshore fields prior to their sale, primarily as a result of infrastructure damage to third party pipelines and processing facilities caused by Hurricanes Katrina and Rita that hit the Louisiana and Texas coasts in August and September 2005.

We derive our revenues from the sale of natural gas and oil that is produced from our natural gas and oil properties. Revenues are a function of the volume produced and the prevailing market price at the time of sale. Because natural gas accounts for approximately 94% of our production, the price of natural gas is the primary factor affecting our revenues. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we have historically utilized derivative instruments to hedge future sales prices on a significant portion of our natural gas production. Our use of derivative instruments prevented us from realizing the full benefit of the strong natural gas price environment during 2006 and in each of the preceding three years, and may continue to do so in future periods. Our natural gas revenues may experience significant volatility in future periods as all of our open derivative contracts ceased to qualify for hedge accounting during the first quarter of 2006. In addition, all derivative contracts entered into subsequent to December 31, 2006 are expected to be accounted for using mark-to-market accounting. See Consolidated Financial Statements, Note 1 Summary of Organization and Significant Accounting Policies *Derivative Instruments and Hedging Activities*.

Segment reporting is not applicable for us, as all of our assets are based in North America, and each of our operating areas has similar economic characteristics and each meets the criteria for aggregation as defined in SFAS 131, Disclosures about Segments of an Enterprise and Related Information.

Strategic Restructuring Plan

In November 2005, we announced our strategic restructuring plan, the primary purpose of which was to enhance shareholder value by becoming a pure onshore operator.

During 2006, we completed significant steps toward our original restructuring objectives, including the sale of substantially all of our Gulf of Mexico assets for net cash proceeds of $721.6 million, as described in more detail below; the repurchase and retirement of 1,176,500 shares, or approximately 4% of our outstanding common stock, for approximately $61.6 million; and the liquidation and settlement of a portion of our open derivative contracts for natural gas for approximately $15.2 million.

On June 12, 2006, we received an unsolicited proposal from JANA Partners LLC, a hedge fund, to acquire our company for $62 per share, subject to due diligence and negotiation of required documentation. According to its public filings, JANA

Partners beneficially owned approximately 12.3% of our outstanding common stock as of the date of the proposal. On June 26, 2006, we announced our Board of Directors determination that the unsolicited proposal made by JANA Partners was not in the best interest of our shareholders and that Lehman Brothers Inc. had been engaged to assist us in exploring a broad range of strategic alternatives to further enhance shareholder value. In connection with our review of strategic alternatives, Lehman assisted our Board in soliciting third party indications of interest for proposed business combination transactions with Houston Exploration. During the solicitation and review period, forward natural gas prices declined significantly.

Pending Merger with Forest Oil Corporation

On January 7, 2007, we announced the conclusion to the strategic alternatives review process with our entry into an agreement and plan of merger with Forest Oil Corporation. Under the merger agreement, Forest will acquire all of the outstanding shares of Houston Exploration for a combination of cash and Forest common stock.

Under the terms of the merger agreement, our shareholders will receive total consideration equal to 0.84 shares of Forest common stock and $26.25 in cash for each outstanding share of Houston Exploration common stock, or an aggregate of an estimated 23.6 million shares of Forest common stock and cash of $740 million. Based on the closing price of Forest common stock on January 5, 2007, the last trading day prior to announcement of the transaction, this represents $52.47 per share of merger consideration to be received by Houston Exploration shareholders. The actual value of the merger consideration to be received by our shareholders will depend on the average closing price of Forest common stock for the ten trading days ending three calendar days prior to the effective date of the merger, and the amount of cash and stock consideration will be determined by shareholder elections, subject to proration and an equalization formula. It is anticipated that the stock portion of the consideration will be tax free to Houston Exploration shareholders.

The Boards of Directors of Houston Exploration and Forest each unanimously approved the proposed merger. The merger is subject customary terms and conditions, including the approval of both Houston Exploration and Forest shareholders, and is expected to be completed in the second quarter of 2007. Upon completion of the transaction, it is anticipated that Forest shareholders would own approximately 73% of the combined company, and Houston Exploration shareholders would own approximately 27%.

Concurrently with the execution of the merger agreement, funds affiliated with JANA Partners entered into a voting agreement with Forest pursuant to which the JANA funds agreed, during the term of the voting agreement, to vote their shares of our common stock in favor of the merger with Forest and the adoption of the merger agreement and against any transaction that would impede or delay the merger with Forest, and granted to Forest a proxy to vote their shares at any stockholder meeting convened to consider such matters. As of January 7, 2007, the JANA funds beneficially owned approximately 14.7% of our total issued and outstanding shares of our common stock. The voting agreement will terminate in certain instances, including an adverse recommendation change (as defined in the merger agreement) by our Board of Directors or any material amendment to the merger agreement that is adverse to us or our stockholders.

On February 8, 2007, Forest filed a registration statement on Form S-4 with the SEC, including a preliminary joint proxy statement / prospectus with respect to the merger. Also on February 8, 2007, the companies received notice of early termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvement Act with respect to the proposed transaction.

Disposition of Gulf of Mexico Assets

On March 31, 2006, we completed the sale of the Texas portion of our Gulf of Mexico assets. The $220 million gross sale price was initially adjusted by $29.2 million for various customary closing items, including the preliminary adjustment for operations related to the properties after January 1, 2006, the effective date of the transaction. Of the $190.8 million in net cash proceeds, approximately $140.1 million was received for assets sold to various partnerships affiliated with Merit Energy Company. In addition, approximately $43.1 million and $7.6 million were received from Hydro Gulf of Mexico, L.L.C. and Nippon Oil Exploration U.S.A. Ltd., respectively, pursuant to the exercise of their preferential purchase rights. We used $158 million of the net cash proceeds received from the sale of these assets to repay and reduce outstanding borrowings under our revolving credit facility; deposited in escrow $9.5 million of the proceeds with a qualified intermediary for potential reinvestment in like-kind exchange transactions under

Section 1031 of the Internal Revenue Code; and used substantially all of the $23.3 million balance for working capital purposes. During the third quarter of 2006, $7.6 million of funds escrowed in connection with the sale of the Texas portion of our offshore assets, representing that portion of the escrowed funds that had not been reinvested within the 180-day time period under Section 1031, was released from escrow and reclassified as cash. In accordance with full cost accounting, no book gain or loss was recognized on the sale. The net proceeds of $190.8 million were recorded as a reduction to the full cost pool.

On June 1, 2006, we completed the sale of substantially all of our Louisiana Gulf of Mexico assets for a gross sale price of $590 million. The sale of a substantial majority of these assets to various partnerships affiliated with Merit Energy

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Company was completed on May 31, 2006 pursuant to a purchase and sale agreement dated April 7, 2006, and the sale of certain working interests to Nippon Oil Exploration U.S.A. Ltd. and Chevron USA Inc. was completed on June 1, 2006 pursuant to the exercise of preferential purchase rights. The aggregate net cash proceeds received from the sale of these assets totaled approximately $530.8 million after customary initial closing adjustments, including the preliminary adjustment for operations related to the properties after January 1, 2006, the effective date of the transactions. Of the total net proceeds, approximately $510.2 million was received for assets acquired by the Merit affiliates, and approximately $16.6 million and $4.0 million was received from Nippon Oil Exploration U.S.A. Ltd. and Chevron USA Inc., respectively.

Of the $530.8 million in net cash proceeds received from the sale of the Louisiana portion of our Gulf of Mexico assets, $314.2 million was deposited in escrow directly with qualified intermediaries for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code, and substantially all of the $216.6 million balance, associated with properties sold outside the like-kind exchange arrangement,, was used to reduce outstanding borrowings under our revolving credit facility. In accordance with full cost accounting, no book gain or loss was recognized on the sale. The net proceeds of $530.8 million were recorded as a reduction to the full cost pool.

The sale of certain of our Gulf of Mexico properties accelerated the payment of a net profits interest to the predecessor owner of properties acquired by us in October 2003. On August 1, 2006, we paid approximately $21.0 million in connection with the net profits interest, which we funded with borrowings under our bank credit facility.

The sale transactions did not include 18 Louisiana offshore blocks, which we retained. Of these 18 blocks, four expired subsequent to the sales transactions, two were drilled during 2006, resulting in two successful exploratory wells, and 12 remain classified as undeveloped at the end of 2006.

In connection with the June 1, 2006 completion of the divestiture of substantially all our Gulf of Mexico assets, we were required under our bank credit facility to liquidate a portion of our 2006 derivative instruments. In order to comply with this requirement, in June 2006, we liquidated and settled open derivative contracts representing 60,000 MMBtu per day of hedged production for each of the months July through December 2006. The cost to liquidate and settle these contracts was approximately $14.3 million. In addition, on August 4, 2006, we liquidated and settled open derivative contracts representing 20,000 MMBtu per day of hedged production for each of the months September and October 2006. The cost to liquidate and settle these contracts was approximately $0.9 million.

On November 27, 2006, $314.1 million of previously escrowed funds relating to the sale of the Louisiana offshore assets, representing that portion of the escrowed funds that had not been reinvested within the 180-day period under Section 1031, was released from escrow and reclassified as cash. Upon release of the cash from escrow, we used $190 million to repay all outstanding borrowings under our bank credit facility and used the balance of approximately $124 million for working capital purposes. This included an estimated payment for federal income taxes for the fourth quarter of 2006 of $34.0 million, which estimated tax payment included the recognition of a taxable gain on the sale our Gulf of Mexico assets of approximately $264 million.

Acquisitions

On April 25, 2006, we completed the acquisition of certain interests in natural gas and oil producing properties and acreage in the Willow Springs Field of Gregg County, located in East Texas, from Samson Lone Star Limited Partnership. The $22 million cash purchase price was reduced to $21.3 million for various customary closing items, including an adjustment for operations related to the properties after the effective date of the transaction, January 1, 2006. The properties cover approximately 4,237 gross (3,579 net) acres, are adjacent to our existing operations in the Willow Springs Field and include interests in 28 producing wells with an average working interest of 80%. Based on internal estimates, total proved reserves associated with the interests acquired were 16.2 Bcfe as of January 1, 2006. The acquisition was funded with cash on hand of $19.1 million and borrowings under our revolving credit facility of $2.2 million.

On December 13, 2006, we acquired a 100% working interest in 10 producing wells in Webb County, Texas, from Legend Natural Gas II, LP. The $4.3 million purchase price was paid with cash on hand. The acquired properties cover approximately 3,000 acres and are located in close proximity to our producing assets in the South Laredo Field. Based on internal estimates, total proved reserves associated with the interests acquired were approximately 1.8 Bcfe.

On December 14, 2006, we completed the acquisition of certain interests in natural gas and oil producing properties, together with developed and undeveloped acreage, located along the Niobrara trend in the DJ Basin of Eastern Colorado and Western Nebraska, from Santos TOG Corp. (formerly known as Tipperary Oil & Gas Corporation). The net purchase price of $21.4 million was paid with cash on hand. The acquired properties and acreage cover approximately 145,000 net acres and include interests in approximately 305 wells. The majority of the interests acquired were incremental working interests ranging between 20% and 25% in wells operated by us. Based on internal estimates, total proved reserves associated with the interests acquired were approximately 14.2 Bcfe as of November 1, 2006, and daily production averaged 1 Mcfe per day, net to the interests acquired.

Critical Accounting Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make assumptions and prepare estimates that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities and revenues and expenses. We base our estimates on historical experience and various other assumptions that we believe are reasonable; however, actual results may differ. We evaluate our assumptions and estimates on a regular basis and discuss the development and disclosure process with our Audit Committee. See Consolidated Financial Statements, Note 1 Summary of Organization and Significant Accounting Policies for a discussion of our significant accounting policies.

Proved Reserves. All of our reserves are estimated on an annual basis by independent petroleum engineers. Our estimates of proved reserves are based on the quantities of natural gas and oil which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. However, 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 is very complex and relies on assumptions and subjective 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, engineering and geological interpretation, and judgment. In addition, as a result of volatility and changing market conditions, commodity prices and future development costs will change from period to period, causing estimates of proved reserves to change, as well as causing estimates of future net revenues to change. For the years ended December 31, 2006, 2005 and 2004, we revised our proved reserves downward from prior years reports by approximately 31 Bcfe, 60 Bcfe and 20 Bcfe, respectively, due to proved undeveloped reserves that were determined to be depleted or otherwise not recoverable, uneconomical due to market prices at the end of the applicable period, or from production performance indicating less gas in place or smaller reservoir size than initially estimated. Estimates of proved reserves are key components of our most significant financial estimates involving our rate for recording depreciation, depletion and amortization and our full cost ceiling limitation.

Unevaluated Properties. The balance of unevaluated properties is comprised of capital costs incurred for undeveloped acreage, wells and production facilities in progress and wells pending determination, together with capitalized interest costs for these projects. These costs are initially excluded from our amortization base until the outcome of the project has been determined, or generally, until it is known whether proved reserves will or will not be assigned to the property. We assess all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value. We assess our properties on an individual basis or as a group if properties are individually insignificant. Our assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization. We estimate that substantially all of our costs classified as unproved as of the balance sheet date will be evaluated and transferred within a four-year period.

Asset Retirement Obligations. Asset retirement obligations represent the estimated future abandonment costs of tangible long-lived assets such as platforms, wells, service assets, pipelines, and other facilities. We estimate the fair value of an asset s retirement obligation in the period in which the liability is incurred, if a reasonable estimate can be made. We employ a present value technique to estimate the fair value of an asset retirement obligation, which reflects certain assumptions, including an inflation rate, our credit-adjusted, risk-free interest rate, the estimated settlement date of the liability and the estimated current cost to settle the liability based on third party quotes and current actual costs. Changes in timing or to the original estimate of cash flows will result in changes to the carrying amount of the

liability.
Derivative Instruments.
To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we have historically utilized derivative instruments to hedge future sales prices on a significant portion of our natural gas production. Our derivative instruments are not held for trading purposes. Historically, all of our derivative contracts qualified for hedge accounting at inception of the contract and were designated as cash flow hedges. Under SFAS 133, the fair market value of open derivative contracts is reflected on the balance sheet as either an asset or liability. If derivative instruments qualify for

hedge accounting, changes in the fair value are deferred in accumulated other comprehensive income until the period the sale of the related production occurs. Under SFAS 133, we are required to assess the effectiveness of all our derivative contracts at inception and at least every three months. If open contracts cease to qualify for hedge accounting, as was the case during the first quarter of 2006, mark-to-market accounting is utilized and changes in the fair value of open contracts are recognized in the income statement. Loss of hedge accounting may cause volatility in earnings. Fair value is assessed, and measured and estimated by obtaining independent market quotes from counterparties, as well as utilizing Black s (1976) option valuation model based upon underlying forward price curve data, a risk-free interest rate and estimated volatility factors. In addition, forward price curves and estimates of future volatility factors are used to assess and measure the effectiveness of our open contracts at the end of each period. The fair values we report in our financial statements change as estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Taxes. We are subject to income taxes at the federal level and in the states where we operate. Significant judgment is required in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from these estimates, which could impact our financial position, results of operations and cash flows.

Stock Compensation Expense. We account for stock-based compensation in accordance with the fair value recognition provisions of SFAS 123(R), Share-Based Payment. Under the fair value recognition provisions of SFAS 123(R), stock-based compensation cost is measured at the grant date based on the value of the award and is recognized as expense over the vesting period. We utilize the Black-Scholes option pricing model to determine the fair value of stock-based awards on the grant date which requires judgment in estimating the expected life of the option and the expected volatility of our stock. Actual results could differ significantly from these estimates, and these differences could materially impact our financial position, results of operations and cash flows.

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

Recent Accounting Pronouncements

During 2006, we adopted SFAS 123(R), Share-Based Payment, using the modified prospective method as defined by SFAS 123(R); SFAS 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans; and the SEC Staff Accounting Bulletin No.108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements (SAB 108). The adoption of these new pronouncements did not have a material impact on our financial statements. In addition, see Consolidated Financial Statements, Note 1 Summary of Organization and Significant Accounting Policies *Recent Accounting Pronouncements* for discussions of SFAS 157, Fair Value Measurements and Financial Accounting Standards Board (FASB) Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement 109 (FIN 48). We are currently evaluating the impact of adopting SFAS 157 and FIN 48 and do not expect their adoption will have a material impact on our results of operations or financial position.

Overview of 2006 Results

During 2006, we successfully implemented our plan to restructure our business to become a pure onshore operator with the completion of the sale of substantially all of our Gulf of Mexico properties. The completion of the sale of our Texas offshore properties on March 31, 2006 and our Louisiana offshore properties on June 1, 2006 had a significant impact on our 2006 operating results. Reserves, production volumes, revenues, operating expenses and cash flows were all lower during 2006 than prior-year levels and are expected to remain lower unless reserves and production from the properties sold are replaced in full.

While total company reserves, production, net operating revenues and cash flows declined as a direct result of the sale of our offshore assets, our total onshore reserves increased 13% year-over-year to 697 Bcfe. Our primary source of onshore reserve additions during 2006 was through the drill bit. Our acquisition activity during 2006 was significantly less than in the prior three-year period, as we added just 32 Bcfe from acquisitions during 2006 compared to a total of 293 Bcfe added from acquisitions from 2003 through 2005. Our plan for reinvestment of the proceeds from the sale of our offshore assets included a balanced approach and despite having a large pool of cash available for reinvestment in onshore natural gas and oil assets, we were unable to fully utilize the sales proceeds to acquire producing properties and take full advantage of the tax benefits provided by like-kind reinvestment, as the acquisition market for attractive, well-priced onshore properties was extremely competitive.

With the shift in focus to onshore operations during 2006 and the expansion of our onshore capital exploration and development drilling program, we were able to increase onshore production by 8% year-over-year. This increase was realized despite third party pipeline capacity constraints that continued throughout the year in the Rockies and that were experienced throughout the second half of the year in East Texas and Arkoma, as the supply of natural gas in these regions increased primarily due to industry-wide expansion of drilling within these areas.

Natural gas prices declined sharply during the third quarter and into the fourth quarter of 2006 from the record highs set during the third and fourth quarters of 2005 after Hurricanes Katrina and Rita and reached lows not seen since November 2002 due, in part, to historically high levels of U.S. natural gas storage. As a result of this decline in gas prices, our cash losses on the settlement of derivative contracts narrowed considerably from the first and second quarters of 2006 and from the third and fourth quarters of 2005. Along with this decline in natural gas prices, we began to see some stabilization in rig rates and other service costs during the second half of the year. Despite this, our depreciation, depletion and amortization rate increased year-over-year primarily as a result of higher onshore finding and development costs during 2006 and an increase in estimated future development costs. In addition, due to the cumulative effect of higher finding and development costs during recent years, combined with higher estimated future operating and development costs at year-end 2006, we were required under full cost accounting rules to write down or impair the carrying value of our natural gas and oil properties by $19.0 million ($12.3 million net of tax) during the fourth quarter of 2006. See Consolidated Financial Statements, Note 1 Summary of Organization and Significant Accounting Policies Natural Gas and Oil Properties, for further discussion of full cost accounting.

Net cash proceeds of $721.6 million from the sale of our offshore assets were ultimately used to repay all of our outstanding borrowings under our bank credit facility, with the balance used for working capital purposes, including the funding of our 2006 capital expenditure program. Throughout 2006, we borrowed under our bank credit facility to fund exploration and development activities, several smaller producing property acquisitions, a significant net profits payment that was triggered by the sale of certain offshore fields, cash settlements of derivative contracts, including the liquidation of a portion of our open contracts that was required under our bank credit facility after completion of the sale of our offshore assets, and repurchases of our common stock. We were unable to fully reinvest the $323.7 million initially escrowed for like-kind exchange transactions under Section 1031 prior to expiration of the qualified reinvestment period in November 2006, and the remaining funds were released. However, upon the release of the escrowed funds, we were able to repay all accumulated bank borrowings then outstanding and fund our 2006 federal income tax obligation incurred in connection with taxable gain recognized on the sale our offshore assets, leaving us with approximately $54 million in cash and $175 million in long-term debt under our senior subordinated notes at December 31, 2006.

These factors were the primary drivers behind results of operations, net income and cash flows during 2006. During 2006:

§ We generated $67.8 million in net income, a decrease of 36% from $105.2 million in 2005;

§ We produced 88 Bcfe compared to 114 Bcfe produced in 2005, and our average daily production rate was 242 MMcfe per day compared to 313 Mcfe/day during 2005, a decrease of 23%;

§ Our net proved reserves totaled 699 Bcfe at year-end 2006, a decrease of 19% from 861 Bcfe at year-end 2005. We sold offshore assets representing 234 Bcfe and we added a net 161 Bcfe, which included 160 Bcfe added through the drill bit plus 32 Bcfe added through acquisitions less 31 Bcfe in downward revisions due primarily to quantities becoming uneconomic at the lower market prices in effect at December 31, 2006. With the total net additions of 161 Bcfe, we replaced 183% of the 88 Bcfe produced in 2006;

§ We generated net cash proceeds from the sale of substantially all of our Gulf of Mexico assets of $721.6 million. Initially, we used $374 million to repay bank debt, escrowed $323.7 million with qualified intermediaries for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal

Revenue Code and used the balance or, approximately $23.9 million, for working capital purposes;

§ Effective June 1, 2006, and following the completion of the sale of our Gulf of Mexico assets, the borrowing base on our bank credit facility was reduced from $600 million to $500 million, where it remained at December 31, 2006;

§ During the third and fourth quarters, we withdrew previously escrowed funds from the sale of our Gulf of Mexico assets, of which $2.2 million was reinvested in qualified natural gas and oil assets and the balance, or $321.5 million, was released from escrow due to the expiration of the 180-day qualified reinvestment periods;

§ Upon release of the remaining escrowed funds in November, we repaid all outstanding borrowings under our bank credit facility, thereby reducing total bank borrowings by a net $422 million during the year;

§ Following the release of the escrowed funds for which qualified reinvestments in natural gas and oil properties were not achieved, we recognized a taxable gain on the sale of our Gulf of Mexico assets of $264 million and utilized all of our net operating loss carryforwards to partially offset the taxable gain. As a result, in November, we made a cash payment for estimated federal income taxes for 2006 of $34.0 million;

§ We generated $416.2 million in net cash flows from operating activities compared to $460.5 million during 2005, a decrease of 10%;

§ We spent $612.8 million under our 2006 capital program for investments in natural gas and oil properties, a decrease of 18% from 2005. Our 2006 expenditures included $64.7 million for producing property acquisitions compared to $197.7 million spent on acquisitions in 2005, a decrease of 67%;

§ We drilled 363 wells, of which 329, or 91%, were successful with 2 offshore, 28 in East Texas, 71 in Arkoma, 90 in South Texas and 138 in the Rockies;

§ In South Texas, we integrated the producing properties acquired in November 2005 from Kerr-McGee, acquired a 3D seismic survey covering approximately 1,000 square miles in the Vicksburg trend, and began our drilling program on the acquired properties during April 2006, successfully completing 36 wells within the Rincon, Tijerina-Canales-Blucher and Vaquillas Ranch Fields by year end. In December, we acquired a 100% working interest in ten producing wells located in Webb County, Texas, from Legend Natural Gas, for $4.3 million, with estimated proved reserves of 1.8 Bcfe;

§ In Arkoma, we continued to expand our developmental drilling program and implemented successful recompletion and compression programs designed to improve operating efficiencies and minimize production downtime. In addition, we participated with a 40% working interest in eight successful wells, adding approximately 20 new locations for future drilling, in the new Rich Mountain Field located in close proximity to our Chismville Field in Logan County, Arkansas;

§ In East Texas, we continued the expansion of our operating base begun in 2005 and focused our drilling efforts on properties acquired in 2005. In April 2006, we acquired additional producing properties and acreage adjacent to our Willow Springs Field with an estimated 16.2 Bcfe of proved reserves as of January 1, 2006, from Samson Lone Star Limited Partnership for a net purchase price of $21.3 million;

§ In the Rocky Mountains, we completed and began processing a 150 square mile 3D seismic survey in the DJ Basin and successfully drilled and completed 100 new wells within the Niobrara Trend. During the first quarter of 2006, we initiated the second phase of our DJ Basin gathering system, bringing on-line more than 50 wells drilled during 2005. For the year, we added a net 24 Bcfe through the drill bit, which includes downward revisions of 4 Bcfe, primarily as a result of price economics. Average daily production increased approximately 60% to 8 MMcfe per day. In December, we acquired incremental working interests and interests in new producing properties and undeveloped acreage located in the DJ Basin with an estimated 14.2 Bcfe of proved reserves as of November 1, 2006, from Santos TOG Corp. for a net purchase price of $21.4 million;

§ During May and June, we repurchased 1,176,500 shares, or approximately 4%, of our outstanding common stock, in the open market for approximately $61.6 million. These repurchases were funded with cash on hand and borrowings under our bank credit facility;

§ During June, we paid $14.3 million to liquidate and settle derivative contracts covering 60,000 MMBtu per day for each of the months July through December 2006, reducing our volume hedged from 250,000 MMBtu per day to 190,000 MMBtu per day as required by our bank credit facility in connection with our Gulf of Mexico sale. In addition, during August, we paid $0.9 million to liquidate and settle derivative contracts covering 20,000 MMBtu per day for each of the months September and October 2006, for a total of $15.2 million paid to liquidate derivative contracts during 2006;

§ As a result of the settlement and liquidation of derivative contracts during 2006, combined with significantly lower market prices for natural gas and fewer open contracts covering 2007 and 2008 production volumes at year-end 2006, the fair market value of our open derivatives contracts decreased from a liability of $417.7 million ($269.8 million net of tax) at December 31, 2005 to a liability of $27.4 million ($17.5 million net of tax) at December 31, 2006. The decline of natural gas prices during the third and fourth quarters was a key factor in the decline in our losses from hedging activities that totaled $64.5 million for 2006 compared to a total net loss of $264.5 million incurred during 2005, of which $116.5 million was incurred during the fourth quarter of 2005; and

§ At December 31, 2006, due to the cumulative effect of higher finding and development costs during recent years, combined with higher estimated future operating and development costs at year-end 2006, we recorded a writedown in the carrying value of our natural gas and oil properties, taking a non-cash charge and reduction to earnings in the fourth quarter of approximately $19.0 million ($12.3 million net of tax).

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Operating and Financial Results for 2006 compared to 2005 and Operating and Financial Results for 2005 compared to 2004.

The comparability of our operating and financial results for 2006 to 2005 was significantly impacted by the sale of substantially all of our Gulf of Mexico assets during the first half of 2006 and the continued effects of production curtailments caused by damage to third party pipelines and processing facilities from the 2005 Hurricanes Katrina and Rita on these offshore assets prior to the completion of their sale on June 1, 2006. Our operating results for the year ended December 31, 2006 include production, revenues and expenses relating to our Texas Gulf of Mexico properties until the completion of their sale on March 31, 2006 and our Louisiana Gulf of Mexico properties until the completion of their sale on June 1, 2006.

For 2005, the comparability of operating and financial results to 2004 was significantly impacted by offshore production curtailments caused by Hurricanes Katrina and Rita during August and September 2005.

	Year Ended December 31,				Year Ended December 31,			
Summary Operating Information:	**2006**	**2005**	**Change**	**%**	**2005**	**2004**	**Change**	**%**
	(in thousands, except prices and percentages)							
Operating revenues	$531,597	$621,543	$(89,946)	-14%	$621,543	$650,439	$(28,896)	-4%
Operating expenses	404,749	436,807	(32,058)	-7%	436,807	382,626	54,181	14%
Income from operations	126,848	184,736	(57,888)	-31%	184,736	267,813	(83,077)	-31%
Net income	67,783	105,169	(37,386)	-36%	105,169	162,824	(57,655)	-35%
Production:								
Natural gas (MMcf)	82,528	105,809	(23,281)	-22%	105,809	115,855	(10,046)	-9%
Oil (MBbls)	938	1,417	(479)	-34%	1,417	1,355	62	5%
Total (MMcfe) (1)	88,156	114,311	(26,155)	-23%	114,311	123,985	(9,674)	-8%
Average daily production (MMcfe/d)	242	313	(71)	-23%	313	339	(26)	-8%
Average Sales Prices:								
Natural Gas (per Mcf) unhedged	$ 6.56	$ 7.71	$ (1.15)	-15%	$ 7.71	$ 5.78	$ 1.93	33%
Natural Gas (per Mcf) realized (2)	5.72	5.21	0.51	10%	5.21	5.19	0.02	
Natural Gas (per Mcf) all-in (3)	5.77	5.21	0.56	11%	5.21	5.17	0.04	1%
Oil (per Bbl) realized	56.56	48.43	8.13	17%	48.43	36.85	11.58	31%

(1) MMcfe is defined as one million cubic feet equivalent of natural gas, determined using the ratio of six MMcf of natural gas to one MBbl of crude oil, condensate or natural gas liquids.

(2) Includes gains and losses

realized on derivative contracts settled during the period.

(3) Includes gains and losses realized on derivative contracts settled during the period, as well as unrealized gains and losses recognized pursuant to SFAS 133, Accounting for Derivative Instruments and Hedging Activities.

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Production Volume

	Year Ended December 31,				Year Ended December 31,			
	2006	2005	Change	%	2005	2004	Change	%
	(in thousands, except percentages)							
Natural Gas Production (MMcf):								
Onshore	71,377	68,009	3,368	5%	68,009	67,477	532	1%
Offshore	11,151	37,800	(26,649)	-71%	37,800	48,378	(10,578)	-22%
Total natural gas	82,528	105,809	(23,281)	-22%	105,809	115,855	(10,046)	-9%
Oil (MBbls):								
Onshore	505	102	403	395%	102	70	32	46%
Offshore	433	1,315	(882)	-67%	1,315	1,285	30	2%
Total oil	938	1,417	(479)	-34%	1,417	1,355	62	5%
Natural Gas Equivalent (MMcfe):								
Onshore	74,407	68,621	5,786	8%	68,621	67,897	724	1%
Offshore	13,749	45,690	(31,941)	-70%	45,690	56,088	(10,398)	-19%
Total equivalents	88,156	114,311	(26,155)	-23%	114,311	123,985	(9,674)	-8%

The following table provides a comparison of average daily production by area:

	Year Ended December 31,				Year Ended December 31,			
	2006	2005	Change	%	2005	2004	Change	%
Natural Gas Equivalent (MMcfe per day):								
South Texas	143	134	9	7%	134	142	(8)	-6%
Arkoma	40	43	(3)	-7%	43	38	5	13%
East Texas	12	5	7	140%	5	2	3	150%
Rockies	8	5	3	60%	5	1	4	400%
Other	1	1			1	3	(2)	-67%
Total onshore	204	188	16	8%	188	186	2	1%
Offshore	38	125	(87)	-70%	125	153	(28)	-19%
Total	242	313	(71)	-23%	313	339	(26)	-8%

Production Volume for 2006 compared to 2005. Primarily as a result of the sale of substantially all of our Gulf of Mexico assets during the first half of 2006, our total production volumes were 23% lower during 2006 compared to

2005.
Onshore. During 2006, average daily production from our onshore properties increased by 9%. In South Texas, production increased 7% year-over-year, due primarily to the acquisition of properties from Kerr-McGee Oil and Gas Onshore LP and Westport Oil and Gas Company, L.P. in November 2005 and the results of subsequent developmental drilling activity on these properties. In Arkoma, average daily production declined 7% during 2006, due in part to curtailments throughout the second half of 2006 caused by oversupply in the gathering system. In East Texas, production increased by 7 MMcfe per day, or 140%, year-over-year, due to our acquisition of acreage and producing wells during 2005 and 2006, combined with our subsequent development drilling activity, which resulted in the successful drilling of 28 new wells in 2006 and 16 during 2005. However, our production in East Texas was curtailed periodically throughout much of 2006 due to third party pipeline constraints combined with rig delays. In the Rockies, we continued to add production and connect completed wells to sales, as evidenced by our average daily production rates, which increased by 3 MMcfe per day, or 60%, year-over-year. However, we also experienced curtailments in Utah during the last three quarters of 2006 due to compressor issues, high line pressure and fluids in third party gathering lines that limited production flow.
Offshore. For 2006, offshore production is comprised of production from our Louisiana Gulf of Mexico assets during the first five months of 2006 and production from our Texas Gulf of Mexico assets during the first three months of 2006, as the sales of these assets were completed on June 1, 2006 and March 31, 2006, respectively. For 2006, offshore production totaled 13.7 Bcfe compared to 45.7 Bcfe during 2005, a decrease of 70%. During the first quarter of 2006, we continued to experience hurricane-related curtailments as a result of the damage to third party pipelines and facilities. We estimate that approximately 34 MMcfe per day or, 3.1 Bcfe, was curtailed and deferred during the first quarter, primarily at Eugene Island 331 and Vermilion 369 and 408.

Production Volume for 2005 compared to 2004. Production volumes were 8% lower in 2005 compared to 2004, due primarily to curtailments of offshore production caused by Hurricanes Katrina and Rita and the natural production decline of our existing property base as we were delayed in bringing on-line new production offshore and in the DJ Basin.

Onshore. Daily production rates for 2005 were slightly higher than the prior year, averaging 188 MMcfe per day compared to 186 MMcfe per day during 2004. Through development drilling we added approximately 5 MMcfe per day in Arkoma and 3 MMcfe per day in East Texas. We continued our exploration efforts in the Rockies, where we experienced delays in bringing production from the DJ Basin wells on-line, but added approximately 4 MMcfe per day in the region for the year. Growth in these areas was offset by production declines in South Texas, as our existing property base matured. Year-over-year, 2004 onshore volumes included production from our South Louisiana properties sold in February 2004 and the disposition of our Appalachian Basin properties in June 2004.

Offshore. Daily production rates decreased by 19%, or 28 MMcfe per day, from an average of 153 MMcfe per day during 2004 to an average of 125 MMcfe per day in 2005. For the first eight months of 2005, offshore production rates were lower than prior year levels due in part to delays in our development program caused by delays in rig availability during the first half of 2005 and in part to (i) an unsuccessful side-track at High Island 115; (ii) lower production rates at High Island 47 subsequent to a side-track completed in the second quarter; and (iii) declining production rates at High Island A283, Galveston 389 and East Cameron 81/84, all key producing fields during 2004. At the end of August 2005, pre-storm production was estimated at 155 MMcfe per day, primarily as a result of newly developed production at Galveston 210, Matagorda A-5, West Cameron 77, Main Pass 264 and Mustang Island 858. We estimate that approximately 10.6 Bcfe or 30 Mcfe per day on an annualized basis was shut-in and deferred during the last four months of 2005 as a result of Hurricanes Katrina and Rita.

Commodity Prices and Effects of Hedging Activities

	Year Ended December 31,				**Year Ended December 31,**			
	2006	**2005**	**Change**	**%**	**2005**	**2004**	**Change**	**%**
Average Natural Gas Prices ($ per Mcf):								
Onshore	$ 6.33	$ 7.44	$ (1.11)	-15%	$ 7.44	$ 5.61	$ 1.83	33%
Offshore	7.97	8.21	(0.24)	-3%	8.21	6.01	2.20	37%
Total Natural Gas unhedged	6.56	7.71	(1.15)	-15%	7.71	5.78	1.93	33%
Total Natural Gas realized (1)	5.72	5.21	0.51	10%	5.21	5.19	0.02	
Total Natural Gas all-in (2)	5.77	5.21	0.56	11%	5.21	5.17	0.04	1%
Average Oil Prices ($ per Bbl):								
Onshore	$54.31	$53.59	$ 0.72	1%	$53.59	$37.73	$15.86	42%
Offshore	59.18	48.03	11.15	23%	48.03	36.81	11.22	30%
Total Oil	56.56	48.43	8.13	17%	48.43	36.85	11.58	31%

(1) Includes gains and losses realized on derivative contracts settled during the

period.

(2) Includes both gains and losses realized on derivative contracts settled during the period, as well as unrealized gains and losses recognized pursuant to SFAS 133.

Commodity Prices and Effects of Hedging Activities for 2006 compared to 2005. For 2006, our average unhedged price for natural gas decreased by 15% from $7.71 per Mcf during 2005 to $6.56 per Mcf during 2006. As a result of the cash loss from derivative contracts settled during 2006, we realized an average natural gas price during 2006 of $5.72 per Mcf which was 87% of, or $0.84 per Mcf lower than, our average unhedged price of $6.56 per Mcf of the year. The decline in the market price for natural gas throughout 2006 allowed us to reduce our cash loss on settled derivative contracts to $69.2 million during 2006 compared to a cash loss of $265.2 million during 2005.

Commodity Prices and Effects of Hedging Activities for 2005 compared to 2004. For 2005, our average unhedged price for natural gas increased by 33% from $5.78 per Mcf during 2004 to $7.71 per Mcf during 2005. Because NYMEX prices traded above our average hedged ceiling during all 12 months of 2005, our total loss from hedging activities increased by $194.4 million year-over-year, with approximately 60% of the increase occurring in the last four months of 2005 due to the spike in NYMEX prices, trading in a range between $11.00 per MMBtu to $14.00 per MMBtu, after Hurricanes Katrina and Rita. As a result of the cash loss from derivative contracts settled during 2005, we realized an average natural gas price during the year of $5.21 per Mcf which was 68% of, or $2.50 per Mcf lower than, our average unhedged price of $7.71 per Mcf of the year. During 2004, we incurred a total loss from natural gas hedging activities of $70.1 million, which included an unrealized loss of $1.9 million recognized for ineffectiveness of open contracts. As a result of the $68.2 million cash loss from derivative contracts settled during 2004, we realized an average price of $5.19 per Mcf, which was 90% of, or $0.59 per Mcf lower than, our average sales price of $5.78 per Mcfe during the year.

Gains (Losses) from Hedging Activities. The following table summarizes and compares the components of our realized and unrealized gains and losses due to derivative contracts and hedging activities for the years ended December 31, 2006, 2005 and 2004. All of the non-cash, unrealized gains and losses shown in the table result from accounting for derivative instruments under SFAS 133. During the fourth quarter of 2005 and the first quarter of 2006, a portion of our derivative contracts became ineffective as hedges due to a loss of correlation between the sales point index and NYMEX. Finally, during the first quarter of 2006 and in conjunction with our entry into an agreement on February 28, 2006 to sell the Texas portion of our Gulf of Mexico assets, the remaining portion of all our open derivative contracts ceased to qualify for hedge accounting. As a result, all open derivative contracts were subsequently accounted for using mark-to-market accounting with subsequent changes in fair value accounted for as increases or decreases to natural gas and oil revenues. The use of mark-to-market accounting has caused and is expected to continue to cause volatility in our natural gas and oil revenues during future periods. All amounts in the following table are shown on a pre-tax basis and are included in our statement of operations on the line item natural gas and oil revenues.

	Year Ended December 31,			Year Ended December 31,		
	2006	2005	Change	2005	2004	Change
	(in thousands)					
Gain (Loss) from Hedging Activities						
Cash (loss) realized on contracts settled[1]	$ (69,208)	$ (265,236)	$ 196,028	$ (265,236)	$ (68,195)	$ (197,041)
Non-cash unrealized gain (loss):						
Ineffectiveness gain (loss)[2]	45,912	(46,000)	91,912	(46,000)	(1,950)	(44,050)
Mark-to-market change in fair value gain (loss)[3]	37,660	26,094	11,566	26,094		26,094
Deferred gain (loss) due to fourth quarter 2005 production shortfalls[4]	(20,600)	20,600	(41,200)	20,600		20,600
Recognition of all deferred losses relating to Gulf of Mexico production sold[5]	(58,215)		(58,215)			
Total non-cash unrealized gain (loss)	4,757	694	4,063	694	(1,950)	2,644
Total gain (loss) from hedging activities	$ (64,451)	$ (264,542)	$ 200,091	$ (264,542)	$ (70,145)	$ (194,397)

(1) For 2006, also includes (i) $14.3 million paid during the second quarter of

2006 to liquidate and settle contracts covering 60,000 MMBtu per day for each of the months July through December 2006, which liquidiation was made following the completion of the sale of our Gulf of Mexico assets on June 1, 2006 and was required under the terms of our bank credit facility; and (ii) $0.9 million paid during the third quarter of 2006 to liquidate and settle contracts covering 20,000 MMBtu per day for each of the months September and October 2006.

(2) For 2006, 2005 and 2004, includes ineffective portion of open contracts recognized at the end of the period that were not eligible for deferral under SFAS 133.

(3) For 2006, includes change in fair market value of open contracts

subsequent to loss of hedge accounting during the first quarter. For 2005, includes change in fair market value of open contracts allocated to the Houston Ship Channel index that lost correlation with the NYMEX price during the fourth quarter of 2005 caused by Hurricanes Katrina and Rita.

(4) For 2006, includes recognition of the loss related to cash settlements made during the fourth quarter of 2005 that was deferred during the fourth quarter of 2005 in accumulated other comprehensive income. This deferred loss resulted from offshore production shortfalls during the fourth quarter of 2005 caused by Hurricanes Katrina and Rita.

(5) For 2006, includes recognition in earnings of all

losses previously deferred in accumulated other comprehensive for which the underlying production was attributable to Gulf of Mexico assets sold.

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Natural Gas and Oil Revenues

	Year Ended December 31,				Year Ended December 31,			
	2006	2005	Change	%	2005	2004	Change	%
	(in thousands, except percentages)							
Natural Gas Revenues:								
Onshore	$ 452,166	$ 505,719	$ (53,553)	-11%	$ 505,719	$ 378,450	$ 127,269	34%
Offshore	88,819	310,463	(221,644)	-71%	310,463	290,844	19,619	7%
Gain (loss) on settled derivatives	(69,208)	(265,236)	196,028	-74%	(265,236)	(68,195)	(197,041)	289%
Unrealized gain (loss) on derivatives	4,757	694	4,063	585%	694	(1,950)	2,644	-136%
Total natural gas revenues	476,534	551,640	(75,106)	-14%	551,640	599,149	(47,509)	-8%
Oil Revenues:								
Onshore	27,428	5,466	21,962	402%	5,466	2,641	2,825	107%
Offshore	25,624	63,165	(37,541)	-59%	63,165	47,297	15,868	34%
Total oil revenues	53,052	68,631	(15,579)	-23%	68,631	49,938	18,693	37%
Total natural gas and oil revenues	$ 529,586	$ 620,271	$ (90,685)	-15%	$ 620,271	$ 649,087	$ (28,816)	-4%

For 2006, natural gas revenues from our onshore properties declined by $53.6 million, or 11%, from levels in 2005 due primarily to average unhedged natural gas prices that were 15%, or $1.11 per Mcf, lower year-over-year. This price related decline was partially offset by a 5% increase in onshore natural gas production volume during 2006. Of the $53.6 million decline in onshore natural gas revenues year-over-year, approximately $78.6 million was a result of average unhedged natural gas prices that were $1.11 per Mcf lower in 2006 than in 2005 offset in part by an increase of approximately $25.0 million as a result of 3.4 Bcf more in natural gas production during 2006 than in 2005.
Lower natural gas prices during the second half of 2006 narrowed our net loss on derivatives settled during the year by $196.0 million. The lower natural gas prices, combined with a reduction in the aggregate size of our hedge portfolio, caused our unrealized net gains on open derivative contracts to increase from a gain of $0.7 million during 2005 to a gain of $4.7 million during 2006.

The increase in the market price for oil combined with an increase in our onshore oil production of 403 MBbls, or 395%, during 2006, added approximately $22.0 million in onshore oil revenues year-over-year. The increase in onshore oil revenues during 2006 was due primarily to oil and natural gas liquids production from the South Texas properties acquired in November 2005.

For 2005, onshore natural gas revenues increased by $127.3 million, or 34%, from 2004, primarily as a result of unhedged natural gas prices that were $1.83 per Mcf higher than the average unhedged price received in 2004, combined with a 1% increase in onshore natural gas production during 2005. For 2005, the higher unhedged prices contributed to an increase in onshore natural gas revenues of approximately $124.4 million, with the 0.5 Bcf increase in production contributing the remaining $2.9 million of the year-over-year increase. Offshore, natural gas revenues increased by $19.6 million, or 7%, from 2004, primarily as a result of unhedged natural gas prices that were $2.20 per Mcf higher than the average unhedged price received in 2004, offset in part by lower natural gas production resulting from hurricane related curtailments and delays. For 2005, higher unhedged natural gas prices caused offshore natural gas revenues to increase by approximately $83.2 million, offset in part by a decline of approximately $63.6 million caused by lower offshore natural gas production of approximately 10.6 Bcf.

During 2005, NYMEX prices traded above our average hedged ceiling price during all 12 months of 2005, and as a result our total loss from hedging activities increased by $194.4 million year-over-year, with approximately 60% of the increase occurring in the last four months of 2005 due to the spike in NYMEX prices after Hurricanes Katrina and Rita.

The increase in the market price for oil during 2005 was the primary cause of the $18.7 million increase in our total oil revenues from 2004. Our total average realized price for oil increased by approximately $11.58 per Bbl, which accounted for $16.4 million of the increase in total oil revenues year-over-year, combined with an increase in total oil production of 62 MBbls during 2005, which added approximately $2.3 million in oil revenues year-over-year.

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Operating Expenses

	Year Ended December 31,				Year Ended December 31,			
	2006	2005	Change	%	2005	2004	Change	%
	($ per MMcfe, except percentages)							
Lease operating expense	$ 0.73	$ 0.59	$ 0.14	24%	$ 0.59	$ 0.45	$ 0.14	31%
Severance tax	0.21	0.16	0.05	31%	0.16	0.10	0.06	60%
Transportation expense	0.12	0.10	0.02	20%	0.10	0.10		%
Asset retirement accretion expense	0.04	0.05	(0.01)	-20%	0.05	0.04	0.01	25%
Depreciation, depletion and amortization	2.88	2.58	0.30	12%	2.58	2.14	0.44	21%
Writedown in carrying value	0.22		0.22	100%				
General and administrative, net	0.41	0.34	0.07	21%	0.34	0.27	0.07	26%
Total operating expenses per unit of production	$ 4.61	$ 3.82	$ 0.79	21%	$ 3.82	$ 3.10	$ 0.72	23%

During 2006, total operating expenses on an absolute dollar basis decreased by 7%, from $436.8 million during 2005 to $404.7 million during 2006, primarily as a result of lower lease operating expense, depreciation, depletion and amortization expense and asset retirement accretion expense following the sale of substantially all of our Gulf of Mexico assets during the first half of 2006, offset in part by the writedown in the carrying of our natural gas and oil properties during the fourth quarter of 2006. Despite the above absolute dollar declines, on a unit of production basis, operating expenses increased by $0.79 per Mcfe, or 21%, from 2005 to 2006. Per unit expenses were higher for all categories of operating expense, other than asset retirement accretion expense and the writedown in carrying value of our natural gas and oil properties, due to a lower level of production during 2006 following the sale of our offshore producing assets. Also contributing to these higher per unit expenses was the continued upward pressure on service costs, labor, materials, insurance and property taxes resulting from the sustained strength of commodity prices versus historical levels during the first half of 2006.

During 2005, total operating expenses increased on an absolute dollar basis by 14% over 2004, primarily as a result of higher lease operating expenses, depreciation, depletion and amortization expense and general and administrative expenses. On a unit of production basis, total operating expenses increased $0.72 per Mcfe, or 23%, from 2004 to 2005. Per unit expenses were higher for all categories of operating expense during 2005 due to curtailed production during the last four months of the year combined with higher costs during 2005. Depreciation, depletion and amortization accounted for $0.44 of the 2005 increase, with lease operating expense adding $0.14 and non-recurring general and administrative expenses contributing $0.12.

Lease Operating Expense. The following table summarizes our lease operating expenses on both an absolute dollar and unit of production basis for onshore and offshore properties for the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,				Year Ended December 31,			
	2006	2005	Change	%	2005	2004	Change	%
	(in thousands, except percentages)							
Onshore	$ 47,077	$ 27,868	$ 19,209	70%	$ 27,686	$ 22,075	$ 5,611	25%
Offshore	16,882	39,928	(23,046)	-58%	39,928	33,850	6,078	18%
Total	$ 63,959	$ 67,796	$ (3,837)	-6%	$ 67,796	$ 55,925	$ 11,871	21%

Onshore per Mcfe	$ 0.63	$ 0.41	$ 0.22	54%	$ 0.41	$ 0.33	$ 0.08	24%
Offshore per Mcfe	1.23	0.87	0.36	41%	0.87	0.60	0.27	45%
Total	0.73	0.59	0.14	24%	0.59	0.45	0.14	31%

On an absolute dollar basis, total lease operating expense decreased by 6% during 2006 as compared to 2005 The year-over-year decrease from 2005 to 2006 reflects the disposition of substantially all of our offshore assets during the first half of 2006, offset in part by an increase of $19.4 million in lease operating expenses attributable to our onshore properties. The increase in onshore lease operating expenses year-over-year is due to a combination of factors, including (i) the continued expansion of our onshore operating base through the acquisition of approximately 300 producing wells in South Texas during the fourth quarter of 2005 and the addition of 329 newly developed wells since the end of 2005; (ii) higher costs to operate and maintain our existing property base; and (iii) continued upward pressure on service costs, labor, materials, insurance and property taxes throughout much of 2006. While we remain committed to minimizing our operating cost structure, we expect that lease operating expenses will continue to increase as long as commodity prices remain strong, fueling the demand for field services.

On an absolute dollar basis, lease operating expense for 2005 increased by 21% from 2004 levels. The year-over-year increase from 2004 to 2005 related primarily to higher service costs and the continued expansion of our operating base from the escalation of our drilling program during each of the respective years and the acquisition of new properties. Gulf of Mexico lease operating expenses increased significantly during 2004 and 2005 as a direct result of the acquisition of the Transworld properties in the fourth quarter of 2003 and the BP and Orca properties in September and October of 2004. These properties were mature assets, acquired primarily for exploitation opportunities, and operated under higher cost structures than our existing offshore base. During 2004 and 2005, we integrated these assets into our Gulf of Mexico base and worked to reduce overall operating expenses.

Severance Tax. Severance tax is a function of production volumes and revenues generated from onshore production. During 2006, severance tax expense on an absolute dollar basis was flat compared to 2005 due in part to high-cost/tight-gas credits received for a portion of our 2006 South Texas production combined with lower wellhead prices during the second half of 2006. On a per unit of production basis, 2006 average rates were $0.05 per Mcfe higher than prior year, as total company production volumes declined following the sale of substantially all of our offshore assets during 2006. During 2005, severance tax increased by 52% on an absolute dollar basis and $0.06 per Mcfe, primarily as a result of the 33% increase in the market price for natural gas during 2005 as compared to 2004.

Depreciation, Depletion and Amortization. For 2006, the 14% decrease in our depreciation, depletion and amortization expense compared to 2005 was primarily a result of lower production volumes subsequent to the sale of our offshore producing assets, offset in part by higher depletion rates during 2006. Our total depreciation, depletion and amortization rate increased 12%, or $0.30 per Mcfe, from $2.58 per Mcfe during 2005 to $2.88 per Mcfe during 2006. The higher depletion rate during 2006 is a result of a 30% increase in our onshore finding and development costs and a 14% increase in onshore future development costs year-over-year, despite the sale of our Gulf of Mexico assets, combined with the impact on reserve quantities of lower average wellhead prices for natural gas at December 31, 2006. We incurred downward revisions of 31 Bcfe during 2006, due to a combination of reserve performance and quantities becoming uneconomic at the lower market prices at December 31, 2006.

For 2005, the increase in our depreciation, depletion and amortization expense compared to 2004 was primarily a result of a higher depletion rate, offset in part by an 8% decrease in production. Our total depreciation, depletion and amortization rate increased 21% from $2.14 per Mcfe during 2004 to $2.58 per Mcfe during 2005. The higher depletion rate during 2005 is primarily a result of a higher finding, development and acquisition costs incurred during 2005 combined with a 60% increase in future development costs at December 31, 2005 compared to future development costs at the end of 2004. In addition, we incurred downward revisions of 60 Bcfe during 2005, primarily as a result of reservoir performance. These revisions included approximately 14 Bcfe at High Island 115 from an unsuccessful side-track of the B-1 well and approximately 12 Bcfe in the Uinta Basin primarily as a result of a reduction in our working interest from 100% to 50% subsequent to our entering into a joint venture with another operator.

Writedown in Carrying Value of Natural Gas and Oil Properties. At December 31, 2006, we were required under full cost accounting rules to impair or write down the carrying value of our natural gas and oil properties due to the cumulative effect of higher finding and development costs during recent years, combined with higher estimated future operating and development costs at year-end 2006. In calculating our initial ceiling test at December 31, 2006, we estimated that, using an average net wellhead price of $4.94 per Mcf, the carrying value of our full cost pool exceeded the ceiling limitation by approximately $582.8 million ($376.5 million net of tax). However, since December 31, 2006 and prior to filing this Annual Report, the market price for natural gas increased such that, using an average net wellhead price of $6.63 per Mcf on February 20, 2007, the carrying value of our natural gas and oil properties exceeded the ceiling limitation by approximately $19.0 million ($12.3 million net of tax). Accordingly, we recorded a writedown to the carrying value of our natural gas and oil properties and a non-cash charge and reduction to earnings in the fourth quarter of $12.3 million (net of tax).

Asset Retirement Accretion Expense. The decrease in ARO accretion expense from 2005 to 2006 is primarily a result of the sale of substantially all of our Gulf of Mexico assets, offset in part by new abandonment obligations incurred as a result of our 2006 drilling program. The increase in ARO accretion expense from 2004 to 2005 reflects the increase in our abandonment obligations from drilling and acquisitions made during the period.

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General and Administrative Expenses, Net of Overhead Reimbursements and Capitalized General and Administrative Expenses.

	Absolute Dollars Year Ended December 31,				Unit of Production - Mcfe Year Ended December 31,			
General and Administrative Expense	**2006**	**2005**	**Variance**		**2006**	**2005**	**Variance**	
			(dollars in thousands)					
Gross general and administrative expense	$ 58,422	$ 57,412	$ 1,010	2%	$ 0.66	$ 0.50	$ 0.16	32%
Operating overhead reimbursements	(2,194)	(2,158)	(36)	2%	(0.02)	(0.02)		%
Capitalized general and administrative [1]	(20,215)	(16,876)	(3,339)	20%	(0.23)	(0.14)	(0.09)	64%
General and administrative expense, net	$ 36,013	$ 38,378	$ (2,365)	-6%	$ 0.41	$ 0.34	$ 0.07	21%

(1) Includes only those internal general and administrative costs that are directly associated with our acquisition, exploration and development activities, such as salaries, benefits and incentive compensation for geological and geophysical employees and other specifically identifiable non-payroll costs. These capitalized general and administrative costs do not include costs related to production operations, general corporate

overhead or other activities that are not directly attributable to our acquisition, exploration and development efforts.

2006 compared to 2005. For 2006, gross general and administrative expenses were higher than 2005 by $1.0 million, or 2%, and net general and administrative expenses were lower year-over-year by $2.4 million, or 6%. This increase in gross general and administrative expenses during 2006 was due to a combination of factors, including (i) higher salaries, benefits, incentive and stock compensation, legal, consulting and financial advisory fees and office rent and utilities and (ii) additional expenses of approximately $2.3 million, consisting of $1.4 million in bonuses paid to certain employees in connection with the completion of the sale of our Gulf of Mexico assets and approximately $0.9 million in severance payments to certain employees in our offshore group who were terminated following the sale of the assets. These increases during 2006 were partially offset by certain additional expenses incurred during the 2005 including (i) $5.0 million in connection with the February 2005 renegotiation of executive employment agreements (see Consolidated Financial Statements, Note 6 Related Party Transactions *Employment Agreements*) and (ii) $4.7 million in additional outside legal and professional advisory fees expensed during 2005 in connection with the review of two corporate transactions that were not consummated. Excluding the $2.3 million in additional expenses during 2006 (of which $1.2 million was capitalized) and the additional $9.7 million in expenses during 2005, gross general and administrative expenses would reflect an increase of $8.4 million, or 18%, and net general and administrative expenses would reflect an increase of $6.2 million, or 22%, for 2006 as compared to 2005.

For 2006, capitalized general and administrative expenses were $3.3 million, or 20% higher than capitalized costs during 2005. This increase, which more than offsets the above noted increase in gross general and administrative expenses, corresponds directly to an increase in salaries, benefits and incentive and stock compensation for our geological and geophysical employees who are directly associated with our acquisition, exploration and development activities and includes approximately $1.2 million in additional compensation for bonuses paid in connection with the sale of our offshore assets during 2006 and approximately $1.1 million in additional costs in connection with our retention bonus plan implemented in July 2005 to retain our technical employees.

On a per-unit of production basis, gross, net and capitalized general and administrative expenses were higher during 2006 and reflect the increase in gross general and administrative expense during 2006, primarily as a result of higher salaries, benefits, incentive and stock compensation, legal, consulting and financial advisory fees and office rent and utilities and the decrease in production volume resulting primarily from the sale of our offshore assets.

	Absolute Dollars Year Ended December 31,				**Unit of Production - Mcfe Year Ended December 31,**			
General and Administrative Expense	**2005**	**2004**	**Variance**		**2005**	**2004**	**Variance**	
	(dollars in thousands)							
Gross general and administrative expense	$ 57,412	$ 49,924	$ 7,488	15%	$ 0.50	$ 0.40	$ 0.10	25%
Operating overhead reimbursements	(2,158)	(2,188)	30	-1%	(0.02)	(0.01)	(0.01)	100%
Capitalized general and administrative[(1)]	(16,876)	(14,837)	(2,039)	14%	(0.14)	(0.12)	(0.02)	17%
General and administrative expense, net	$ 38,378	$ 32,899	$ 5,479	17%	$ 0.34	$ 0.27	$ 0.07	26%

(1) Includes only those internal

general and administrative costs that are directly associated with our acquisition, exploration and development activities, such as salaries, benefits and incentive compensation for geological and geophysical employees and other specifically identifiable non-payroll costs. These capitalized general and administrative costs do not include costs related to production operations, general corporate overhead or other activities that are not directly attributable to our acquisition, exploration and development efforts.

2005 compared to 2004. For 2005, gross general and administrative expenses increased by 15%, or $7.5 million, as compared to 2004. Net general and administrative expenses increased by 17%, or $5.5 million, for the year. During 2005 we incurred additional expenses totaling $13.7 million ($0.12 per Mcfe) that include $5.0 million incurred during the first quarter pursuant to the February 2005 renegotiation of executive employment agreements (see Consolidated Financial Statements, Note 6 Related Party Transactions *Employment Agreements*); $0.9 million in the second quarter together with another $3.8 million in the third quarter for outside professional fees incurred pursuant to the review of two corporate transactions that were not consummated; and $4.0 million in the fourth quarter related to severance and other separation related payments made to certain former employees, including our former Chief Financial Officer.

The year ended December 31, 2004 also includes additional charges to expense which total $9.5 million ($0.08 per Mcfe). We incurred $4.4 million during the second quarter of 2004 which included special bonuses awarded by our Board to several key employees, including our Chief Executive Officer who received $3.2 million, in connection with the KeySpan Exchange and Offering completed in June 2004 (see Consolidated Financial Statements, Note 3 Stockholders Equity *KeySpan Exchange and Offering*). We incurred $5.1 million during the fourth quarter of 2004 related to lump sum severance entitlements for three senior executives whose rights to receive severance and accelerated vesting of options and restricted stock were triggered under the terms of their employment agreements as a result of an organizational realignment of management responsibilities during the fourth quarter of 2004. One executive resigned effective December 14, 2004 and two executives resigned effective March 1, 2005. For 2005, the remaining $1.3 million increase in general and administrative expense was a result of higher outside professional fees, specifically legal and accounting, combined with an increase in stock compensation expense related to both options and restricted stock.

For 2005, capitalized general and administrative expenses were $2.0 million, or 14% higher than capitalized costs during 2004. This increase corresponds directly to an increase in our operations and the salaries, benefits and incentive and stock compensation for our geological and geophysical employees who are directly associated with our acquisition, exploration and development activities.

On a per unit of production basis, gross general and administrative expense increased by $0.10 per Mcfe and net general and administrative expense increased by $0.07 per Mcfe from 2004 to 2005. The increase in both aggregate and net general and administrative expense per Mcfe is a result of a 15% increase in aggregate expense combined with the effect of an 8% decrease in production volume during 2005.

Other Income and Expense, Interest and Taxes

Other Income and Expense. For 2006, other income and expense totaled $13.5 million and was comprised of (i) $8.7 million of interest income earned on cash proceeds from the sale of substantially all of our Gulf of Mexico assets;

(ii) $7.7 million related to refunds of prior years severance tax expense; and (iii) $2.9 million of expense relating to prior period offshore transportation expense that was billed during 2006. The increase in refunds of prior severance tax during 2006 was due primarily to delays in receiving approvals for qualifying wells from the Texas Railroad Commission. For 2005, Other Income and Expense includes (i) income of $2.7 million related to refunds of prior years severance tax expense and (ii) expense of $2.8 million incurred as a result of a payout settlement at East Cameron 82/83 during the first quarter of 2005, whereby our working interest in the A3 well was subsequently reduced from 50% to 35%. For 2004, Other Income and Expense includes two items (i) income of $1.2 million related to refunds of prior year s severance tax expense; and (ii) a $0.2 million write-off of a portion of our debt issuance costs due to the June 2, 2004 reduction in the borrowing base on our bank credit facility upon the disposition of our Appalachian Basin assets in June 2004. In July 2002, we applied for and received from the Railroad Commission of Texas a high-cost/tight-gas formation designation for a portion of our South Texas production. For qualifying wells, production is either exempt from tax or taxed at a reduced rate until certain capital costs are recovered.

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Interest Expense, Net of Amounts Capitalized

Interest and Average Borrowings	Year Ended December 31, 2006	2005	Change		Year Ended December 31, 2005	2004	Change	
	(in thousands, except percentages)							
Interest Expense, net:								
Gross interest [1]	$ 29,661	$ 25,301	$ 4,360	17%	$ 25,301	$ 17,813	$ 7,488	42%
Capitalized interest	(4,455)	(8,766)	4,311	-49%	(8,766)	(8,358)	(408)	5%
Interest expense, net	$ 25,206	$ 16,535	$ 8,671	52%	$ 16,535	$ 9,455	$ 7,080	75%
Average Borrowings:								
Bank credit facility	$ 227,000	$ 211,000	$ 16,000	8%	$ 211,000	$ 112,000	$ 99,000	88%
Senior subordinated notes	175,000	175,000			175,000	175,000		
Total borrowings	$ 402,000	$ 386,000	$ 16,000	4%	$ 386,000	$ 287,000	$ 99,000	34%
Average Interest Rate:								
Bank credit facility [2]	6.81%	5.54%	1.27	23%	5.54%	3.75%	1.79	48%
Senior subordinated notes	7.00%	7.00%			7.00%	7.00%		

(1) Includes commitment fees, letter of credit fees, amortization of deferred financing costs and other non-loan related charges of $1.9 million, $1.2 million and $1.3 million for years ended December 31, 2006, 2005 and 2004, respectively.

(2) Includes letter of credit and commitment fees.

2006 compared to 2005. For 2006, gross interest expense was 17% higher than during 2005 due to a $16 million increase in our average outstanding bank borrowings throughout the year, combined with a 127 basis point increase in the average interest rate for our bank debt. In addition, gross interest expense for 2006 includes an additional

$0.6 million for debt extinguishment incurred in connection with the decrease in the borrowing base of our revolving credit facility upon completion of the Gulf of Mexico asset sale transactions.

Our average bank debt increased after the first quarter of 2005 and through the end of the first quarter of 2006, as we utilized bank borrowings to fund acquisitions in East Texas and South Texas and to settle obligations under derivative contracts. At the end of the first quarter and during the second quarter of 2006, we used a portion of the proceeds from the sale of our Gulf of Mexico assets to repay and reduce bank borrowings by a net $322 million to an outstanding balance of $100 million at June 30, 2006. During the third quarter and fourth quarters of 2006, we increased bank borrowings by a net $87 million, to $187 million, in order to fund our exploration and development activities under our 2006 capital program. In November 2006, and upon release of the balance of the previously escrowed funds remaining from the sale of our Gulf of Mexico assets, we repaid all outstanding borrowings under our bank credit facility. Although the majority of our bank debt bore interest at LIBOR-based rates, average interest rates for 2006 were affected by four rate increases by the Federal Reserve during the year. Average interest rates on our bank debt are expected to increase if the Federal Reserve continues to increase interest rates.

Capitalized interest declined by 49% during 2006, as compared to amounts capitalized during 2005. This decline corresponds directly to the $75.8 million decrease in the balance of our unevaluated properties related to our Gulf of Mexico assets that were sold during the first half of 2006. Our unevaluated property balance is expected to remain lower than historical levels given the lower cost structure of onshore projects and the shorter timeline to complete the evaluation of onshore projects. Accordingly, capitalized interest is expected to be lower and, in turn, interest expense is expected to be higher as a result of the shift in our operating focus onshore.

2005 compared to 2004. For 2005, the increase in gross interest expense period-over-period is due to an increase in outstanding borrowings under our bank credit facility combined with an increase in average interest rates associated with our bank debt. Our average bank debt continued to increase from the second half of 2004 through the end of 2005 as we utilized our revolving facility to fund a portion of the asset exchange transaction with KeySpan in June 2004, two producing property acquisitions in September and October 2004 and two producing property acquisitions during 2005. Although the majority of our bank debt bore interest at LIBOR-based rates, average interest rates were affected by the eight rate increases by the Federal Reserve during 2005. Capitalized interest is a function of unevaluated properties, and the 5% increase during 2005 was primarily a function of the increase in our average borrowing rate as the balance of unevaluated properties declined during 2005.

Income Tax Provision. Our provision for taxes includes both state and federal taxes. During 2006, we recognized a taxable gain on the sale of our Gulf of Mexico assets of $264 million and utilized all of our net operating loss carryforwards to partially offset this taxable gain. The 25% decrease in income taxes in 2006 from 2005 corresponds to the 31% decrease in income before taxes. During 2006, income from operations was lower, primarily a result of the sale of our Gulf of Mexico assets. In addition, with the shift in our operations onshore, we incurred additional state taxes during 2006, including an increase of $5.4 million to provide for deferred taxes to the State of Texas under the newly enacted margin tax of 1% imposed on revenues less certain costs, as specified in the legislation enacted in May 2006.

The 35% decrease in income taxes for 2005 from 2004 corresponded to the 35% decrease in income before taxes. During 2005, revenues were lower and expenses were higher than in 2004. Our tax provision for 2005 included $1.4 million relating to nondeductible excess executive compensation expense incurred as a result of the contract renegotiation payment made to our Chief Executive Officer in February 2005 (see Consolidated Financial Statements, Note 6 Related Party Transactions *Employment Agreements*). In addition, the provision for 2005 includes additional expense of $2.0 million, primarily related to adjustments to estimates for federal and state liabilities incurred during the first quarter of 2005.

Liquidity and Capital Resources

Our principal requirements for capital are to fund our acquisition, exploration, and development activities and to satisfy our contractual obligations, including the repayment of debt and any amounts owing during the period relating to our derivative contracts. Our principal uses of capital related to our acquisition, exploration and development activities include the following:

§ Drilling and completing new natural gas and oil wells;

§ Constructing and installing new production infrastructure;

§ Acquiring additional reserves and producing properties;

§ Acquiring and maintaining our lease acreage position and our seismic resources;

§ Maintaining, repairing and enhancing existing natural gas and oil wells;

§ Plugging and abandoning depleted or uneconomic natural gas and oil wells; and

§ General and administrative costs directly associated with our acquisition, exploration and development activities, including payroll and other expenses attributable solely to our geological and geophysical employees.

To maintain the flexibility of our capital program, we typically do not enter into material long-term obligations with any of our drilling contractors or service providers with respect to our operated properties; however, we may choose to do so if we believe an opportunity is economically beneficial, as is the case with certain of our contracts for drilling rigs. See Consolidated Financial Statements, Note 9 Commitments and Contingencies *Drilling Contracts.*

Our capital expenditure budget for 2007 has been set at an initial level of $438 million. We continually evaluate our capital spending throughout the year. Actual spending levels may vary due to a variety of factors, including drilling results, natural gas prices, economic conditions, any future acquisitions, the outcome of our planned merger with Forest and the restrictions in the related merger agreement. Despite these possible variances, we believe that our operating cash flow and borrowings under our credit facility will be adequate to meet our capital and operating requirements over the next three-year period. In addition to utilizing operating cash flow and borrowings under our revolving credit facility, we believe we could finance capital expenditures with issuances of additional debt or equity securities and/or via development arrangements with industry partners. However, we are restricted by the pending merger agreement with Forest from incurring additional indebtedness outside the ordinary course of business and issuing additional equity or debt securities, among other things.

Sources of Liquidity and Capital Resources

Our primary sources of cash during 2006 were from funds generated from operations, bank borrowings and proceeds from the sale of substantially all of our Gulf of Mexico assets. We expect to fund our future capital expenditure programs, including any future acquisitions, as well as our contractual commitments, including any required settlement of derivative contracts, with our cash flows from operations and borrowings under our bank credit facility.

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Available Liquidity. The following table summarizes our total available liquidity at December 31, 2006 and December 31, 2005:

	December 31, 2006	December 31, 2005
	(in thousands)	
Available Liquidity:		
Revolving credit facility borrowing base	$ 500,000	$ 600,000
Outstanding borrowings		(422,000)
Letters of credit	(300)	(300)
Unused borrowing capacity	499,700	177,700
Cash and cash equivalents	53,950	7,979
Total available liquidity	$ 553,650	$ 185,679

At December 31, 2006, we had $499.7 million of available borrowing capacity under our revolving credit facility. This facility provides a lending commitment of $750 million with an additional $100 million available upon request and with prior approval from our lenders. Amounts available for borrowing under the credit facility are limited to a borrowing base, which was $500 million as of December 31, 2006. Cash and cash equivalents totaled $54.0 million and included funds released from designated cash in November 2006 following the expiration of the 180-day time period for reinvestment under Section 1031 of the remaining proceeds from the sale of our Louisiana offshore assets that were previously escrowed (see Consolidated Financial Statements, Note 1 Summary of Organization and Significant Accounting Policies *Cash Designated for Investment*). Although we had no outstanding indebtedness under our bank credit facility as of December 31, 2006 or as of the date of this Annual Report, consummation of the pending merger with Forest will require the refinancing or repayment of any outstanding indebtedness thereunder.

Cash Provided by Operating Activities. Net cash provided by operating activities decreased from $460.5 million during 2005 to $416.2 million during 2006. This 10% decrease was primarily due to commodity prices, production volumes, operating expenses and fluctuations in working capital caused by timing of cash receipts and disbursements. During 2006, we realized natural gas prices that were approximately 9% higher than natural gas prices realized during 2005, but experienced significantly lower production volumes during 2006, due primarily to the sale of our Gulf of Mexico assets, combined with continued hurricane-related curtailments from certain offshore Louisiana fields prior to their sale. The reduction in operating cash flow caused by these factors was offset in part by lower operating expenses resulting from the disposition of substantially all of our Gulf of Mexico assets as compared to 2005.

At December 31, 2006, we had working capital of $0.2 million. This small working capital balance is primarily a result of a current liability of $10.1 million relating to the fair market value of our open derivative contracts payable within the next 12-month period. Our working capital balance (or deficit) fluctuates as a result of the timing and amount of cash receipts and disbursements for operating activities, including payments required under our existing derivative contracts, and borrowings or repayments under our revolving credit facility. As a result, we often have a working capital deficit or a relatively small amount of positive working capital, which we believe is typical of companies of our size in the exploration and production industry.

Uses of Liquidity and Capital Resources

During 2006, our primary uses of cash were to fund exploration and development expenditures, repurchase common stock, repay bank borrowings and fund required payments under derivative instruments and other contractual obligations. In addition, during 2006, we made aggregate cash payments of $28.0 million for interest and $34.0 million for taxes. We received cash refunds of federal income taxes of $17.4 million.

Capital Expenditures. Total capital expenditures during 2006 were $615.1 million compared to $744.7 million spent in 2005. During 2006, we invested a net $612.8 million in natural gas and oil properties, and we spent $2.4 million for non-oil and gas property and equipment. Non-oil and gas property and equipment includes expenditures for the expansion and renovation of our Houston office lease space, and upgrades to our information technology systems and office equipment, and compares to $1.3 million spent during 2005. During 2006, we spent $516.8 million, or 84%, of our total natural gas and oil expenditures onshore and $71.3 million, or 12%, offshore with the balance of $24.7 million, or 4%, on capitalized interest and general and administrative costs. We completed the drilling of 363 gross wells (279.4 net), of which 91%, or 329 gross wells (253.3 net), were successful and 34 gross wells (26.1 net) were unsuccessful, with an additional 29 gross wells (18.8 net) in progress at December 31, 2006. All wells drilled during 2006 were drilled onshore, with the exception of three exploratory offshore wells in which we elected to participate. Of the three offshore wells drilled, two were successful (West Cameron 39 and 132), and one was unsuccessful (Eugene Island 357).

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The table below provides a five-year historical analysis of our capital expenditures for natural gas and oil properties and total net proved reserve additions, defined as the sum of reserve extensions and discoveries, revisions and acquisitions. See Consolidated Financial Statements, Note 12 Supplemental Information on Natural Gas and Oil Exploration, Development and Production Activities (unaudited) for a detailed calculation of the changes in our reserve quantities during the period.

	Years Ended December 31,				
	2006	**2005**	**2004**	**2003**	**2002**
	(in thousands)				
Natural gas and oil capital expenditures					
Producing property acquisitions [1]	$ 64,680	$ 197,680	$ 149,599	$ 175,420	$ 73,351
Leasehold and lease acquisition costs [2]	50,300	66,113	57,741	56,076	36,458
Development	426,615	366,902	245,971	162,235	122,036
Exploration	71,195	112,634	63,646	66,259	26,536
Total natural gas and oil capital expenditures	612,790	743,329	516,957	459,990	258,381
Producing property dispositions [3]	(719,234)	(1,864)	(72,712)		(5,309)
Net natural gas and oil capital expenditures	$ (106,444)	$ 741,465	$ 444,245	$ 459,990	$ 253,072
Proved reserve additions, net of revisions (MMcfe)	161,090	183,787	225,633	212,969	144,291

(1) For 2006, includes (i) East Texas producing properties acquired in April for a net $21.1 million; (ii) $21.0 million paid in August for a net profits interest to the predecessor owner of certain offshore properties acquired by us in October 2003,

which payment was accelerated by the sale of certain offshore Louisiana assets completed June 1, 2006; (iii) DJ Basin incremental working interests and producing properties acquired in December for a net $21.4 million; (iv) South Texas producing properties acquired in December for $4.3 million; (v) a final purchase price adjustment and return of capital of approximately $3.5 million, representing a reduction to the $159.0 million net purchase price paid for the South Texas properties acquired on November 30, 2005 from affiliates of Kerr-McGee; and (vi) $0.4 million for various other producing properties.

(2) For 2006, 2005, 2004, 2003 and 2002, leasehold

costs include capitalized interest and general and administrative expenses of $24.7 million, $25.7 million, $23.2 million, $20.2 million and $21.1 million, respectively.

(3) For 2006, dispositions include (i) net proceeds from the sale of our Louisiana Gulf of Mexico assets of $530.8 million, net of $4.4 million in fees associated with completion of the transaction and $4.4 million in purchase price adjustments; (ii) net proceeds from the sale of the Texas portion of our Gulf of Mexico assets of $190.8 million, net of $1.5 million in transaction fees; and (iii) $7.9 million in net proceeds for the sale of other assets.

For 2004, dispositions include (i) the

exchange of our Appalachian Basin assets for $60 million; plus (ii) the sale of our onshore South Louisiana assets for a net $13.1 million; less (iii) $0.4 million related to various other properties.

Debt Repayments. During 2006, we repaid all outstanding borrowings under our bank credit facility, reducing our bank debt by a net $422 million.

Stock Repurchases. On November 4, 2005, our Board of Directors approved discretionary repurchases from time to time over twelve months of up to $200 million in company stock in conjunction with the divesture of all of our Gulf of Mexico assets. During 2006, we repurchased 1,176,500 shares, or approximately 4%, of our outstanding common stock, in the open market for a total cost of approximately $61.6 million. All repurchases were paid for in cash and funded with cash on hand or borrowings under our revolving credit facility. All repurchased shares were retired. Future stock repurchases are prohibited by the pending merger agreement with Forest.

Future Commitments. The following table provides estimates of the timing of future payments that we were obligated to make based on agreements in existing as of December 31, 2006. At December 31, 2006, we did not have any capital leases and did not have any borrowings outstanding under our bank credit facility. The table includes references to our financial statements for information regarding the listed obligation.

The table below does not include any future commitments or contractual obligations related to our pending merger with Forest. The merger agreement contains certain termination rights for both us and Forest, including the right of either party to terminate the agreement if the merger is not consummated by September 30, 2007, and further provides that, upon termination of the merger agreement under specified circumstances, we may be required to pay to Forest a termination fee of $55 million, or Forest may be required to pay to us a termination fee of $60 million. In the event our stockholders do not adopt the merger agreement, we must pay to Forest a fee of $5 million to cover its expenses. In the event the stockholders of Forest do not approve the issuance of Forest common stock in the merger, Forest must pay us a fee of $5 million to cover our expenses. In addition, upon consummation of the pending merger, we estimate that we will be obligated to pay Lehman Brothers additional financial advisory fees of approximately $7.6 million, in addition to approximately $2.4 million paid as of the date of this Annual Report.

			Future Commitments Payments Due by Period (in thousands)			
	Reference	Total	1 year or less	2 3 years	4 5 years	after 5 years
Contractual Obligations:						
Principal 7% senior subordinated notes, due June 2013	Note 2	$ 175,000	$	$	$	$ 175,000
Interest 7% senior subordinated notes, due 2013	Note 2	79,625	12,250	24,500	24,500	18,375
Derivative instruments	Note 7	27,398	10,151	17,247		
Operating leases	Note 9	4,997	1,913	3,061	23	
Letters of credit	Note 9	300	300			
North Dakota lease option	Note 9	3,819	3,819			
Drilling contracts	Note 9	8,666	7,886	780		
Seismic contracts	Note 9	1,512	1,512			
		301,317	37,831	45,588	24,523	193,375
Other Long-Term Obligations:						
Asset retirement obligations	Note 1	72,782		451	191	72,140
Supplemental Executive Retirement Plan	Note 4	3,117	100	240	322	2,455
		75,899	100	691	513	74,595
Total Contractual Obligations and Commitments:		$ 377,216	$ 37,931	$ 46,279	$ 25,036	$ 267,970

Pursuant to the merger agreement, Forest will assume all of our outstanding indebtedness upon consummation of the pending merger, including the obligation triggered upon a change of control to offer to repurchase our 7% senior subordinated notes at a purchase price equal to 101% of the aggregate principal amount, plus accrued and unpaid interest and liquidated damages, if any. In addition, although we had no outstanding indebtedness under our bank credit facility as of December 31, 2006 or as of the date of this Annual Report, consummation of the pending merger will require the refinancing or repayment of any outstanding indebtedness thereunder. At December 31, 2006, our balance sheet reflects accrued interest payable on our senior subordinated notes of approximately $0.5 million.

Off-Balance Sheet Arrangements

Other than letters of credit issued under our bank credit facility, we do not currently utilize any off-balance sheet arrangements to enhance liquidity and capital resource positions, or for any other purpose.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Market Risk

Our major market risk exposure continues to be the prices applicable to our natural gas and oil production. The sales price of our production is primarily driven by the prevailing market price. Historically, prices received for our natural gas and oil production have been volatile and unpredictable.

Interest Rate Market Risk

At December 31, 2006, our total debt of $175 million was comprised entirely of debt under our senior subordinated notes which bear interest at a fixed interest rate of 7% per year. At December 31, 2006, we did not have outstanding borrowings under our bank credit facility, which borrowings bear interest at floating or market interest rates that are tied to the prime rate or LIBOR, at our option. Fluctuations in market interest rates will cause our annual interest costs to fluctuate. During 2006, the interest rate on our outstanding bank debt averaged 6.81% per year, and outstanding bank borrowings averaged $227,000. Hypothetically, if our average bank borrowings during 2006 were to remain constant over the next 12-month period, a 10% change in market interest rates would impact our cash flow by approximately $0.4 million per quarter.

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Commodity Price Risk

We utilize derivative commodity instruments to hedge future sales prices on a portion of our natural gas and oil production in an effort to achieve more predictable cash flows, as well as to reduce our exposure to adverse price fluctuations of natural gas. Our derivatives are not held for trading purposes. While the use of certain derivative instruments limits the downside risk of adverse price movements, it also limits increases in future revenues in the event of favorable price movements, as has been the case in recent years. In addition, because all of our open derivative contracts ceased to qualify for hedge accounting during the first quarter of 2006, our future earnings are expected to become more volatile as all subsequent changes in the fair market value of open contracts will be recognized as an increase or reduction to natural gas and oil revenues (see Consolidated Financial Statements, Note 1 Summary of Organization and Significant Accounting Policies *Derivative Instruments and Hedging Activities)*. We continue to evaluate opportunities to hedge both our production and basis differential exposure and may elect to do so if market conditions warrant.

The use of derivative instruments also involves the risk that the counterparties are unable to meet the financial terms of such transactions. Derivative instruments that we typically use include swaps, collars and options, which we generally place with investment grade financial institutions that we believe present minimal credit risks. We believe that our credit risk related to our natural gas derivative instruments is no greater than the risk associated with the underlying primary contracts and that the elimination of price risk reduces volatility in our reported results of operations, financial position and cash flows from period to period and lowers our overall business risk. However, as a result of our hedging activities, we may be exposed to greater credit risk in the future.

Changes in Fair Value of Derivative Instruments

The following table summarizes the change in the fair value of our derivative instruments for each of the twelve-month periods from January 1 to December 31, 2006 and 2005 and provides the fair value at the end of each period:

	Year Ended December 31,	
	2006	**2005**
Change in Fair Value of Derivatives Instruments:	Before Tax (in thousands)	
Fair value of contracts at January 1 (liability)	$ (417,658)	$ (75,149)
Realized loss on contracts settled [1]	69,208	265,236
Fair value of new contracts when entered into		
Increase (decrease) in fair value of all open contracts	321,052	(607,745)
Net increase (decrease) during period	390,260	(342,509)
Fair value of contracts outstanding at December 31 (liability)	$ (27,398)	$ (417,658)

(1) Includes $15.2 million paid during 2006 to liquidate and settle contracts. In June 2006, we paid $14.3 million to liquidate and settle contracts

covering 60,000 MMBtu per day for each of the months July through December 2006. This liquidation and settlement was made following the completion of the sale of substantially all of our Gulf of Mexico assets on June 1, 2006 and was required under the terms of our revolving credit facility. In August 2006, we elected to liquidate and settle open derivative contracts representing 20,000 MMBtu per day of hedged production for each of the months September and October 2006. The cost to liquidate and settle these contracts was approximately $0.9 million.

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Derivatives in Place as of the Date of Our Report

As of the date of this Annual Report, the following table summarizes, on an annual basis, our natural gas hedges in place for 2007 and 2008. For 2007, we have open derivative contracts covering approximately 41% of our estimated production volume. For 2008, we have open derivative contracts covering approximately 42% of our estimated production volume for the months of January and February 2008, and contracts covering 8% of estimated production for the remaining 10 months of 2008. All open derivative contracts will be accounted for using mark-to-market accounting, including those contracts entered into subsequent to December 31, 2006.

Year	Period (Months)	Transaction Type	Daily Volume (MMBtu/day)	HSC Basis ($/MMBtu)	NYMEX Floor Price ($/MMBtu)	NYMEX Ceiling Price ($/MMBtu)
2007	Jan Dec	Costless collar	20,000		$5.00	$6.50
2007	Jan Dec	Costless collar	10,000		5.00	6.79
2007	Mar Dec[1]	Costless collar	20,000		7.75	9.10
2007	Mar Dec[1]	Costless collar	10,000		7.75	9.12
2007	Mar Dec[1]	Costless collar	10,000		7.75	9.20
2007	Mar Dec[1]	Costless collar	20,000		7.75	9.25
2007	Mar Dec[1]	Costless collar	20,000		7.75	9.30
2007	Mar Dec[1]	Basis swap HSC	20,000	$0.2900		
2007	Mar Dec[1]	Basis swap HSC	20,000	$0.2925		
2007	Mar Dec[1]	Basis swap HSC	40,000	$0.3000		
2008	Jan Dec	Costless collar	20,000		$5.00	$5.72
2008	Jan Feb[1]	Costless collar	20,000		7.75	9.10
2008	Jan Feb[1]	Costless collar	10,000		7.75	9.12
2008	Jan Feb[1]	Costless collar	10,000		7.75	9.20
2008	Jan Feb[1]	Costless collar	20,000		7.75	9.25
2008	Jan Feb[1]	Costless collar	20,000		7.75	9.30
2008	Jan Feb[1]	Basis swap HSC	20,000	$0.2900		
2008	Jan Feb[1]	Basis swap HSC	20,000	$0.2925		
2008	Jan Feb[1]	Basis swap HSC	40,000	$0.3000		

(1) Transaction executed subsequent to December 31, 2006.

For natural gas, transactions are settled based upon the NYMEX price on the final trading day of the month.

With respect to any particular basis swap transaction, the counterparty is required to make a payment to us if the settlement price for any settlement period is greater than the swap price for the transaction, and we are required to make payment to the counterparty if the settlement price for any settlement period is less than the swap price for the transaction. For any particular collar transaction, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price for the transaction, and we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price for the transaction. We are not required to make or receive any payment in connection with a collar transaction if the settlement price is between the floor and the ceiling prices.

Item 8. Financial Statements and Supplemental Data

For financial statements required by Item 8, see Item 15 in Part IV of this Annual Report.

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

None.

Item 9A. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we conducted an evaluation of our disclosure controls and procedures, as this term is defined under Rule 13a-15(e) promulgated under the Exchange Act. Based on this evaluation, our Chief Executive Officer and our Chief

Financial Officer concluded that our disclosure controls and procedures were effective as of the end of the period covered by this Annual Report.

Design and Evaluation of Internal Control Over Financial Reporting

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, we have included a report of management s assessment of the design and effectiveness of its internal controls as part of this Annual Report on Form 10-K for the fiscal year ended December 31, 2006. Deloitte & Touche LLP, our registered public accounting firm, also attested to, and reported on, management s assessment of the effectiveness of internal control over financial reporting. Management s report and the independent registered public accounting firm s attestation report are included in our 2006 Financial Statements in Item 15 under the captions entitled Management s Report on Internal Control Over Financial Reporting and Report of Independent Registered Public Accounting Firm and are incorporated herein by reference.

Changes in Internal Control Over Financial Reporting

No change in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) occurred during the fourth quarter of our fiscal year ended December 31, 2006 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information.

None.

Part III.

Item 10. Directors and Executive Officers of Houston Exploration

Information regarding the Ethical Business Conduct Policy Statement and the Code of Ethics for Senior Financial Officers is described in the introductory pages of this Annual Report under the caption Available Information. The information required by Item 10 that relates to our directors and executive officers is incorporated by reference from the information appearing under the captions Election of Directors, Executive Management, Corporate Governance, Section 16(a) Beneficial Ownership Reporting and Compliance and Other Information in our definitive proxy statement or in an amendment to this Annual Report on Form 10-K/A that is to be filed with the SEC pursuant to the Exchange Act within 120 days of the end of our fiscal year on December 31, 2006.

Item 11. Executive Compensation

The information required by Item 11 that relates to compensation of our principal executive officers and our directors is incorporated by reference from the information appearing under the captions Compensation Discussion and Analysis and Director Compensation in our definitive proxy statement or in an amendment to this Annual Report on Form 10-K/A that is to be filed with the SEC within 120 days of the end of our fiscal year on December 31, 2006. In addition and in accordance with Item 402(a)(8) of Regulation S-K, the information contained in our definitive proxy statement or a Form 10-K/A under the subheading Report of the Compensation and Management Development Committee of the Board of Directors shall not be deemed to be filed as part of, or incorporated by reference into, this Annual Report. For information concerning our code of ethics, see Item 1. and 2. Business and Properties Available Information.

Item 12. Security Ownership of Beneficial Owners and Management

The information required by Item 12 that relates to the ownership of securities by management and others is incorporated by reference from the information appearing under the caption Security Ownership in our definitive proxy statement or in an amendment to this Annual Report on Form 10-K/A that is to be filed with the SEC within 120 days of the end of our fiscal year on December 31, 2006.

Item 13. Certain Relationships and Related Transactions

The information required by Item 13 that relates to business relationships and transactions with our management and other related parties is incorporated by reference from the information appearing under the captions Related Party Transactions, Transactions Between the Company and Managements and Compensation Committee Interlocks and Insider Participation in our definitive proxy statement or in an amendment to this Annual Report on Form 10-K/A that is to be filed with the SEC within 120 days of the end of our fiscal year on December 31, 2006.

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Item 14. Principal Accounting Fees and Services

The information required by Item 14 that relates to services provided by our registered public accounting firm and the fees incurred for services provided during 2005 and 2004 is incorporated by reference from the information appearing under the captions Fees Billed by Independent Public Accountants in our definitive proxy statement or in an amendment to this Annual Report on Form 10-K/A that is to be filed with the SEC within 120 days of the end of our fiscal year on December 31, 2006.

Part IV.

Item 15. Exhibits, Financial Statement Schedules

(a) Documents Filed as a Part of this Report

1. Financial Statements:

All other schedules are omitted because they are not applicable, not required, or because the required information is included in the financial statements or related notes.

2. Exhibits:

INDEX TO EXHIBITS

EXHIBITS	DESCRIPTION
2.1	Agreement and Plan of Merger dated as of January 7, 2007 by and among the Company, Forest Oil Corporation and MJCO Corporation (filed as exhibit 2.1 to our Current Report on Form 8-K dated January 7, 2007 (file No. 001-11899) and incorporated by reference herein).
3.1	Restated Certificate of Incorporation, as amended, including the Certificate of Amendment thereto dated April 26, 2005 (filed as exhibit 3.1 to our Quarterly Report on Form 10-Q for the period ended March 31, 2005 (file No. 001-11899) and incorporated by reference herein).
3.2	Restated Bylaws of The Houston Exploration Company (filed as Exhibit 3.2 to our Annual Report on Form 10-K for the year ended December 31, 2005 (File No.001-11899) and incorporated by reference).
4.1	Indenture, dated as of June 10, 2003, between The Houston Exploration Company and the Bank of New York, as Trustee, with respect to the 7% Senior Subordinated Notes due 2013 (filed as Exhibit 4.2 to our Registration Statement on Form S-4 (Registration No. 333-106836) and incorporated by reference).
4.2	Rights Agreement, dated as of August 12, 2004, between The Houston Exploration Company and The Bank of New York, as Rights Agent (filed as Exhibit 4.1 to our Current Report on Form 8-K

	dated August 13, 2004 (File No. 001-11899) and incorporated by reference).
4.3	First Amendment dated as of May 2, 2005, to the Rights Agreement dated as of August 12, 2004 between The Houston Exploration Company and The Bank of New York, as Rights Agent (filed as exhibit 4.1 to

EXHIBITS	DESCRIPTION
	our Quarterly Report on Form 10-Q for the period ended March 31, 2005 (file No. 001-11899) and incorporated by reference herein).
4.4	Second Amendment to Rights Agreement dated as of January 7, 2007 between The Houston Exploration Company and The Bank of New York, as Rights Agent (filed as exhibit 4.1 to our Current Report on Form 8-K dated January 7, 2007 (file No. 001-11899) and incorporated by reference herein).
4.5	Form of Certificate of Designation of Series A Junior Participating Preferred Stock of The Houston Exploration Company (filed as Exhibit 4.2 to our Current Report on Form 8-K dated August 13, 2004 (File No. 001-11899) and incorporated by reference).
10.1	Amended and Restated Credit Agreement dated November 30, 2005 among The Houston Exploration Company and Wachovia Bank, National Association, as Issuing Bank and Administrative Agent; The Bank of Nova Scotia and Bank of America as Co-Syndication Agents; and BNP Paribas and Comerica Bank as Co-Documentation Agents (filed as exhibit 99.1 to our Current Report on Form 8-K dated November 30, 2005 (File No. 001-11899) and incorporated by reference).
10.2	First Amendment to Amended and Restated Credit Agreement effective May 31, 2006 among The Houston Exploration Company and Wachovia Bank, National Association, as Issuing Bank and Administrative Agent; The Bank of Nova Scotia and Bank of America as Co-Syndication Agents; and BNP Paribas and Comerica Bank as Co-Documentation Agents (filed as Exhibit 10.1 to our Quarterly Report on Form 10-Q for the period ended June 30, 2006 (File No. 001-11899) and incorporated by reference).
10.3	Purchase and Sale Agreement, dated September 3, 2003, by and among Transworld Exploration and Production, Inc., as Seller, and The Houston Exploration Company, as Buyer (filed as Exhibit 2.1 to our Current Report on Form 8-K dated October 15, 2003 (file No. 001-11899) and incorporated by reference).
10.4	Asset Contribution Agreement dated June 2, 2004 between The Houston Exploration Company and Seneca-Upshur Petroleum, Inc. (filed as Exhibit 99.3 to our Current Report on Form 8-K dated June 30, 2004 (File No. 001-11899) and incorporated by reference).
10.5	Tax Matters Agreement dated as of June 2, 2004 by and among The Houston Exploration Company, Seneca-Upshur Petroleum, Inc., THEC Holdings Corp., and KeySpan Corporation (filed as Exhibit 99.4 to our Current Report on Form 8-K dated June 30, 2004 (File No. 001-11899) and incorporated by reference).
10.6	Distribution Agreement dated as of June 2, 2004 by and among The Houston Exploration Company, Seneca-Upshur Petroleum, Inc., THEC Holdings Corp. and KeySpan Corporation (filed as Exhibit 99.2 to our Current Report on Form 8-K dated June 30, 2004 (File No. 001-11899) and incorporated by reference).
10.7	Purchase and Sale Agreement, dated September 17, 2004, between The Houston Exploration Company and Orca Energy, L.P. (filed as Exhibit 2.1 to our Current Report on Form 8-K dated

	November 1, 2004 (File No. 001-11899) and incorporated by reference).
10.8	Purchase and Sale Agreement dated October 21, 2005 by and between Kerr-McGee Oil & Gas Onshore LP D/B/A KMOG Onshore LP and Westport Oil and Gas Company, L.P., as sellers, and The Houston Exploration Company, as buyer, (filed as exhibit 99.2 to our Current Report on Form 8-K dated November 30, 2005 (File No. 001-11899) and incorporated by reference).
10.9	Purchase and Sale Agreement dated February 28, 2006 between The Houston Exploration Company, as seller, and Merit Management Partners I, L.P., Merit Management Partners II, L.P., Merit Management Partners III, L.P., Merit Energy Partners III, L.P., Merit Energy Partners D-III, L.P., Merit Energy Partners E-III, L.P. and Merit Energy Partners F-III, L.P., collectively, as buyer (filed as Exhibit 10.1 to our Quarterly Report on Form 10-Q for the period ended March 31, 2006 (File No. 001-11899) and incorporated by reference).

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EXHIBITS	DESCRIPTION
10.10	Purchase and Sale Agreement dated April 7, 2006 between The Houston Exploration Company, as seller, and Merit Management Partners I, L.P., Merit Management Partners II, L.P., Merit Management Partners III, L.P., Merit Energy Partners III, L.P., Merit Energy Partners D-III, L.P., Merit Energy Partners E-III, L.P. and Merit Energy Partners F-III, L.P., collectively, as buyer (filed as Exhibit 99.1 to our Current Report on Form 8-K dated June 2, 2006 (File No. 001-11899) and incorporated by reference).
10.11(2)	Deferred Compensation Plan for Non-Employee Directors (filed as Exhibit 10.24 to our Annual Report on Form 10-K for the year ended December 31, 1997 (File No. 001-11899) and incorporated by reference).
10.12(2)	Amendment dated April 26, 2005, but effective as of December 31, 2004, to The Houston Exploration Company Non-Employee Director Deferred Compensation Plan (filed as Exhibit 10.4 to our Current Report on Form 8-K dated July 31, 2006 (File No. 001-11899) and incorporated by reference).
10.13(2)	The Houston Exploration Company Post-2004, AJCA Compliant Deferred Compensation Plan for Non-Employee Directors dated April 26, 2005, effective as of January 1, 2005 (filed as Exhibit 10.5 to our Current Report on Form 8-K dated July 31, 2006 (File No. 001-11899) and incorporated by reference).
10.14(2)	Compensation Table for Non-Employee Directors, effective January 1, 2006 (filed as exhibit 99.2 to our Current Report on Form 8-K dated January 6, 2006.
10.15(2)	Amended and Restated 1996 Stock Option Plan (filed as Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 1998 (File No. 001-11899) and incorporated by reference).
10.16(2)	1999 Non-Qualified Stock Option Plan dated October 26, 1999 (filed as Exhibit 10.24 to our Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 001-11899) and incorporated by reference).
10.17(2)	Amended and Restated 2002 Long-Term Incentive Plan effective May 17, 2002, adopted October 26, 2003 (filed as Exhibit 10.31 to our Annual Report on Form 10-K for the year ended December 31, 2003 (file No. 001-11899) and incorporated by reference).
10.18(2)	Amended and Restated 2004 Long Term Incentive Plan (filed as exhibit 99.1 to our Current Report on Form 8-K dated January 31, 2006 (File No. 001-11899) and incorporated by reference).
10.19(2)	Supplemental Executive Pension Plan dated May 1, 1996 (filed as exhibit 10.23 to our Registration Statement on Form S-1/A (Amendment No. 2) (Registration No. 333-4437) and incorporated by reference).
10.20(2)	The Houston Exploration Company Supplemental Executive Retirement Plan (Amended and Restated on July 25, 2006) (filed as Exhibit 10.1 to our Current Report on Form 8-K dated July 31, 2006 (File No. 001-11899) and incorporated by reference).

10.21[2]	First Amendment to The Houston Exploration Company Supplemental Executive Retirement Plan (filed as exhibit 10.3 to our Current Report on Form 8-K dated January 7, 2007 (file No. 001-11899) and incorporated by reference herein).
10.22[2]	Executive Deferred Compensation Plan dated January 1, 2002 (filed as Exhibit 10.28 to our Annual Report on Form 10-K for the year ended December 31, 2002 (File No. 001-11899) and incorporated by reference).
10.23[2]	Amendment [No. 1] to The Houston Exploration Company Executive Deferred Compensation Plan (filed as exhibit 99.2 to our Current Report on Form 8-K dated January 31, 2006 (File No. 001-11899) and incorporated by reference).
10.24[2]	Amendment No. 2 dated July 25, 2006, but effective as of December 31, 2004, to The Houston Exploration Company Executive Deferred Compensation Plan (filed as Exhibit 10.2 to our Current Report on Form 8-K dated July 31, 2006 (File No. 001-11899) and incorporated by reference).

EXHIBITS	DESCRIPTION
10.25[2]	The Houston Exploration Company 2005 Executive Deferred Compensation Plan (filed as Exhibit 10.3 to our Current Report on Form 8-K dated July 31, 2006 (File No. 001-11899) and incorporated by reference).
10.26[2]	Amended and Restated Employment Agreement dated February 8, 2005 between The Houston Exploration Company and William G. Hargett (filed as Exhibit 10.1 to our Current Report on Form 8-K dated February 8, 2005 (File No. 001-11899) and incorporated by reference).
10.27[2]	Amendment No. 1, dated October 24, 2006, to the Amended and Restated Employment Agreement dated February 8, 2005 between The Houston Exploration Company and William G. Hargett (filed as Exhibit 10.1 to our Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.38[2]	Amended and Restated Employment Agreement between The Houston Exploration Company and Steven L. Mueller dated February 8, 2005 (filed as Exhibit 10.19 to our Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 001-11899) and incorporated by reference).
10.29[2]	Amendment No. 1, dated October 24, 2006, to the Amended and Restated Employment Agreement dated February 8, 2005 between The Houston Exploration Company and Steven L. Mueller (filed as Exhibit 10.2 to our Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.30[2]	Amended and Restated Employment Agreement between The Houston Exploration Company and John H. Karnes dated February 8, 2005 (filed as Exhibit 10.20 to our Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 001-11899) and incorporated by reference).
10.31[2]	Separation Agreement and General Release dated December 8, 2005 between The Houston Exploration Company and John H. Karnes (filed as exhibit 99.1 to our Current Report on Form 8-K dated December 12, 2005 (File No. 001-11899) and incorporated by reference).
10.32[2]	Amended and Restated Employment Agreement between The Houston Exploration Company and James F. Westmoreland dated February 8, 2005 (filed as Exhibit 10.21 to our Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 001-11899) and incorporated by reference).
10.33[2]	Amendment No. 1, dated October 24, 2006, to the Amended and Restated Employment Agreement dated February 8, 2005 between The Houston Exploration Company and James F. Westmoreland (filed as Exhibit 10.7 to our Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.34[2]	Amended and Restated Employment Agreement between The Houston Exploration Company and Roger B. Rice dated February 8, 2005 (filed as Exhibit 10.22 to our Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 001-11899) and incorporated by reference).
10.35[2]	

	Amendment No. 1, dated October 24, 2006, to the Amended and Restated Employment Agreement dated February 8, 2005 between The Houston Exploration Company and Roger B. Rice (filed as Exhibit 10.5 to our Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.36[(2)]	Employment Agreement dated February 10, 2005 between The Houston Exploration Company and Joanne C. Hresko (filed as Exhibit 10.3 to our Current Report on Form 8-K dated February 8, 2005 (File No. 001-11899) and incorporated by reference).
10.37[(2)]	Amendment No. 1, dated October 24, 2006, to the Employment Agreement dated February 10, 2005, between The Houston Exploration Company and Joanne C. Hresko (filed as Exhibit 10.8 to our Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.38[(2)]	Employment Agreement effective March 10, 2005, between The Houston Exploration Company and John E. Bergeron, Jr. (filed as exhibit 99.2 to our Current Report on Form 8-K dated March 10, 2005 (File No. 001-11899) and incorporated by reference).

EXHIBITS	DESCRIPTION
10.39(2)	Amendment No. 1, dated October 24, 2006, to the Employment Agreement dated March 10, 2005, between The Houston Exploration Company and John E. Bergeron, Jr. (filed as Exhibit 10.9 to our Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.40(2)	Employment Agreement effective April 13, 2005, between The Houston Exploration Company and Jeffrey B. Sherrick (filed as exhibit 99.2 to our Current Report on Form 8-K dated April 13, 2005 (File No. 001-11899) and incorporated by reference).
10.41(2)	Amendment No. 1, dated October 24, 2006, to the Employment Agreement dated April 13, 2005, between The Houston Exploration Company and Jeffrey B. Sherrick (filed as Exhibit 10.6 to our Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.42(2)	Employment Agreement dated January 18, 2006 between The Houston Exploration Company and Robert T. Ray (filed as exhibit 99.1 to our Current Report on Form 8-K dated January 18, 2006 (File No. 001-11899) and incorporated by reference).
10.43(2)	Amendment No. 1, dated October 24, 2006, to the Employment Agreement dated January 18, 2006, between The Houston Exploration Company and Robert T. Ray (filed as Exhibit 10.3 to our Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.44(2)	Employment Agreement dated March 27, 2006 between The Houston Exploration Company and Carolyn M. Campbell (filed as Exhibit 99.1 to our Current Report on Form 8-K dated March 27, 2006 (File No. 001-11899) and incorporated by reference).
10.45(2)	Amendment No. 1, dated October 24, 2006, to the Employment Agreement dated March 27, 2006, between The Houston Exploration Company and Carolyn M. Campbell (filed as Exhibit 10.4 to our Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.46	Form of Amendment No. 2 to [Amended and Restated] Employment Agreement entered into by and between The Houston Exploration Company and each of William G. Hargett, Steven L. Mueller, James F. Westmoreland, Roger B. Rice, Joanne C. Hresko, John E. Bergeron Jr., Jeffrey B. Sherrick, Robert T. Ray and Carolyn M. Campbell (filed as Exhibit 10.1 to our Current Report on Form 8-K dated January 7, 2007 (file No. 001-11899) and incorporated by reference herein).
10.47(2)	Change of Control Plan dated October 26, 1999 (filed as Exhibit 10.25 to our Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 001-11899) and incorporated by reference).
10.48(1)(2)	First Amendment to The Houston Exploration Company Change of Control Plan dated May 17, 2002.
10.49(2)	Second Amendment to The Houston Exploration Company Change of Control Plan (filed as exhibit 10.4 to our Current Report on Form 8-K dated January 7, 2007 (file No. 001-11899) and

	incorporated by reference herein).
10.50[2]	Form of Indemnification Agreement for Directors and Executive Officers (filed as Exhibit 10.8 to our Quarterly Report on Form 10-Q for the period ended June 30, 2006 (File No. 001-11899) and incorporated by reference).
10.51[2]	Form of Non-Qualified Stock Option Agreement (filed as Exhibit 10.9 to our Quarterly Report on Form 10-Q for the period ended June 30, 2006 (File No. 001-11899) and incorporated by reference).
10.52[2]	Form of Director Restricted Stock Award Agreement (filed as Exhibit 10.10 to our Quarterly Report on Form 10-Q for the period ended June 30, 2006 (File No. 001-11899) and incorporated by reference).
10.53[2]	Form of Employee Restricted Stock Award Agreement (filed as Exhibit 10.11 to our Quarterly Report on Form 10-Q for the period ended June 30, 2006 (File No. 001-11899) and incorporated by reference).
12.1[1]	Computation of ratio of earnings to fixed charges.

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EXHIBITS	DESCRIPTION
21.1[(1)]	Subsidiaries of The Houston Exploration Company.
23.1[(1)]	Consent of Deloitte & Touche LLP.
23.2[(1)]	Consent of Netherland, Sewell & Associates.
23.3[(1)]	Consent of Miller and Lents.
31.1[(1)]	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2[(1)]	Certification of Robert T. Ray, Chief Financial Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1[(1)]	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2[(1)]	Certification of Robert T. Ray, Chief Financial Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(1) Filed herewith.

(2) Management contract or compensation plan.

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SIGNATURES

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

THE HOUSTON EXPLORATION COMPANY

By: /s/ William G. Hargett
William G. Hargett
President and Chief Executive Officer

Date: February 28, 2007

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POWER OF ATTORNEY

Each person whose signature appears below hereby constitutes and appoints Robert T. Ray and James F. Westmoreland, and each of them, his true and lawful attorney-in-fact and agent, with full powers of substitution, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report of Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission granting to said attorneys-in-fact, and each of them, full power and authority to perform any other act on behalf of the undersigned required to be done in connection therewith.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant in the capacities and on the dates indicated.

Signature	Title	Date
/s/ William G. Hargett William G. Hargett	Chairman of the Board of Directors, President and Chief Executive Officer (Principal Executive Officer)	February 28, 2007
/s/ Robert T. Ray Robert T. Ray	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 28, 2007
/s/ James F. Westmoreland James F. Westmoreland	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 28, 2007
/s/ Robert B. Catell Robert B. Catell	Director	February 28, 2007
/s/ John U. Clarke John U. Clarke	Director	February 28, 2007
/s/ David G. Elkins David G. Elkins	Director	February 28, 2007
/s/ Harold R. Logan, Jr. Harold R. Logan, Jr.	Director	February 28, 2007
/s/ Thomas A. McKeever Thomas A. McKeever	Director	February 28, 2007
/s/ Stephen W. McKessy Stephen W. McKessy	Director	February 28, 2007

/s/ Donald C. Vaughn	Director	February 28, 2007
Donald C. Vaughn		

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Glossary of Oil and Gas Terms

The definitions set forth below apply to the indicated terms as used in this Annual Report on Form 10-K. All volumes of natural gas referred to are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit and in most instances are rounded to the nearest major multiple.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to crude oil or other liquid hydrocarbons.

Bbl/d. One barrel per day.

Bcf. Billion cubic feet.

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.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

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

Developed acreage. The number of acres allocated or assignable to producing wells or wells capable of production.

Developed well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

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

Equivalents. When we refer to equivalents, we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one barrel of oil is equal to six thousand cubic feet of natural gas.

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

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature 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.

Intangible Drilling and Development Costs. Expenditures made by an operator for wages, fuel, repairs, hauling, supplies, surveying, geological works etc., incident to and necessary for the preparing for and drilling of wells and the construction of production facilities and pipelines.

Lease Operating Expense. Recurring expenses incurred to operate wells and equipment on a producing lease. Examples include pumping and gauging, chemicals, compression, fuel and water, insurance and property taxes.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

MBbls/d. One thousand barrels of crude oil or other liquid hydrocarbons per day.

Mcf. One thousand cubic feet.

Mcf/d. One thousand cubic feet per day.

Mcfe. One 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.

Mcfe/d. One 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, per day.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMbtu. One million Btus.

MMMbtu. One billion Btus.

MMcf. One million cubic feet.

MMcf/d. One million cubic feet per day.

MMcfe. One 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 gross wells.

Net revenue interest. An interest in the production and revenues created from the working interest which is generally calculated net or after deducting any royalty interests.

Oil. Crude oil and condensate.

Present value or PV10. When used with respect to natural gas and oil reserves, the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date indicated, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%.

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

Proved developed nonproducing 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 able to produce to market.

Proved reserves. The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. In addition, please refer to the definitions of proved oil and gas reserves as provided in Rule 4-10(a)(2)(3)(4) of Regulation S-X of the federal securities laws. The rule is available at the SEC web site, http://www.sec.gov/divisions/corpfin/forms/regsx.htm#gas.

Proved undeveloped location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

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 from recompletion.

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

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

Royalty interest. An interest in a natural gas and oil property entitling the owner to a share of natural gas or oil production free of costs of production.

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Tangible Drilling and Development Costs. The costs of physical lease and well equipment and structures and the costs of assets that themselves have a salvage value.

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 natural gas and oil, regardless of whether the acreage contains proved reserves.

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

Workover. Operations on a producing well to restore or increase production.

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MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Board of Directors and Stockholders of
The Houston Exploration Company

The Houston Exploration Company s management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of management, including Houston Exploration s principal executive officer and principal financial officer, Houston Exploration conducted an evaluation of the effectiveness of internal control over financial reporting based on the framework in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on Houston Exploration s evaluation under the framework in *Internal Control Integrated Framework*, our principal executive officer and principal financial officer concluded that internal control over financial reporting was effective as of December 31, 2006. The conclusion of our principal executive officer and principal financial officer is based on the recognition that there are inherent limitations in all systems of internal control. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the polices or procedures may deteriorate. Management s assessment of the effectiveness of internal control over financial reporting as of December 31, 2006 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein.

The Houston Exploration Company
Houston, Texas
February 28, 2007

/s/ William G. Hargett	/s/ Robert T. Ray
William G. Hargett Chairman, President and Chief Executive Officer	Robert T. Ray Senior Vice President and Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
The Houston Exploration Company
Houston, Texas

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

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

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

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of The Houston Exploration Company and subsidiaries as of December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, management s assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As discussed in Note 1 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 123(R), Share-Based Payment on January 1, 2006 and SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans On December 31, 2006.

DELOITTE & TOUCHE LLP
Houston, Texas
February 28, 2007

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THE HOUSTON EXPLORATION COMPANY
CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

	December 31, 2006	December 31, 2005
Assets:		
Cash and cash equivalents	$ 53,950	$ 7,979
Accounts receivable	86,416	146,020
Inventories	2,900	2,726
Deferred tax asset	10,244	145,922
Prepayments and other	8,370	19,709
Total current assets	161,880	322,356
Natural gas and oil properties, full cost method		
Unevaluated properties	28,317	107,146
Properties subject to amortization	3,478,878	3,556,755
Other property and equipment	15,101	12,971
	3,522,296	3,676,872
Less: Accumulated depreciation, depletion and amortization	1,930,964	1,658,532
	1,591,332	2,018,340
Other non-current assets	18,514	20,928
Total Assets	$ 1,771,726	$ 2,361,624
Liabilities:		
Accounts payable and accrued expenses	$ 151,482	$ 177,159
Derivative financial instruments	10,151	352,457
Asset retirement obligation		7,265
Total current liabilities	161,633	536,881
Long-term debt and notes	175,000	597,000
Derivative financial instruments	17,247	65,201
Deferred federal income taxes	363,322	341,302
Asset retirement obligation	72,782	112,406
Other non-current liabilities	17,138	15,696
Total Liabilities	807,122	1,668,486

Commitments and Contingencies (see Note 9)

Stockholders Equity:		
Preferred Stock, $0.01 par value, 5,000,000 shares authorized and no shares issued		
Common Stock, $0.01 par value, 100,000,000 shares authorized and 28,098,172 and 28,980,128 shares issued and outstanding at December 31, 2006 and 2005, respectively	281	289
Additional paid-in capital	253,922	297,218
Retained earnings	731,150	663,367
Accumulated other comprehensive (loss)	(20,749)	(267,736)
Total Stockholders Equity	964,604	693,138
Total Liabilities and Stockholders Equity	$ 1,771,726	$ 2,361,624

The accompanying notes are an integral part of these consolidated financial statements.

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THE HOUSTON EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except share data)

	For the Years Ended December 31,		
	2006	2005	2004
Revenues:			
Natural gas and oil revenues	$ 529,586	$ 620,271	$ 649,087
Other	2,011	1,272	1,352
Total revenues	531,597	621,543	650,439
Operating expenses:			
Lease operating	63,959	67,796	55,925
Severance tax	18,102	18,121	11,933
Transportation expense	10,636	11,883	11,819
Asset retirement accretion expense	3,373	5,278	4,902
Depreciation, depletion and amortization	253,666	295,351	265,148
Writedown in carrying value of natural gas and oil properties	19,000		
General and administrative, net of amounts capitalized	36,013	38,378	32,899
Total operating expenses	404,749	436,807	382,626
Income from operations	126,848	184,736	267,813
Other (income) expense	(13,495)	142	(1,058)
Interest expense, net of amounts capitalized	25,206	16,535	9,455
Income before income taxes	115,137	168,059	259,416
Provision for income taxes	47,354	62,890	96,592
Net income	$ 67,783	$ 105,169	$ 162,824
Earnings per share:			
Net income per share basic	$ 2.37	$ 3.66	$ 5.50
Net income per share diluted	$ 2.36	$ 3.62	$ 5.44
Weighted average shares outstanding basic	28,543	28,707	29,616
Weighted average shares outstanding diluted	28,693	29,037	29,932

The accompanying notes are an integral part of these consolidated financial statements.

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THE HOUSTON EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
AND COMPREHENSIVE INCOME (LOSS)
(in thousands, except share data)

	Common Stock		Additional Paid-In	Retained	Accumulated Other Comprehensive Income	Total Shareholders
	Shares	$ Value	Capital	Earnings	(Loss)	Equity
Balance January 1, 2004	**31,437,581**	**$ 315**	**$ 365,973**	**$ 395,374**	**$ (26,128)**	**$ 735,534**
Common shares issued stock options	873,626	9	25,586			25,595
Common shares issued restricted stock	49,000		-			-
Common shares issued public offering	6,820,000	68	310,659			310,727
Common shares repurchased from KeySpan and retired	(10,800,000)	(108)	(441,471)			(441,579)
Amortization of restricted stock			1,126			1,126
Stock compensation expense			3,670			3,670
Tax benefit non-qualified stock options			4,922			4,922
Comprehensive income:						
Net income				162,824		162,824
Other comprehensive income (loss)						
Derivative settlements reclassified to income, net of tax of $24,141					44,054	44,054
Unrealized loss change in fair value of derivatives, net of tax of $42,529					(63,953)	(63,953)
Total comprehensive income						142,925

Balance December 31, 2004	**28,380,207**	**$ 284**	**$ 270,465**	**$ 558,198**	**$ (46,027)**	**$ 782,920**
Common shares issued stock options	510,316	5	16,285			16,290
Common shares issued restricted stock	89,605		-			-
Amortization of restricted stock			2,882			2,882
Stock compensation expense			4,229			4,229
Tax adjustment to 2004 benefit from non-qualified stock options			(180)			(180)
Tax benefit non-qualified stock options			3,537			3,537
Comprehensive income:						
Net income				105,169		105,169
Other comprehensive income (loss)						
Derivative settlements reclassified to income, net of tax of $93,894					171,342	171,342
Unrealized loss change in fair value of derivatives, net of tax of $214,694					(393,051)	(393,051)
Total comprehensive (loss)						(116,540)
Balance December 31, 2005	**28,980,128**	**$ 289**	**$ 297,218**	**$ 663,367**	**$ (267,736)**	**$ 693,138**
Common shares issued stock options	214,868	3	7,497			7,500
Common shares issued restricted stock and units	79,676	1	(1)			-
Common shares repurchased and retired	(1,176,500)	(12)	(61,626)			(61,638)
Amortization of restricted stock			3,939			3,939
			5,783			5,783

Stock compensation expense						
Tax benefit non-qualified stock options			1,112			1,112
Comprehensive income:						
Net income				67,783		67,783
Other comprehensive income (loss)						
Derivative settlements reclassified to income, net of tax of $24,500					44,708	44,708
Unrealized gain change in fair value of derivatives, net of tax of $116,524					204,528	204,528
Unfunded future post retirement benefit obligation, net of tax of $1,271					(2,249)	(2,249)
Total comprehensive income						314,770
Balance December 31, 2006	**28,098,172**	**$ 281**	**$ 253,922**	**$ 731,150**	**$ (20,749)**	**$ 964,604**

The accompanying notes are an integral part of these consolidated financial statements.

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THE HOUSTON EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Years Ended December 31,		
	2006	**2005**	**2004**
Operating Activities:			
Net income	$ 67,783	$ 105,169	$ 162,824
Adjustments to reconcile net income to net cash provided by operating activities:			
Deferred income tax expense	22,702	57,555	50,500
Depreciation, depletion and amortization	253,666	295,351	265,148
Writedown in carrying value of natural gas and oil properties	19,000		
Asset retirement accretion expense	3,373	5,278	4,902
Stock compensation expense	9,722	7,111	4,796
Tax benefit (loss) non-qualified stock options		(180)	4,922
Unrealized (gain) loss on derivative instruments	(4,757)	(694)	1,950
Amortization of premiums paid on derivative contracts			5,287
Debt extinguishment expense	572		211
Changes in operating assets and liabilities:			
Accounts receivable	59,604	(42,951)	(8,387)
Inventories	(174)	(1,750)	95
Prepayments and other	11,339	(11,714)	(3,289)
Other assets	2,041	(43)	(6,218)
Accounts payable and accrued expenses	(25,108)	42,403	39,693
Other non-current liabilities	(3,574)	4,974	7,276
ARO liability for assets abandoned			(2,569)
Net cash provided by operating activities	416,189	460,509	527,141
Investing Activities:			
Investment in property and equipment	(614,228)	(728,882)	(523,205)
Cash designated for investment	(323,675)		
Withdrawal of cash designated for investment	323,675		
Dispositions and other	719,235	1,879	13,283
Net cash provided by (used in) investing activities	105,007	(727,003)	(509,922)
Financing Activities:			
Proceeds from long-term borrowings	525,000	831,000	420,000
Repayments of long-term borrowings	(947,000)	(589,000)	(367,000)
Debt issuance costs	(199)	(2,394)	(1,555)
Proceeds from issuance of common stock from exercise of stock options	7,500	16,290	25,596
Tax benefit non-qualified stock options	1,112		
Proceeds from issuance of common stock			310,727
Repurchase of common stock	(61,638)		(388,979)

Net cash provided by (used in) financing activities		(475,225)		255,896		(1,211)
Increase (decrease) in cash and cash equivalents		45,971		(10,598)		16,008
Cash and cash equivalents, beginning of year		7,979		18,577		2,569
Cash and cash equivalents, end of year	$	53,950	$	7,979	$	18,577
Supplemental Information:						
Non-cash transactions:						
Change in investments in property and equipment accrued, not paid	$	(927)	$	(15,785)	$	4,705
Divesture and exchange of Appalachian Basin assets						60,000
Deferred tax benefit exchange of Appalachian Basin assets						7,400
Cash paid during period for:						
Interest	$	28,015	$	23,858	$	16,385
Federal and state income taxes, net payments and refunds		16,635		19,297		41,854

The accompanying notes are an integral part of these consolidated financial statements.

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THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 Summary of Organization and Significant Accounting Policies (Reserve quantities, wells, acreage and working interests included below are unaudited.)

Our Business

We are an independent natural gas and oil producer engaged in the exploration, development, exploitation and acquisition of natural gas and oil reserves in North America. We were founded in December 1985 as a Delaware corporation and completed our initial public offering in September 1996. As of December 31, 2006, our operations were concentrated in four producing regions within the United States: South Texas; the Arkoma Basin of Arkansas and Oklahoma; East Texas; and the Uinta and DJ Basins of the Rocky Mountains.

Our total net proved reserves as of December 31, 2006 were 699 billion cubic feet equivalent, or Bcfe. All of our reserves are estimated on an annual basis by independent petroleum engineers. Approximately 67% of our proved reserves at December 31, 2006, were classified as proved developed. During 2006, we produced 88.2 Bcfe. Production volumes during 2006 were significantly impacted by the sale of substantially all of our Gulf of Mexico assets during the first and second quarters of 2006 and continued curtailments of certain of these offshore fields prior to their sale primarily as a result of infrastructure damage to third party pipelines and processing facilities caused by Hurricanes Katrina and Rita that hit the Louisiana and Texas coasts in August and September 2005.

Recent Events

In November 2005, we announced a strategic plan to restructure the company by pursuing the sale of our Gulf of Mexico assets, shifting our operating focus primarily onshore and repurchasing up to $200 million of our outstanding common stock. On March 31, 2006, we completed the sale of the Texas portion of our Gulf of Mexico assets and on June 1, 2006, we completed the sale of substantially all of our Louisiana Gulf of Mexico assets. The divestiture of these assets had a significant impact on our operating results for the year ended December 31, 2006 and on the comparability of those results to prior years.

On June 12, 2006, we received an unsolicited proposal from JANA Partners LLC, a hedge fund, to acquire our company for $62 per share, subject to due diligence and negotiation of required documentation. According to its public filings, JANA Partners beneficially owned approximately 12.3% of our outstanding common stock as of the date of the proposal. On June 26, 2006, we announced our Board of Directors determination that the unsolicited proposal made by JANA Partners was not in the best interest of our shareholders and that Lehman Brothers Inc. had been engaged to assist us in exploring a broad range of strategic alternatives to further enhance shareholder value. In connection with our review of strategic alternatives, Lehman assisted our Board in soliciting third party indications of interest for proposed business combination transactions with Houston Exploration. During the solicitation and review period, forward natural gas prices declined significantly.

On January 7, 2007, we announced the conclusion to the strategic alternatives review process with our entry into an agreement and plan of merger with Forest Oil Corporation. Under the merger agreement, Forest will acquire all of the outstanding shares of Houston Exploration for a combination of cash and Forest common stock.

Under the terms of the merger agreement, our shareholders will receive total consideration equal to 0.84 shares of Forest common stock and $26.25 in cash for each outstanding share of Houston Exploration common stock, or an aggregate of an estimated 23.6 million shares of Forest common stock and cash of $740 million. Based on the closing price of Forest common stock on January 5, 2007, the last trading day prior to announcement of the transaction, this represents $52.47 per share of merger consideration to be received by Houston Exploration shareholders. The actual value of the merger consideration to be received by our shareholders will depend on the average closing price of Forest common stock for the ten trading days ending three calendar days prior to the effective date of the merger, and the amount of cash and stock consideration will be determined by shareholder elections, subject to proration and an equalization formula. It is anticipated that the stock portion of the consideration will be tax free to Houston Exploration shareholders.

The Boards of Directors of Houston Exploration and Forest each unanimously approved the proposed merger. The merger is subject customary terms and conditions, including the approval of both Houston Exploration and Forest shareholders, and is expected to be completed in the second quarter of 2007. Upon completion of the transaction, it is anticipated that Forest shareholders would own approximately 73% of the combined company, and Houston Exploration shareholders would own approximately 27%.

Concurrently with the execution of the merger agreement, funds affiliated with JANA Partners entered into a voting agreement with Forest pursuant to which the JANA funds agreed, during the term of the voting agreement, to vote their shares of our common stock in favor of the merger with Forest and the adoption of the merger agreement and against any transaction that would impede or delay the merger with Forest, and granted to Forest a proxy to vote their shares at any

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

stockholder meeting convened to consider such matters. As of January 7, 2007, the JANA funds beneficially owned approximately 14.7% of our total issued and outstanding shares of our common stock. The voting agreement will terminate in certain instances, including an adverse recommendation change (as defined in the merger agreement) by our Board of Directors or any material amendment to the merger agreement that is adverse to us or our stockholders.

On February 8, 2007, Forest filed a registration statement on Form S-4 with the SEC, including a preliminary joint proxy statement / prospectus with respect to the merger. Also on February 8, 2007, the companies received notice of early termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvement Act with respect to the proposed transaction.

Principles of Consolidation

Our consolidated financial statements for the periods ended December 31, 2006, 2005 and 2004 include the accounts of Houston Exploration and the accounts of our wholly-owned subsidiaries. All significant inter-company balances and transactions have been eliminated.

Our consolidated financial statements for the period ended December 31, 2004 include our accounts and the accounts of our 100% owned subsidiary, Seneca-Upshur Petroleum, Inc., until June 2, 2004, when we conveyed all of the shares of Seneca-Upshur to KeySpan in connection with an asset exchange transaction. At that time, Seneca-Upshur was our only subsidiary. Seneca-Upshur is a natural gas exploration and production company located in West Virginia.

Use of Estimates

The preparation of the consolidated financial statements in conformity with accounting principals generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Our most significant financial estimates are based on remaining proved natural gas and oil reserves. Estimates of proved reserves are key components of our depletion rate for natural gas and oil properties and our full cost ceiling test limitation. In addition, estimates are used in computing taxes, preparing accruals of operating costs and production revenues, asset retirement obligations, fair value and effectiveness of derivative instruments and fair value of stock options and the related compensation expense. See Note 12 Supplemental Information on Natural Gas and Oil Exploration, Development and Production Activities (Unaudited) for more information relating to estimates of proved reserves. Because there are numerous uncertainties inherent in the estimation process, actual results could differ materially from these estimates.

Reclassifications

Certain reclassifications have been made to prior year amounts to conform to the current year presentation.

Business Segment Information

The Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) 131, Disclosures about Segments of an Enterprise and Related Information establishes standards for reporting information about operating segments. Operating segments are defined as components of an enterprise that engage in activities from which it may earn revenues and incur expenses. Separate financial information is available and this information is regularly evaluated by the chief decision maker for the purpose of allocating resources and assessing performance. Segment reporting is not applicable for us as each of our operating areas has similar economic characteristics and each meets the criteria for aggregation as defined in SFAS 131. All of our operations involve the exploration, development and production of natural gas and oil, and all of our operations are located in the United States. We have a single, company-wide management team that administers all properties as a whole rather than as discrete operating segments. We track only basic operational data by area, and do not maintain comprehensive financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis. Throughout the year, we freely allocate capital resources on a project-by-project basis across our entire asset base to maximize profitability without regard to individual areas or segments.

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THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Revenue Recognition and Gas Imbalances

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 recognize and record sales when production is delivered to a specified pipeline point, at which time title and risk of loss are transferred to the purchaser. Our arrangements for the sale of natural gas and oil are evidenced by written contracts with determinable market prices based on published indices. We continually review the creditworthiness of our purchasers in order to reasonably assure the timely collection of our receivables. Historically, we have experienced no material losses on receivables.

We incur production gas volume imbalances in the ordinary course of business. Net deliveries in excess of entitled amounts are recorded as liabilities, and 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 exists.

At December 31, 2006, we had production imbalances representing assets of $2.8 million and liabilities of $2.4 million. At December 31, 2005, we had production imbalances representing assets of $4.9 million and liabilities of $7.2 million, which included imbalances related to our offshore properties that were sold during the first six months of 2006. Our production imbalances receivable at December 31, 2006 relate primarily to certain South Texas and Arkoma Basin properties and our payables relate primarily to certain Arkoma Basin properties. A significant portion of the Arkoma Basin imbalances were assumed in connection with our initial acquisition of these properties, and due to the inherent long life and comparatively low production rate of the wells, the imbalances will likely require a long period of time to resolve. Production imbalances are included in the line items other non-current assets and other non-current liabilities on our balance sheet.

Cash and Cash Equivalents

We consider all highly liquid, short-term investments with original maturities of three months or less to be cash and cash equivalents.

Cash Designated for Investment

In connection with the sale of our Gulf of Mexico assets (see Note 10 Acquisitions and Dispositions), we initially deposited in escrow $323.7 million of the $721.6 million in total net cash proceeds received from the sale of these assets with qualified intermediaries for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code. This cash was designated for the potential future acquisition of natural gas and oil assets and was invested in interest-bearing accounts with creditworthy financial institutions. During the third quarter of 2006, designated cash of $2.0 million was used to fund qualified investments in natural gas and oil assets, and $7.6 million, representing the remaining proceeds from the sale of the Texas offshore assets, was released from escrow, as the 180-day time period for reinvestment under Section 1031 had expired. In November 2006, the remaining designated cash balance of $314.1 million relating to the sale of the Louisiana offshore assets was released from escrow, as the 180-day time period for reinvestment under Section 1031 had expired. Upon release of cash from escrow, we used $190 million to repay all outstanding borrowings under our bank credit facility and used the balance, or $124 million, for working capital purposes, which included an estimated payment for federal income taxes for the fourth quarter of 2006 of $34 million.

Interest income earned during 2006 on the amounts deposited with qualified intermediaries was approximately $8.7 million. Interest income earned was not designated for potential reinvestment in replacement properties and is included in the line item other (income) expense on our statement of operations for the year ended December 31, 2006.

Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. On the balance sheet, we report cash and cash equivalents, accounts receivable and accounts payable at cost or carrying value, which approximates fair value due to the short maturity of these instruments. See

Note 2 Long-term Debt and Notes for fair value of our debt. Our derivative financial instruments are reported on the balance sheet at fair market value. See Note 7 Derivative Instruments.

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Net Income Per Share

Basic net income per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding during the period. Diluted net income per share assumes the conversion of all potentially dilutive securities and is calculated by dividing net income by the sum of the weighted average number of shares of common stock outstanding plus all potentially dilutive securities. Diluted net loss per share is computed using the weighted average number of common shares and excludes potentially dilutive common shares outstanding, as their effect is antidilutive. For us, potentially dilutive common shares consist of employee stock options, restricted stock and restricted units.

	Years Ended December 31,		
	2006	**2005**	**2004**
	(in thousands, except per share data)		
Numerator:			
Net income	$ 67,783	$ 105,169	$ 162,824
Denominator:			
Weighted average shares outstanding	28,543	28,707	29,616
Add potentially dilutive securities: restricted stock/units and options	150	330	316
Total weighted average shares outstanding and dilutive securities	28,693	29,037	29,932
Earnings per share:			
Net income per share basic	$ 2.37	$ 3.66	$ 5.50
Net income per share diluted	$ 2.36	$ 3.62	$ 5.44

For the years ended December 31, 2006, 2005 and 2004, the calculation of shares outstanding for diluted net income per share does not include the effect of outstanding stock options to purchase 665,720, 459,215 and 755,922 shares, respectively, because the exercise price of these shares was greater than the average market price for the year, which would have an antidulitive effect on net income per share.

Comprehensive Income

Comprehensive income (loss) includes net income and certain items recorded directly to stockholders equity and classified as other comprehensive income (loss). The table below summarizes comprehensive income and provides the components of the change in accumulated other comprehensive income for the twelve-month periods ended December 31, 2006, 2005 and 2004, respectively.

	For the Year Ended December 31,		
	2006	**2005**	**2004**
		(in thousands)	
Net income	$ 67,783	$ 105,169	$ 162,824
Other comprehensive income (loss)			
Derivative instruments settled and reclassified, net of tax	44,708	171,342	44,054
Unrealized change in fair value of open derivative contracts, net of tax	204,528	(393,051)	(63,953)
Future post retirement benefit obligation, net of tax	(2,249)		

Total other comprehensive income (loss)	246,987	(221,709)	(19,899)
Comprehensive income (loss)	$ 314,770	$ (116,540)	$ 142,925

Natural Gas and Oil Properties

Full Cost Accounting. We use the full cost method to account for our natural gas and oil properties. Under full cost accounting, all costs directly associated with the acquisition, exploration and development of natural gas and oil reserves are capitalized into a full cost pool. These capitalized costs include costs of all unevaluated properties, internal general and administrative costs directly related to our acquisition, exploration and development activities and capitalized interest. We amortize these costs using a unit-of-production method. Under this method, we compute the provision for depreciation, depletion and amortization at the end of each quarter by multiplying our total production for such quarter by a depletion rate. The depletion rate is determined by dividing our total unamortized cost base by our net equivalent proved reserves at the beginning of the quarter. Our total unamortized cost base consists of the following:

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our full cost pool (including assets associated with retirement obligations); plus

estimates for future development costs (excluding liabilities associated with retirement obligations); less

unevaluated properties and their related costs; less

estimates for salvage.

Costs associated with unevaluated properties are excluded from our total unamortized cost base until we have made a determination as to the existence of proved reserves. We review our unevaluated properties at the end of each quarter to determine whether the costs incurred should be reclassified to the full cost pool and, thereby, subject to amortization. Sales and abandonment of natural gas and oil properties being amortized currently are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustments would significantly alter the relationship between capitalized costs and proved natural gas and oil reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the reserve quantities of a cost center. However, we evaluate each asset sale using both qualitative indicators and quantitative measures to determine whether gain or loss recognition is appropriate.

Under full cost accounting, total capitalized costs (net of accumulated depreciation, depletion and amortization) less related deferred taxes may not exceed an amount equal to the present value of future net revenues from proved reserves, discounted at 10% per annum, plus the lower of cost or fair value of unevaluated properties, plus estimated salvage value, less income tax effects (the ceiling limitation). We perform a test of this ceiling limitation at the end of each quarter. If our total capitalized costs (net of accumulated depreciation, depletion and amortization) less related deferred taxes are greater than the ceiling limitation, a writedown or impairment of the full cost pool is required. A writedown of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders equity in the period of occurrence and typically results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a writedown is not reversible at a later date.

The ceiling test is calculated using natural gas and oil prices in effect as of the balance sheet date, as adjusted for basis or location differentials as of the balance sheet date and held constant over the life of the reserves (net wellhead prices). If applicable, these net wellhead prices would be further adjusted to include the effects of any fixed price arrangements for the sale of natural gas and oil. Historically, we have used derivative financial instruments to hedge against the volatility of natural gas prices. If our derivative contracts qualify and if they are designated as cash flow hedges under SFAS 133, Accounting for Derivative Instruments and Hedging Activities, then in accordance with SEC guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation. Because our derivative contracts ceased to qualify as cash flow hedges during the first quarter of 2006, our ceiling test calculation at December 31, 2006 did not include the future cash flows from our hedging program. In addition, subsequent to the adoption of SFAS 143, Accounting for Asset Retirement Obligations, the future cash outflows associated with settling asset retirement obligations are excluded from the computation of the discounted present value of future net revenues for the purposes of the ceiling test calculation.

In calculating our ceiling test at December 31, 2006, we estimated that, using an average net wellhead price of $4.94 per Mcf, the carrying value of our full cost pool exceeded the ceiling limitation by approximately $582.8 million ($376.5 million net of tax). However, since December 31, 2006 and prior to filing this Annual Report, the market price for natural gas increased such that, using an average net wellhead price of $6.63 per Mcf on February 20, 2007, the carrying value of our full cost pool exceed the ceiling limitation by approximately $19.0 million ($12.3 million net of tax). Accordingly, we recorded a writedown to our natural gas and oil properties and a non-cash charge and reduction to earnings in the fourth quarter of 2006 of $12.3 million, net of tax. In calculating our ceiling test at December 31, 2005 and 2004, we estimated, using wellhead prices of $8.21 per Mcfe and $5.75 per Mcfe, respectively, that we had a full cost ceiling cushion at each of the respective balance sheet dates, whereby the carrying value of our full cost pool was less than the ceiling limitation by $329.9 million (net of tax) for 2005 and $399.3

million (net of tax) for 2004. No writedown was required.

Unevaluated Properties. The costs associated with unevaluated properties are not initially included in the amortization base and relate to unproved leasehold acreage, wells and production facilities in progress and wells pending determination, together with capitalized interest costs for these projects. Unevaluated leasehold costs are transferred to the amortization base with the costs of drilling the related well once a determination has been made or upon expiration of a lease. Costs of seismic data are allocated to various unproved leaseholds and transferred to the amortization base with the associated leasehold costs on a specific project basis. Costs associated with wells in progress and completed wells that have yet to be evaluated are transferred to the amortization base once a determination is made whether or not proved reserves can be

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assigned to the property. Costs of dry holes are transferred to the amortization base immediately upon determination that the well is unsuccessful.

We assess all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value. We assess our properties on an individual basis or as a group if properties are individually insignificant. Our assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

Of the $28.3 million of unevaluated property costs at December 31, 2006 that have been excluded from the amortization base, $11.1 million were incurred during 2006, $12.0 million were incurred in 2005, $4.7 million were incurred in 2004 and $0.5 million were incurred in years prior to 2004. Of the $107.1 million of unevaluated property costs at December 31, 2005 that have been excluded from the amortization base, $37.9 million were incurred during 2005, $18.3 million were incurred in 2004, $30.5 million were incurred in 2003 and $20.4 million were incurred prior to 2003. We estimate that substantially all of our costs classified as unproved as of the balance sheet date will be evaluated and transferred within a four-year period.

Asset Retirement Obligations

For us, asset retirement obligations (ARO) represent the future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and other facilities. SFAS 143, Accounting for Asset Retirement Obligations, requires that the fair value of a liability for an asset s retirement obligation be recorded in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the corresponding cost be capitalized as part of 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, an adjustment is made to the full cost pool, with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves. We carry ARO assets on the balance sheet as part of our full cost pool, and include these ARO assets in our amortization base for purposes of calculating depreciation, depletion and amortization expense. For purposes of calculating the ceiling test, the future cash outflows associated with settling the ARO liability are excluded from the computation of the discounted present value of estimated future net revenues.

The following table describes changes in our asset retirement liability during each of the years ended December 31, 2006 and 2005. The ARO liability in the table below includes amounts classified as both current and long-term at December 31st.

	Years Ended December 31,	
	2006	2005
	(in thousands)	
ARO liability at January 1,	$ 119,671	$ 91,746
Accretion expense	3,373	5,278
Liabilities incurred from drilling	7,656	7,520
Liabilities incurred assets acquired	1,312	5,783
Liabilities settled assets sold	(88,375)	(32)
Liabilities settled assets abandoned		(971)
Changes in estimates	29,145	10,347
ARO liability at December 31,	$ 72,782	$ 119,671

Other Property and Equipment

Other property and equipment includes the costs of various gathering facilities that are depreciated using the unit-of-production basis utilizing estimated proved reserves attributable to the facilities. Also included in other property and equipment are costs of office furniture, fixtures and computer equipment and other office equipment which are recorded at cost and depreciated using the straight-line method over estimated useful lives ranging from two to five years.

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Inventories

Inventories consist primarily of tubular goods used in our operations and are stated at the lower of the specific cost of each inventory item or market value.

Income Taxes

We determine deferred taxes based on the estimated future tax effect of differences between the financial statement and tax basis of assets and liabilities given the provisions of enacted tax laws as of the balance sheet dates. These differences relate primarily to

- intangible drilling and development costs associated with natural gas and oil properties, which are capitalized and amortized for financial reporting purposes and expensed as incurred for tax reporting purposes; and

- provisions for depreciation and amortization for financial reporting purposes that differ from those used for income tax reporting purposes.

General and Administrative Costs and Expenses

Under the full cost method of accounting, we capitalize only those internal general and administrative costs that are directly associated with our acquisition, exploration and development activities, such as salaries, benefits and incentive compensation for geological and geophysical employees and other specifically identifiable non-payroll costs. These capitalized general and administrative costs do not include costs related to production operations, general corporate overhead or other activities not directly attributable to our acquisition, exploration and development efforts. We capitalized general and administrative costs directly related to our acquisition, exploration and development activities, during 2006, 2005 and 2004 of $ 20.2 million, $16.9 million and $14.8 million, respectively.

We receive reimbursement for administrative and overhead expenses incurred on behalf of other working interest owners on properties we operate. These reimbursements totaling $2.2 million, $2.1 million and $2.2 million for the years ended December 31, 2006, 2005 and 2004, respectively, were allocated as reductions to general and administrative expenses incurred. Generally, we do not receive any excess of reimbursements or fees over the costs incurred; however, if we did, we would credit the excess to the full cost pool to be recognized through lower cost amortization as production occurs.

Capitalization of Interest

We capitalize interest only on investments in unevaluated properties and projects for which exploration or development activity is in progress. Interest is capitalized during the period of time that these properties and projects are classified as unevaluated properties and not subject to depreciation, depletion and amortization. See Note 1 Summary of Organization and Significant Accounting Policies *Natural Gas and Oil Properties Unevaluated Properties* for a discussion of unevaluated properties and our assessment process. For the years ended December 31, 2006, 2005 and 2004, we capitalized interest costs of $4.4 million, $8.8 million and $8.4 million, respectively.

Concentration of Credit Risk

Substantially all of our accounts receivable result from natural gas and oil sales or joint interest billings to third parties in the oil and gas industry. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. Historically, we have not experienced credit losses on these receivables. Based on the current demand for natural gas and oil, we do not expect that termination of sales to any of our current purchasers would have a material adverse effect on our ability to find replacement purchasers and to sell our production at favorable market prices.

Further, our derivative instruments also expose us to credit risk in the event of nonperformance by counterparties. Generally, these contracts are with major investment grade financial institutions and other substantive counterparties. We believe that our credit risk related to the natural gas derivative contracts is no greater than the risk associated with the primary contracts and that the elimination of price risk through our hedging activities reduces volatility in our reported results of operations, financial position and cash flows from period to period and lowers our overall business risk; however, as a result of these same hedging activities, we may be exposed to greater credit risk in the future.

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Derivative Instruments and Hedging Activities

We account for derivative instruments utilizing SFAS 133, Accounting for Derivative Instruments and Hedging Activities, as amended. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we have historically utilized derivative instruments to hedge future sales prices on a significant portion of our natural gas production. Our derivative instruments are not held for trading purposes. Our hedging policy allows us to implement a wide variety of hedging strategies, including swaps, collars and options. We generally execute derivative contracts with significant, creditworthy financial institutions. Although our hedging program is intended to protect a portion of our cash flows from downward price movements, certain hedging strategies, specifically the use of swaps and collars, may also limit our ability to realize the full benefit of future price increases, as in recent years. In addition, because our derivative instruments are typically indexed to the New York Mercantile Exchange (NYMEX) price, as opposed to the index price where the gas is actually sold, our hedging strategy may not fully protect our cash flows when there are significant price differentials between the NYMEX price and index price at the point of sale.

Historically, all of our derivative contracts qualified for hedge accounting at inception of the contract and were designated as cash flow hedges. Under hedge accounting, derivative contracts designated as cash flow hedges are recorded on the balance sheet as either an asset or liability at fair market value, and changes in fair market value (representing unrealized gains or losses) are deferred in accumulated other comprehensive income. Gains and losses are reclassified from accumulated other comprehensive income to the income statement as a component of natural gas and oil revenues in the period when sale of the related production occurs. The portion of the derivative instrument that is ineffective as a hedge, if any, is recorded directly to the income statement and is included as a component of natural gas and oil revenues. For us, ineffectiveness typically results from changes at the end of the current period in the price differentials between the index price of the derivative contract, which typically is a NYMEX price, and the index price for the point of sale for the cash flow that is being hedged.

Under SFAS 133, we are required to assess the effectiveness of all our derivative contracts at inception and at least every three months. If our derivative contracts cease to be effective as cash flow hedges, they would no longer qualify for hedge accounting and mark-to-market accounting would then be utilized. Gains or losses deferred in accumulated other comprehensive income are fixed at the time they cease to qualify for hedge accounting and remain deferred in accumulated other comprehensive income until the related production occurs, at which time these gains or losses are reclassified to income. Subsequent changes in the fair market value of the derivative contracts (representing unrealized gains or losses) are recognized in income as a component of natural gas and oil revenues.

During the fourth quarter of 2005, the portion of our hedged production allocated to the Houston Ship Channel index failed to qualify for hedge accounting due to a loss of correlation with the NYMEX price caused primarily by the impact of Hurricanes Katrina and Rita. During the first quarter of 2006, the portion of our hedged production allocated to the Arkoma index failed to qualify for hedge accounting due to a loss of correlation with the NYMEX price caused in part by the residual effects of the hurricanes, as well as an increase in the natural gas supply in the mid-continent region primarily associated with mild winter and pipeline expansions in the region. Finally, in February 2006 in connection with our entry into a definitive purchase and sale agreement to sell the Texas portion of our Gulf of Mexico assets (see Note 10 Acquisitions and Dispositions *Sale of Texas Gulf of Mexico Assets*), the remaining portion of our open derivative contracts ceased to qualify for hedge accounting. As a result, subsequent to February 2006, mark-to-market accounting applies to all of our open derivative contracts, and changes in the fair market value of these open contracts are recognized in income as either a gain or loss and included as a component of natural gas and oil revenues.

At December 31, 2006, an unrealized loss of $18.5 million, net of tax, remains deferred in accumulated other comprehensive income. This loss represents the fixed value of our remaining open derivative contracts deferred in accumulated other comprehensive income at the time they ceased to qualify for hedge accounting. All of these deferred losses will be reclassified and recognized in future earnings at the time when sale of the related natural gas production occurs. Over the next 12-month period, we expect to reclassify from accumulated other comprehensive income to earnings a net loss of $11.1 million, net of tax, leaving $7.4 million to be recognized thereafter. At

December 31, 2006, our open derivative contracts extended through each of the twelve months of 2007 and 2008. See Note 7 Derivatives Instruments for additional disclosures.

We enter into a substantial portion of our derivative contracts with counterparties who are participant banks in our bank credit facility. Under our arrangements with these banks, we generally have no margin obligation so long as the counterparty remains in our bank group or is otherwise secured at an equal rate with our bank group. As to other counterparties, with one exception, we have no margin obligation so long as we satisfy certain credit rating thresholds with

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prescribed rating agencies. In one instance we have a margin exposure threshold, above which we must provide the counterparty margin to secure our hedge obligations. At December 31, 2006 and 2005, we did not have any letters of credit issued to secure performance for our open derivative contracts.

Accounting for Stock Options

On January 1, 2003, we adopted the fair value expense recognition provisions of SFAS 123, Accounting for Stock-Based Compensation, as amended by SFAS 148, Accounting for Stock Based Compensation Transition and Disclosure using the prospective method as defined by SFAS 148. Accordingly, we recognized compensation expense for all stock options granted subsequent to January 1, 2003. On January 1, 2006, we adopted SFAS 123(R), Share-Based Payment using the modified prospective method as defined by SFAS 123 (R). Accordingly, we now recognize compensation expense for all stock options, including the unvested portion of all grants made prior to our initial adoption of SFAS 123 on January 1, 2003. Prior period amounts have not been restated. During 2006, we recognized additional stock compensation expense for grants made prior to our initial adoption of SFAS 123, not vested as of January 1, 2006, of $1.4 million ($0.9 million net of tax). Based on current estimates, we expect to recognize additional expense of $0.7 million ($0.4 million net of tax) related to these option grants during 2007. See Note 4 Employee Benefit and Stock Compensation Plans *Stock Compensation Expense* for additional disclosure relating to our stock plans and related stock compensation expense.

Accounting for Postretirement Benefits

In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans. SFAS 158 amends SFAS 87, Employers Accounting for Pensions, SFAS 88, Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits, SFAS 106, Employers Accounting for Postretirement Benefits Other Than Pensions, and SFAS 132 (revised 2003), Employers Disclosures about Pensions and Other Postretirement Benefits. On December 31, 2006, we adopted the recognition and disclosure provisions of SFAS 158. SFAS No. 158 requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan as an asset or liability on its balance sheet and to recognize changes in the funded status in the year in which the changes occur through comprehensive income. In addition, SFAS 158 requires employers to measure the funded status of a plan as of the date of its year-end balance sheet, which for us is December 31st and to provide additional disclosures. The effect of adopting SFAS 158 has been included in our accompanying consolidated financial statements.

The table below summarizes the effect of adopting SFAS 158 on our consolidated balance sheet as of December 31, 2006 and the recognition of (i) our total unfunded benefit obligation of $5.1 million at December 31, 2006 as a liability; and (ii) prior service costs and net actuarial losses of $3.5 million ($2.2 million net of tax) as a component of accumulated other comprehensive income. See Note 4 Employee Benefit and Stock Compensation Plans *Supplemental Executive Retirement Plan* for additional disclosures.

	Before Adopting SFAS 158	Adjustment to adopt SFAS 158	After Adopting SFAS 158
		(in thousands)	
Assets:			
Other current assets current tax benefit	$	$ 36	$ 36
Total assets		36	36
Liabilities:			
Accounts payable and accrued liabilities	1,596	(1,496)	100
Other non-current liabilities		5,016	5,016

Deferred tax liability (benefit)				(1,235)		(1,235)
Total liabilities		1,596		2,285		3,881
Stockholders equity:						
Accumulated other comprehensive income (loss)				(2,249)		(2,249)
Total stockholders equity	$		$	(2,249)	$	(2,249)

Recent Accounting Pronouncements

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. SFAS 157 defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures regarding fair value measurements. SFAS 157 does not add any new fair value measurements, but it does change current practice and is intended to increase consistency

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and comparability in such measurement. The provisions of SFAS 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007. Any amounts recognized upon adoption as a cumulative effect adjustment will be recorded to the opening balance of retained earnings in the year of adoption. We are currently evaluating the impact of adopting SFAS 157 on our financial statements and assessing early adoption which is permitted and would occur as of the first quarter of fiscal 2007, or in our case, January 1, 2007.

In July 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement 109 (FIN 48), which clarifies the accounting for uncertainty in tax positions taken or expected to be taken in a tax return, including issues relating to financial statement recognition and measurement. FIN 48 provides that the tax effects from an uncertain tax position can be recognized in the financial statements only if the position is more-likely-than-not to be sustained if the position were to be challenged by a taxing authority. The assessment of the tax position is based solely on the technical merits of the position, without regard to the likelihood that the tax position may be challenged. If an uncertain tax position meets the more-likely-than-not threshold, the largest amount of tax benefit that is more than 50 percent likely to be recognized upon ultimate settlement with the taxing authority, is recorded. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. Consistent with the requirements of FIN 48, we adopted FIN 48 on January 1, 2007. We are currently evaluating the impact of adopting FIN 48 and do not expect the interpretation will have a material impact on our results of operations or financial position.

NOTE 2 Long-Term Debt and Notes

	As of December 31, 2006	As of December 31, 2005
	(in thousands)	
Senior Debt:		
Revolving bank credit facility, due November 30, 2010	$	$ 422,000
Subordinated Debt:		
7% senior subordinated notes, due June 15, 2013	175,000	175,000
Total long-term debt and notes	$ 175,000	$ 597,000

The carrying amount of borrowings outstanding under the revolving bank credit facility approximates fair value as the interest rates are tied to current market rates. At December 31, 2006, the quoted market value of our $175 million of 7% senior subordinated notes was 98.5% of the $175 million carrying value or $172.4 million. At December 31, 2005, the quoted market value of our $175 million of 7% senior subordinated notes was 95.4% of the $175 million carrying value or $167 million. At December 31, 2006, principal payments due over the next five-year period and thereafter are as follows:

	2007	2008	2009	2010	2011	After 2012
			(in thousands)			
Revolving bank credit facility	$	$	$	$	$	$
7% senior Subordinated Notes						175,000
Total maturities	$	$	$	$	$	$ 175,000

Revolving Credit Facility

We maintain a revolving credit facility with a syndicate of lenders led by Wachovia Bank, National Association, as issuing bank and administrative agent, The Bank of Nova Scotia and Bank of America as co-syndication agents and BNP Paribas and Comerica Bank as co-documentation agents. The facility provides us with a commitment of $750 million, which may be increased at our request and with prior approval from the required lenders to a maximum of $850 million. Amounts available for borrowing under the credit facility are limited to a borrowing base that is redetermined semi-annually on April 1st and October 1st. Up to $60 million of our borrowing base is available for the issuance of letters of credit. As of December 31, 2006, our borrowing base was $500 million. We expect our current $500 million borrowing base to remain in effect until the next scheduled semi-annual redetermination on April 1, 2007. Outstanding borrowings under the revolving credit facility are secured by substantially all of our natural gas and oil assets as well as certain other assets and rank senior in right of payment to our $175 million of 7% senior subordinated notes. The facility matures on November 30, 2010. At December 31, 2006, we had no outstanding borrowings under the credit facility and $0.3 million in outstanding letter of credit obligations. Although we had no outstanding indebtedness under our bank credit facility as of December 31,

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2006 or as of the date of this Annual Report, consummation of the pending merger will require the refinancing or repayment of any outstanding indebtedness thereunder.

Interest is payable on borrowings under our revolving credit facility as follows:

- on base rate loans, at a fluctuating rate, or base rate, equal to the sum of (a) the greater of the Federal funds rate plus 0.5% or Wachovia s prime rate plus (b) a variable margin between 0.00% and 0.50%, depending on the amount of borrowings outstanding under the credit facility, or

- on fixed rate loans, a fixed rate equal to the sum of (a) a quoted LIBOR rate divided by one minus the average maximum rate during the interest period set for certain reserves of member banks of the Federal Reserve System in Dallas, Texas, plus (b) a variable margin between 1.00% and 1.75%, depending on the amount of borrowings outstanding under the credit facility.

Interest is payable on base-rate loans on the last day of each calendar quarter. Interest on fixed-rate loans is generally payable at maturity or at least every 90 days if the term of the loan exceeds three months. In addition to interest, we must pay a quarterly commitment fee of between 0.30% and 0.50% per annum on the unused portion of the borrowing base.

Our revolving credit facility contains customary financial and other covenants that place restrictions and limits on, among other things, the incurrence of debt, guarantees, liens, leases and certain investments. The credit facility also restricts and limits our ability to pay cash dividends, purchase or redeem our stock, and sell or encumber our assets. Financial covenants require us to, among other things:

- maintain a ratio of earnings before interest, taxes, depreciation, depletion and amortization (EBITDA) to cash interest payments of at least 3.00 to 1.00;

- maintain a ratio of total debt to EBITDA of not more than 3.50 to 1.00; and

- hedge no more than 85% of our projected production during any calendar year.

At December 31, 2006 and 2005, we were in compliance with all covenants.

Senior Subordinated Notes

On June 10, 2003, we issued $175 million of 7% senior subordinated notes due June 15, 2013. The notes bear interest at a rate of 7% per annum with interest payable semi-annually on June 15 and December 15. We may redeem the notes at our option, in whole or in part, at any time on or after June 15, 2008, at a price equal to 100% of the principal amount plus accrued and unpaid interest, if any, plus a specified premium that decreases yearly from 3.5% in 2008 to 0% in 2011 and thereafter. The notes are general unsecured obligations and rank subordinate in right of payment to all of our existing and future senior debt, including the revolving bank credit facility, and will rank senior or equal in right of payment to all of our existing and future subordinated indebtedness.

The indenture governing the notes contains covenants that, among other things, restrict or limit:

- incurrence of additional indebtedness and issuance of preferred stock;

- repayment of certain other indebtedness;

- payment of dividends or certain other distributions;

- investments and repurchases of equity;

- use of the proceeds of assets sales;

- transactions with affiliates;

creation, incurrence or assumption of liens;

merger or consolidation and sales or other dispositions of all or substantially all of our assets;

entering into agreements that restrict the ability of our subsidiary to make certain distributions or payments; or

guarantees by our subsidiary of certain indebtedness.

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In addition, upon the occurrence of a change of control (as defined in the indenture and including the pending merger with Forest), the obligor or successor obligor on the notes will be required to offer to purchase the notes at a purchase price equal to 101% of the aggregate principal amount, plus accrued and unpaid interest and liquidated damages, if any.

NOTE 3 Stockholders Equity

Stock Repurchase Program

On November 4, 2005, and in conjunction with the divestiture of all of our Gulf of Mexico assets, our Board of Directors approved discretionary repurchases from time to time over twelve months of up to $200 million in company stock. In May 2006, we initiated our share repurchases, and during May and June 2006, we repurchased a total of 1,176,500 shares, or approximately 4% of our outstanding common stock, in the open market at a weighted average price of $52.39 per share for a total cost of approximately $61.6 million. All repurchases were paid for in cash and funded with cash on hand or borrowings under our revolving credit facility. All repurchased shares were retired.

Stockholder Rights Plan

In August 2004, we adopted a stockholder rights plan designed to assure that our stockholders receive fair and equal treatment in the event of an unsolicited attempt to takeover our company and to protect against abusive or coercive takeover tactics that are not in the best interest of our company or its stockholders. On May 2, 2005, the Board of Directors approved an amendment to the rights agreement to increase the acquisition threshold of an acquiring party from 10% to 15%. The rights under the plan expire on August 12, 2014, unless redeemed earlier by our Board of Directors. The Board of Directors can redeem the rights at a price of $.01 per right at any time before the rights become exercisable, and thereafter only in limited circumstances. On January 7, 2007, in connection with the merger agreement with Forest, we amended the rights agreement to render the rights agreement inapplicable to (i) the approval, execution, delivery, adoption and performance of the merger agreement with Forest and the voting agreement among Forest and certain affiliates of JANA Partners LLC, (ii) the consummation of the pending merger or the other transactions contemplated by the merger agreement and (iii) the announcement of the merger, the merger agreement and the voting agreement. See Note 11 Subsequent Events *Pending Merger with Forest Oil Corporation.*

Increase in Number of Shares Outstanding

In April 2005, our Board of Directors received shareholder approval to increase the number of shares we are authorized to issue to up to 105,000,000 shares of stock, including up to 100,000,000 shares of common stock and up to 5,000,000 shares of preferred stock.

KeySpan s Divesture of Our Common Stock

Through a series of three separate transactions, the first in February 2003 and the last in November 2004, KeySpan completely divested of its investment in the common stock of our company. The three transactions are as follows:

Issuance of 3,000,000 Shares to the Public and Concurrent Repurchase of 3,000,000 Shares from KeySpan. In connection with our initial public offering in September 1996, we entered into a registration rights agreement with KeySpan pursuant to which we were obligated, at KeySpan s election, to facilitate KeySpan s sale of its shares of our stock by registering the shares under the Securities Act of 1933 and assisting in KeySpan s selling efforts. During February of 2003, KeySpan notified us of its desire to sell 3,000,000 shares of their Houston Exploration stock. To accomplish the transaction, we sold 3,000,000 newly issued shares of our stock in a public offering under our shelf registration statement for net proceeds of $26.40 per share, or an aggregate $79.2 million, and simultaneously bought a like number of KeySpan s shares of our stock for the same price per share. We cancelled the 3,000,000 shares acquired from KeySpan immediately following the repurchase. KeySpan reimbursed us for all costs and expenses, and the transaction had no impact on our capitalization. The transaction was evidenced in a stock purchase agreement, dated February 26, 2003. As a result of the transactions, KeySpan s interest in our outstanding shares decreased from 66% to 55%.

KeySpan Exchange and Offering. On June 2, 2004, we completed an asset exchange transaction with KeySpan pursuant to which we redeemed and cancelled 10,800,000 shares of our common stock owned by KeySpan in exchange for all the stock of Seneca-Upshur Petroleum, Inc., our wholly-owned subsidiary, to which we contributed all of our Appalachian Basin assets, valued at $60 million, and $389 million in cash, for a total exchange value of $449 million. This transaction is referred to as the KeySpan Exchange. The KeySpan Exchange was intended to qualify as a tax-free exchange under Section 355(a) of the Internal Revenue Code.

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To fund the cash portion of the exchange, on June 2, 2004, we sold 6,200,000 shares of our common stock in a registered public offering at $48.00 per share, (the Offering), and contributed to Seneca-Upshur substantially all of the net proceeds from the Offering (approximately $282 million), together with an additional $107 million of proceeds from bank borrowings. We then conveyed to KeySpan all of the shares of Seneca-Upshur in exchange for 10,800,000 shares of our common stock owned by KeySpan.

On June 23, 2004, the underwriters of our Offering exercised a portion of their over-allotment option and we sold an additional 620,000 shares of common stock at $48.00 per share for net proceeds of $28.6 million. The proceeds from the over-allotment were used to reduce bank borrowings.

Our redemption and cancellation of the 10,800,000 shares received from KeySpan and our issuance of 6,820,000 new shares resulted in a net 3,980,000 decrease in the outstanding shares of our common stock, and thereby reduced KeySpan s ownership from approximately 54% to 24%. As a result of the KeySpan Exchange and Offering, our bank borrowings increased by a net $79 million and we incurred approximately $5.1 million in compensation and other expenses related to special bonuses awarded to executives and key employees who assisted in structuring and consummating the transactions. As a result of the reduction in ownership, KeySpan agreed to reduce its representation on our Board of Directors from five to two directors. Our Chief Executive Officer, William G. Hargett, was elected Chairman of the Board, replacing Robert B. Catell, Chairman and Chief Executive Officer of KeySpan, who remains on the Board.

KeySpan Secondary Offering. On November 24, 2004, KeySpan completed a secondary public offering of its remaining 6,580,392 shares of our common stock at $56.25 per share. All shares were offered by KeySpan under our shelf registration statement filed with the Securities and Exchange Commission on March 16, 2004. We did not receive any proceeds from the sale of these shares in the offering. Subsequent to the offering, KeySpan no longer held any common stock of our company.

NOTE 4 Employee Benefit and Stock Compensation Plans

401(k) Plan

We maintain a tax-qualified defined contribution plan under Section 401(k) of the Internal Revenue Code for our employees. All employees are eligible to participate in the plan upon reaching 21 years of age and completing one month of service. Participants may elect to have us contribute on their behalf up to 12.5% of their total compensation (subject to limitations imposed under the Internal Revenue Code) on a before tax basis. We make a matching contribution of $1.00 for each $1.00 of employee deferral, subject to limitations imposed by the 401(k) plan and the Internal Revenue Code. The amounts contributed under the 401(k) plan are held in a trust and invested at the direction of each participant among various investment funds. An employee s salary deferral contributions to the 401(k) plan are 100% vested. Our matching contributions vest at the rate of 20% per year of service. Participants are entitled to distribution of their vested account balances upon termination of employment. We made contributions to the 401(k) plan of $1.6 million, $1.4 million and $1.2 million, respectively, for the years ended December 31, 2006, 2005 and 2004. On January 7, 2007 and in connection with our entry into the merger agreement with Forest (see Note 11 Subsequent Events *Pending Merger with Forest Oil Corporation*), the 401(k) plan was amended to provide for the full vesting of all plan account balances at the effective time of the pending merger with respect to plan participants who are employed by Houston Exploration immediately prior to the effective time of the merger.

Deferred Compensation Plan

We maintain a deferred compensation plan for the benefit of our employees. We have two such plans which are substantially identical, except for differences attributable to the American Jobs Creation Act of 2004, covering two separate time periods. On July 25, 2006, we amended the 2002 deferred compensation plan to prohibit deferrals or contributions to the plan after December 31, 2004 and to transfer to the 2005 deferred compensation plan all amounts not vested as of December 31, 2004, effectively grandfathering within the 2002 plan all participant deferrals and company matching contributions that were vested as of December 31, 2004, as well as the earnings and losses on those amounts. On July 25, 2006, we also adopted the 2005 deferred compensation plan, which covers all participant deferrals and Company matching contributions from and after January 1, 2005, as well as any contributions made prior to such date that were not vested as of December 31, 2004, and the earnings or losses on such amounts.

Each deferred compensation plan is a non-qualified plan and is intended to supplement our 401(k) plan by allowing highly compensated employees to save on a tax deferred basis a portion of their eligible compensation subject to limitations imposed by the plan. Under the terms of the plan, employees who have made the maximum allowable contribution to their

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401(k) accounts for any year may elect to defer an additional portion of their compensation into the deferred compensation plan. We match 100% of each employee s deferral up to an aggregate contribution of 12.5% under both the 401(k) plan and the deferred compensation plan. During 2006, 2005 and 2004, we made matching contributions totaling $1.5 million, $1.2 million and $0.7 million, respectively, to the deferred compensation plan. Employer contributions vest 20% per year and become fully vested after a five-year period. We make contributions to a grantor trust to fund plan benefits, but the assets of the trust are subject to the claims of our general creditors. Assets of the grantor trust are invested, at the direction of the employee, in various investment funds. Income on trust assets is treated as our income. Participants are entitled to a benefit attributable to their deferrals and the vested portion of our matching contributions at predetermined future dates or upon termination of their employment.

At December 31, 2006 and 2005, the fair market value of the assets held in the trust was $ 9.7 million and $8.5 million, respectively. These balances are carried on our balance sheet as a non-current asset together with a corresponding non-current liability for the same amount and are located in the line items Other Non-Current Assets and Other Non-Current Liabilities. Vesting under the deferred compensation plan follows vesting under our 401(k) plan; therefore, all plan account balances will become fully vested at the effective time of the merger with Forest (see Note 11 Subsequent Events *Pending Merger with Forest Oil Corporation*) with respect to plan participants who are employed by Houston Exploration immediately prior to the effective time of the merger.

Deferred Compensation Plan for Non-Employee Directors

We maintain a deferred compensation plan for non-employee, non-affiliated directors. We have two such plans which are substantially identical, except for differences attributable to the American Jobs Creation Act of 2004, covering two separate time periods. On April 26, 2005, we amended the 1997 director deferred compensation plan to prohibit deferrals under to the plan after December 31, 2004, effectively grandfathering within the 1997 director plan all participant deferrals and company matching contributions that were vested as of December 31, 2004, as well as the earnings and losses on those amounts. On April 26, 2005, we also adopted the post-2004 director deferred compensation plan, which covers all participant deferrals from and after January 1, 2005, and the earnings or losses on such amounts.

Each director deferred compensation plan is a non-tax qualified plan designed to allow members of our Board of Directors who are not employees to defer retainer and/or meetings fees on a pre-tax basis, to be credited with interest or deemed invested in phantom stock rights that are tied to the market price of our common stock on the date services are performed. The term phantom stock rights refers to units of value that track the performance of our company s common stock. These units are not convertible to stock and do not possess any voting rights. Phantom stock rights are exchanged for a cash distribution upon retirement from our Board of Directors. Deferred fees under the plans totaled $0.9 million at December 31, 2006 and 2005.

Employee Annual Incentive Compensation Plan

We maintain an annual incentive compensation plan that provides an annual incentive bonus to all full-time employees if certain performance goals are met during the year. The plan is administered by our Chief Executive Officer on behalf of our Board of Directors and the Compensation Committee. Annual objectives and incentive opportunity levels are established and approved by the Compensation Committee. Incentive awards are earned based on our actual performance in relation to pre-established objectives and on an assessment of individual contribution during the year. We incurred incentive compensation costs under this plan of approximately $4.6 million, $5.0 million and $6.2 million in 2006, 2005 and 2004.

Retention Bonus Plan

In July 2005, we adopted a retention bonus plan designed to retain key non-executive employees, primarily involved in the operations of our business. Under the terms of the plan, participants were awarded a bonus equal to one year s base salary, with 50% payable in cash and 50% payable in restricted stock of the company. Participants earn their bonus over a 36 month period, with the first installment of cash and stock delivered January 26, 2007, or 18 months after implementing the plan, and the final installment is due to participants employed with us on July 26, 2008. The number of shares of restricted stock to be issued was determined by dividing 50% of the employee s base salary by the closing price of our shares on July 26, 2005 which was equal to $58.88. At December 31, 2006 and 2005, an aggregate of 41,882 and 52,501 restricted units, respectively, were outstanding under the plan. For the years ended December 31, 2006 and 2005, we incurred total costs of

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approximately $2.8 million and $1.3 million, respectively in compensation expense under the plan. Benefits under the plan are forfeited if a participant s employment with our company is terminated before the payment date. On January 26, 2007, the first payment under this plan was made. We issued 12,295 shares of common stock at $52.35 per share, or $0.6 million, in exchange for the vested restricted stock units under this plan and made cash payments totaling $1.2 million.

Immediately prior to the effective time of the merger with Forest, each restricted stock unit outstanding under the retention bonus plan will be fully vested. Shares of our common stock will be issued in exchange for the restricted stock unit, and these shares will be treated at the effective time of the merger the same as, and will have the same rights and be subject to the same conditions as, other shares of our common stock. Participants in this plan that continue to remain employed with Forest after completion of the merger will receive the second portion of their cash payment on July 26, 2008.

Supplemental Executive Retirement Plans

Effective January 1, 2006, we adopted a new Supplemental Executive Retirement Plan (SERP) to provide retirement benefits to certain management level or other highly compensated employees. The SERP is an unfunded, non-tax qualified defined benefit pension plan. Initial participation in the SERP is currently limited to all our executive officers. Participants in the SERP will be entitled to a monthly retirement benefit payable for life. The annual amount of this retirement benefit is equal to 2.5% times final average compensation times years of service with the company (not to exceed 20 years), reduced by an annuity (offset) based on a hypothetical account that is credited with 6% of the participant s annual base salary and bonus paid each year and investment returns as defined in the Plan. Participants are fully vested in their benefits after five years of plan participation or age 65, whichever is earlier. If a vested participant retires prior to age 65, then the monthly retirement benefit as described above (before reduction for the offset) will be reduced by 5% for each year that retirement precedes age 65. In the event a participant is terminated for cause before becoming vested in his or her benefits, all benefits under the SERP will be forfeited. In general, benefits will be paid when the participant retires from the company or beginning at age 65. However, in the event of a change of control (as defined in the plan and including the pending merger with Forest), the benefit will be paid as a lump-sum if a participant s employment is terminated by us without cause or the participant resigns for good reason within two years following a change of control. All benefits become fully vested upon a change of control whether or not a participant s employment is terminated.

On January 7, 2007 and in connection with our entry into the merger agreement with Forest, the SERP was amended to eliminate provisions relating to the appointment of an independent plan administrator. Assuming the termination of employment of each of our executive officers as of June 30, 2007 following the merger with Forest, the total lump sum that would be payable under the SERP is estimated at approximately $3.2 million. Pursuant to the terms of the merger agreement, Forest will assume this payment obligation under our SERP as of the effective time of the merger.

The assumptions and disclosures included herewith relating to our postretirement benefit plan do not include the effect of the pending merger with Forest, as the merger agreement was entered into subsequent to December 31, 2006. We use a December 31st measurement date for our benefit obligations. The weighted average assumptions used to determine our benefit obligations at December 31, 2006 were (i) a discount rate of 5.75%, and (ii) a rate of 5.00% for increases in compensation. Our SERP was adopted effective January 1, 2006, and activity during 2006 was as follows:

		2006 (in thousands)
Change in Benefit Obligation:		
Benefit obligation at January 1, 2006	$	4,013
Service cost		572
Interest cost		249
Actuarial (gain) loss		382

Benefits paid		(100)
Benefit obligation at December 31, 2006	$	5,116
Change in Plan Assets:		
Fair value of plan assets at January 1, 2006	$	
Actual return on plan assets		
Employer contributions		100
Benefits paid		(100)
Fair value of plan assets at December 31, 2006	$	

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Reconciliation of Funded Status:

Funded (unfunded) status of plan at December 31, 2006	$ (5,116)
Unrecognized actuarial (gain) loss	
Unrecognized prior service cost	
Unrecognized transition cost	
Accrued asset (liability) recognized at December 31, 2006	$ (5,116)

Accumulated Benefit Obligation at December 31, 2006:	$ 3,709

The following table provides certain information related to our unfunded SERP which has an accumulated benefit obligation in excess of plan assets at December 31, 2006:

	2006 (in thousands)
Projected benefit obligation	$5,116
Accumulated benefit obligation	3,709
Fair value of plan assets	

The weighted average assumptions used to determine our net periodic benefit cost for the year ended December 31, 2006 were (i) a discount rate of 5.50%; and (ii) a rate of 4.00% for increases in compensation. The components of net periodic benefit cost at December 31, 2006 were as follows:

	2006 (in thousands)
Net Periodic Benefit Cost:	
Service cost	$ 572
Interest cost	250
Amortization of prior service cost	316
Recognized net actuarial (gain) loss	8
Net periodic benefit cost	1,146
Curtailment and settlement expense	
Special termination benefit expense	
Total expense	$ 1,146

In connection with our adoption of SFAS 158, the following table summarizes amounts recognized as a component of accumulated other comprehensive income during 2006. These amounts were not previously recognized as a component of our net periodic benefit cost and will be amortized to expense during future periods. During 2007, we estimate that $0.3 million ($0.2 million net of tax) will be amortized from accumulated other comprehensive income into net periodic benefit cost.

	2006 (in thousands)
Net actuarial losses	$ 599
Prior service costs	2,920
	3,520
Tax expense (benefit)	(1,271)
Benefit obligation, net of tax	$ 2,249

As of December 31, 2006, expected contributions during 2007 are estimated at $0.1 million. Estimated future benefit payments over the next 10 years are as follows (in thousands):

2007	$ 100
2008	98
2009	142
2010	162
2011	159
2012 through 2016	$ 2,455

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Stock Compensation Plans

Stock Plans. We have four stock incentive plans (together, our Stock Plans): (i) the 1996 Stock Option Plan, which was adopted at the completion of our initial public offering in September 1996, and amended and approved by our stockholders in 1997; (ii) the 1999 Non-Qualified Stock Option Plan adopted by our Board of Directors in October 1999; (iii) the 2002 Long-Term Incentive Plan adopted in January 2002, approved by our stockholders in May 2002 and amended by our Board in October 2003; and (iv) the 2004 Long-Term Incentive Plan, approved by our stockholders in June 2004 and amended and restated by our Board in January 2006. All our employees, directors, consultants and advisors are eligible to participate in our Stock Plans, except that executive officers are not eligible to participate in the 1999 plan. The 1996, 2002 and 2004 plans allow for the granting of both incentive stock options and non-qualified stock options, and the 2002 and 2004 plans allow for the granting of restricted stock. Upon shareholder approval of the 2004 plan, all remaining options available for grant under the 2002, 1999 and 1996 plans were cancelled, and 1,500,000 shares were authorized for awards under the 2004 plan. At December 31, 2006, we had 362,877 shares authorized and available for award under the 2004 plan.

The following table summarizes all of our Stock Plans as of December 31, 2006. Pursuant to shareholder approval of the 2004 Plan, all remaining options available for grant under the 2002, 1999 and 1996 Plans were cancelled and 1,500,000 shares were made available for grant under the 2004 Plan.

	2004 Plan	2002 Plan	1999 Plan	1996 Plan	Total Plans
Options and restricted stock authorized	1,500,000	1,500,000	800,000	3,033,912	6,833,912
Options:					
Incentive stock grants		47,675		909,454	957,129
Non-qualified stock grants	943,050	1,194,000	806,606	2,132,758	5,076,414
Forfeitures	(66,090)	(115,440)	(47,905)	(40,000)	(269,435)
Cancellations		351,765	41,299	31,700	424,764
Total options	876,960	1,478,000	800,000	3,033,912	6,188,872
Restricted stock and units:					
Grants	274,039	22,000			296,039
Forfeitures	(13,496)				(13,496)
Cancellations	(380)				(380)
Total restricted stock and units	260,163	22,000			282,163
Options and restricted stock available for grant	362,877				362,877
Total exercised and issued	84,666	607,105	597,143	2,820,092	4,109,006

Immediately prior to the effective time of the pending merger with Forest (see Note 11 Subsequent Events *Pending Merger with Forest Oil Corporation*), all outstanding stock options will vest and become fully exercisable, the restrictions on all outstanding shares of restricted stock will lapse, at which time these shares will become freely transferable, and all restricted units will become fully vested and the underlying shares of our common stock will be issued to the holder. Options not exercised prior to the effective time of the merger will be cancelled (with payment

for all in-the-money options). All of our stock plans will terminate as of the effective time of the merger.
Stock Options. Options granted under our Stock Plans expire 10 years from the grant date and vest in equal annual increments over either a five-year or three-year vesting period, except that options granted to directors vest immediately upon grant. In general, stock options become fully vested upon the occurrence of a change of control (including the pending merger with Forest), unless an award agreement provides otherwise. All stock options have an exercise price equal to the closing price of our common stock as reported on the NYSE on the date of grant. After the amendment and restatement of the 2004 plan in January 2006, non-employee directors are no longer eligible to receive stock options and instead receive an annual grant of restricted stock, the number of shares of which is determined by dividing $100,000 by the closing price of our common stock on the date of our Annual Meeting of Stockholders.
Common stock issued through the exercise of non-qualified stock options results in a tax deduction for us equal to the taxable gain recognized by the optionee. Generally, we do not receive an income tax deduction for incentive stock options. For financial reporting purposes, the tax effect of this deduction is accounted for as a credit to additional paid-in-capital rather than as a reduction of income tax expense. Prior to the adoption of SFAS 123(R) on January 1, 2006, we presented tax benefits resulting from stock-based compensation as a cash flow from operating activities within our consolidated statements of cash flows. SFAS 123(R) requires excess tax benefits to be presented as a cash flow from financing

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activities. For years ended December 31, 2006, 2005 and 2004, the exercise of non-qualified stock options resulted in a tax benefit of $1.1 million, $3.5 million and $4.9 million, respectively. For 2005, the tax benefit of $3.5 million was not able to be utilized due to a tax net operating loss during 2005.

The table below sets forth a summary of options granted and outstanding, their remaining contractual lives, a weighted average exercise price and the number vested and exercisable as of December 31, 2006:

		Options Outstanding				Options Exercisable		Unvested
Range of Exercise Prices		Shares Underlying Options	Year Granted	Remaining Contractual Life	Weighted Average Exercise Price	Shares Underlying Options	Weighted Average Exercise Price	Shares Underlying Options
$13.13	$ 25.00	15,500	1997	1 years	20.72	15,500	20.72	
$15.75	$ 23.38	4,980	1998	2 years	18.97	4,980	18.97	
$16.94	$ 21.00	24,230	1999	3 years	19.53	24,230	19.53	
$18.00	$ 26.19	26,500	2000	4 years	23.69	26,500	23.69	
$22.50	$ 37.38	219,369	2001	5 years	29.13	219,368	29.13	
$27.49	$ 33.75	273,970	2002	6 years	30.13	183,670	30.12	90,300
$26.18	$ 37.42	287,540	2003	7 years	34.76	146,070	35.07	141,470
$36.56	$ 60.45	247,195	2004	8 years	56.63	106,924	57.82	140,271
$46.25	$ 66.86	305,206	2005	9 years	55.49	98,127	54.17	207,079
$50.41	$ 64.61	293,945	2006	10 years	55.15			293,945
		1,698,434			$ 43.16	825,369	$ 36.42	873,065

The following table summarizes the activity for stock options during the respective years for all of our stock plans.

	Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (1)
	(Shares)	($/Share)	(Years)	($ in thousands)
Options outstanding January 1, 2004	2,535,159	$30.23		$ 15,946
Granted	342,950	55.98		
Exercised	(873,626)	29.30		
Forfeited	(46,885)	34.49		
Options outstanding December 31, 2004	1,957,598	35.05		41,619
Granted	345,230	55.37		
Exercised	(510,316)	31.92		
Forfeited	(95,902)	40.14		
Options outstanding December 31, 2005	1,696,610	$39.85		21,971
Granted	296,370	55.37		
Exercised	(214,868)	31.92		

Forfeited	(79,678)	40.14		
Options outstanding December 31, 2006	1,698,434	$39.85	4.1	$ 14,640
Options exercisable December 31, 2006	825,369	$36.42	2.7	$ 12,676
Options available for grant December 31, 2006	362,877			

(1) The intrinsic value of an option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option, or the market price at the end of the period less the exercise price. At December 31, 2006, 2005, 2004 and 2003, the closing price per share of our common stock on the NYSE was $51.78, $52.80 and $56.31 and $36.52, respectively.

For all option grants, the grant or exercise price is equal to the closing market price on the NYSE on the date of grant. The total intrinsic value of options exercised during 2006, 2005 and 2004 was $5.5 million, $13.5 million and $15.4 million, respectively.

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Restricted Stock. Restricted stock may be granted and issued to executive officers, employees and non-employee directors as a component of each recipient s annual compensation, and vesting is generally dependent upon continued service to our company. Restricted stock carries voting and dividend rights; however, the sale or transfer of the shares is restricted. Generally, restricted shares vest and become freely transferable at the end of the vesting period, which is either five years or three years from the date of grant. In general, accelerated vesting will occur upon the occurrence of certain events, including a change of control (as defined by the plan, and which would include our proposed merger with Forest), unless an award agreement provides otherwise, and in the case of non-employee directors, termination as a director by reason of death, disability or retirement. Restricted stock awards are valued at the closing price of our common stock on the date of grant.

The table below summarizes the activity for restricted stock and units during the respective years:

	Restricted Stock and Units[1]	Weighted Average Grant Date Fair Value	Aggregate Intrinsic Value [2]
	(Shares)	($/Share)	($ in thousands)
Unvested restricted stock January 1, 2004	25,333	$ 35.44	$ 925
Granted	49,000	58.28	
Vested	(22,333)	44.29	
Forfeited			
Unvested restricted stock December 31, 2004	52,000	53.16	2,928
Granted	146,423	57.47	
Vested	(22,892)	56.64	
Forfeited	(4,317)	59.07	
Unvested restricted stock December 31, 2005	171,214	$ 56.23	9,040
Granted	78,616	55.07	
Vested	(1,440)	58.88	
Forfeited	(9,179)	58.88	
Unvested restricted stock December 31,2006	239,211	$ 55.73	$ 12,386

(1) At December 31, 2006 and 2005, includes 41,882 and 52,501 restricted units unvested and outstanding, respectively, granted in July 2005

pursuant to a retention bonus plan for certain employees at an average price of $58.76 per unit. See above discussion of the terms of our retention bonus plan.

(2) For unvested shares of restricted stock, the intrinsic value is calculated using the closing price of our common stock at the end of the period. At December 31, 2006, 2005, 2004 and 2003, the closing price per share of our common stock on the NYSE was $51.78, $52.80 and $56.31 and $36.52, respectively.

Stock Compensation Expense

On January 1, 2003, we adopted the fair value expense recognition provisions of SFAS 123, Accounting for Stock-Based Compensation, as amended, using the prospective method as defined. Accordingly, we recognized compensation expense for all stock options granted subsequent to January 1, 2003. On January 1, 2006, we adopted SFAS 123(R), Share-Based Payment. Accordingly, we now recognize compensation expense for all stock options, including the unvested portion of all grants made prior to our initial adoption of SFAS 123 on January 1, 2003. Prior period amounts have not been restated.

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Prior to adopting SFAS 123 in January 2003 and SFAS 123(R) in January 2006, we accounted for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board (APB) Opinion 25, Accounting for Stock Issued to Employees, and related interpretations. If we had accounted for all stock options using the fair value method as recommended in SFAS 123 and 123(R), compensation expense would have had the following pro forma effect on our net income and earnings per share for the years ended December 31, 2005 and 2004:

	Years Ended December 31,	
	2005	2004
	(in thousands, except per share data)	
Net income as reported	$ 105,169	$ 162,824
Add: Stock-based compensation expense included in net income, net of tax	3,292	2,581
Less: Stock-based compensation expense determined using fair value method, net of tax	4,679	4,694
Net income pro forma	$ 103,782	$ 160,711
Net income per share basic as reported	$ 3.66	$ 5.50
Net income per share diluted as reported	3.62	5.44
Net income per share basic pro forma	$ 3.62	$ 5.43
Net income per share diluted pro forma	3.57	5.37

The effects of applying SFAS 123 and the calculation of stock compensation expense in this pro forma disclosure may not be representative of future amounts.

The weighted average fair value of options granted and valuation assumptions used in the Black-Scholes option-pricing model during 2006, 2005 and 2004 were as follows:

	Years Ended December 31,		
	2006	2005	2004
Weighted average fair value of options granted	$15.02	$16.62	$21.36
Valuation assumptions:			
Risk-free interest rate	4.8%	4.1%	3.7%
Expected life or years until exercise	4	4	5
Expected stock volatility	23.6%	42.7%	37.2%
Expected dividends			

The Black-Scholes option pricing model requires the input of certain subjective assumptions, including the expected stock price volatility and expected life of the option. For the risk-free interest rate, we utilize United States treasury bills with constant maturities that correspond to the option s expected life. The expected life is based on historical exercise activity over the previous ten-year period. The expected volatility is based on historical volatility and measured using the average closing price of our stock over a 48-month period. We believe historical volatility is the most accurate measure of future volatility of our common stock. Our expected rate of forfeitures is estimated at 5% and is based on historical forfeiture rates over the previous ten-year period.

The following table provides a detail of stock compensation expenses incurred during the years ended December 31, 2006, 2005 and 2004. For 2005 and 2004, we incurred additional expense of $0.6 million and $1.6 million, respectively related to the accelerated vesting of stock options and $1.0 million and $0.8 million, respectively for the accelerated vesting of restricted stock for executive officers and members of our Board of Directors that either retired or resigned.

	2006	December 31, 2005	2004
		(in thousands)	
Options	$ 6,287	$ 4,229	$ 3,670
Restricted stock/units	3,435	2,882	1,126
Stock compensation expense, gross	9,722	7,111	4,796
Amounts capitalized	(3,265)	(2,015)	(800)
Stock compensation expense, net of amounts capitalized	$ 6,457	$ 5,096	$ 3,996

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Amounts capitalized are categorized as leasehold costs and included as a component of our natural gas and oil property balance or full cost pool. Amounts expensed are included as a component of general and administrative expense. At December 31, 2006, our unrecognized stock compensation expense related to unvested stock options to be recognized over a weighted average two-year period was approximately $7.7 million. At December 31, 2006, our unrecognized compensation expense related to restricted stock and units and expected to be recognized over a weighted average two-year period totaled $8.6 million. Amounts relating to restricted stock expense are classified as unearned compensation and included as a component of additional paid-in capital.

NOTE 5 Income Taxes

The components of our state and federal income tax provision are:

	Years Ended December 31,		
	2006	2005	2004
	(in thousands)		
Current:			
State	$ (16)	$ (258)	$ 3,411
Federal	24,668	5,593	42,681
Total current.	24,652	5,335	46,092
Deferred :			
State	6,544	1,149	3,236
Federal	16,158	56,406	47,264
Total deferred	22,702	57,555	50,500
Total income tax provision	$ 47,354	$ 62,890	$ 96,592

For the year ended December 31, 2006, we had estimated taxable income of $132.8 million, including tax deductions of $3.1 million for certain non-qualified stock options. A major component of taxable income for 2006 relates to the sale of substantially all of our Gulf of Mexico natural gas and oil properties during the first and second quarters of 2006 (see Note 10 Acquisitions and Dispositions *Sale of Texas and Louisiana Gulf of Mexico Assets*). Total taxable gains from the sales of these assets are estimated at $264 million. In addition, during 2006, we utilized all of our federal net operating loss carryforwards to partially offset taxable income in 2006, which resulted in additional alternative minimum tax credits of $6.2 million and a federal income tax receivable of $11.3 million, which was refunded in January 2007.

For the year ended December 31, 2005, we had an estimated net operating tax loss of $31.4 million, including tax deductions of $10 million for certain non-qualified stock options. During 2006, we were able to carry back this net operating loss to years 2004 and 2003 for tax refunds and additional alternative minimum tax credits. In addition, for 2005, we generated alternative minimum tax credits of $8.7 million. These tax credits can be carried forward indefinitely to offset regular income tax. At December 31, 2004, we had no net operating loss carryforwards remaining for federal income tax purposes. Net operating loss carryforwards may be used in future years to offset taxable income.

The following is a reconciliation of statutory federal income tax expense to our income tax provision:

	Years Ended December 31,		
	2006	2005	2004
	(in thousands, except rates)		

Income before income taxes	$ 115,137	$ 168,059	$ 259,416
Statutory rate	35%	35%	35%
Income tax expense computed at statutory rate	40,298	58,821	90,796
Reconciling items:			
State income taxes and other, net of federal tax benefit[1]	7,033	672	4,358
Permanent differences	23	40	45
Other adjustments[2]		1,852	
Non-deductible compensation expense		1,505	1,393
Tax provision	$ 47,354	$ 62,890	$ 96,592

(1) For 2006, includes approximately $5.4 million for Texas state margin tax implemented during 2006.

(2) For 2005, includes an adjustment relating to 2004 estimates for federal and state taxes.

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Deferred Income Taxes

Deferred income taxes primarily represent the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of our deferred taxes are detailed in the table below.

For 2006, the change in the balance of our net deferred tax liability was comprised primarily of deferred tax expense of $22.7 million, and a net decrease of $135.0 million related to tax benefits associated with the change in the fair value of open derivative contracts and post retirement benefit obligations deferred in accumulated other comprehensive income.

For 2005, the change in the balance of our deferred tax liability was comprised of deferred tax expense of $57.6 million, a tax benefit of $121.5 million due to the change in the fair value of our open derivative contracts that have been deferred in accumulated other comprehensive income, an increase in deferred tax assets for stock option deductions of $3.5 million and other adjustments of $1.1 million.

	Years Ended December 31, 2006	2005
	(in thousands)	
Deferred tax assets:		
Derivative instruments	$ 10,446	$ 146,716
Future post retirement benefit obligation	1,271	
Ineffectiveness derivative instruments		1,135
Net operating loss	979	11,101
Alternative minimum tax credit carryforwards	2,961	8,728
Deferred compensation	9,192	5,728
Total gross deferred tax assets	24,849	173,408
Deferred tax liabilities:		
Oil and gas property and equipment	377,367	368,788
Ineffectiveness of derivative instruments	560	
Total gross deferred tax liabilities	377,927	368,788
Net deferred tax liability	$ 353,078	$ 195,380
Reflected in the accompanying Balance Sheet as:		
Current deferred income tax asset	$ (10,244)	$ (145,922)
Non-current deferred income tax liability	363,322	341,302
	$ 353,078	$ 195,380

NOTE 6 Related Party Transactions

Transactions with our Executive Officers and Directors

Employment Agreements

We have entered into employment agreements with all of our executive officers. These agreements have an initial term of three years, which is automatically extended each year for an additional year on the anniversary effective date, unless either party gives notice to the contrary within 90 days prior to the anniversary of the effective date. Executive officers receive annual salary and bonus payments pursuant to their employment agreements which are subject to review each year by our Compensation Committee. Payment of the bonus is based on achievement of certain performance goals established each year by our Compensation Committee. In addition, executive officers are eligible to participate in our stock compensation, deferred compensation and supplemental executive pension plans.

If we terminate the employment of an executive without cause (as defined in the agreement), or if the executive terminates his employment with us for good reason (as defined in the agreement, which includes the occurrence of certain events following a change in control, including the pending merger with Forest (see Note 11 Subsequent Events *Pending Merger With Forest Oil Corporation*)), we are obligated to pay the executive a lump-sum severance payment equal to 2.99 times his or her then current annual rate of total compensation, and to continue certain medical and insurance benefits for a specified time period. Total compensation is defined to include salary, targeted bonus and car allowance. The agreements further provide

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that if any payments made to the executive, whether or not under the agreement, would result in an excise tax being imposed on the executive under Section 4999 of the Internal Revenue Code on excess parachute payments, we will make each of the executives whole on a net after-tax basis.

We may terminate an executive's employment for cause without financial obligation (other than payment of any accrued obligations). Each executive may terminate his or her employment at any time for any reasons. In the event the executive s employment is terminated by us without cause or upon death or disability, or if the executive terminates his employment with us for good reason, any unvested shares of restricted stock, unvested options or similar deferred compensation automatically will vest and any other conditions to such awards shall be deemed satisfied.

In October 2006, we amended the employments agreements with each of our executive officers to comply with Section 409A of the Internal Revenue Code, and any regulations and/or guidance promulgated thereunder (collectively, Section 409A). The purpose of the amendments generally was to avoid the imposition of certain taxes and penalties under Section 409A relating to certain non-qualified deferred compensation payments (within the meaning of Section 409A) payable upon an executive s separation from a company by imposing, where necessary, a six-month delay upon the commencement of such payments following separation from service. In addition, the amendments provided that interest will be payable by us in the event of a delay in payments necessitated by Section 409A.

The merger agreement dated January 7, 2007 with Forest (see Note 11 Subsequent Events *Pending Merger With Forest Oil Corporation*) permits us to amend each of the employment agreements with our executive officers to provide for a transitional period of 60 days following the effective time of the merger. Pursuant to such amendment, the executive would agree not to assert that he or she has good reason to terminate employment and to remain employed for 60 days following the effective time of the merger. In exchange, we would agree that (a) the executive will continue to be paid base salary during such transitional period at the rate in effect immediately prior to the effective time of the merger, (b) unless otherwise agreed in writing with the executive, the executive s employment will terminate on the last day of such 60-day transitional period and (c) such termination (or any earlier termination by the employer without cause or due to the executive s death or disability) will be deemed to be a termination by the employer without cause for all purposes under the employment agreement. As of the date of this Annual Report, all of our executives have signed amendments to their employment agreements as described above.

Pursuant to the merger agreement with Forest and to the extent required in our employment agreements, Forest has agreed to assume and perform each of the employment agreements as of the effective time of the merger.

Employment Agreements with Robert T. Ray, Chief Financial Officer, and Carolyn M. Campbell, Senior Vice President and General Counsel.

On January 18, 2006, we entered into an employment agreement with Robert T. Ray in connection with Mr. Ray s appointment as Senior Vice President and Chief Financial Officer of our company and, on March 27, 2006, we entered into an employment agreement with Carolyn M. Campbell in connection with Ms. Campbell s appointment as Senior Vice President and General Counsel of our company. The terms of Mr. Ray s and Ms. Campbell s employment agreements are consistent with the general terms described above. Further, Mr. Ray s agreement provided for an initial annual base salary of $315,000 and an annual target incentive bonus equal to 55% of his base salary upon the achievement of pre-established performance goals. Ms. Campbell s agreement provided for an initial annual base salary of $275,000 and an annual target incentive bonus equal to 55% of her salary upon the achievement of pre-established performance goals. In addition, Mr. Ray received a signing bonus in the amount of $85,000, together with 7,500 restricted shares of our common stock and options to purchase 20,000 shares of our common stock at $53.72 per share. Ms. Campbell received 5,000 restricted shares of our common stock and options to purchase 15,000 shares of our common stock at an exercise price of $50.41 per share. The agreements provide for an automobile allowance of $700 per month and reimbursement of certain business expenses and require us to provide certain disability and life insurance. If Mr. Ray or Ms. Campbell is terminated without cause, or if either terminates their employment with us for good reason, we are obligated to pay each a lump sum severance payment as described above. Based on compensation levels at year-end 2006, Mr. Ray s lump sum payment would equal approximately $1.7 million and Ms. Campbell s would equal approximately $1.4 million.

Amendments to Employment Agreements 2005

In February 2005, we entered into amended and restated employment agreements with William G. Hargett, our President and Chief Executive Officer, Steven L. Mueller, our Executive Vice President and Chief Operating Officer, John H.

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Karnes, our then Senior Vice President and Chief Financial Officer, James F. Westmoreland, our Vice President and Chief Accounting Officer, and Roger B. Rice, our Senior Vice President-Administration.

By entering into the amended and restated employment agreements and terminating their prior employment agreements with us, Messrs. Hargett, Mueller, Karnes, Westmoreland and Rice gave up certain rights, including the right to receive severance for a termination of employment following a change of control of our company absent the existence of good reason and the right to guaranteed annual stock option grants and incentive compensation bonuses, which will now be subject to the discretion of our Compensation and Management Development Committee. In addition to these rights, Mr. Hargett also gave up the right to receive a transaction bonus upon the occurrence of certain corporate transactions involving our company, and all of the executives are agreeing to somewhat broader non-competition provisions under the amended and restated agreements. In consideration of their entering into the amended and restated agreements and foregoing such rights, we paid to each of these executives cash and/or restricted stock as follows: for Mr. Hargett, $4.2 million; for Mr. Mueller, $0.4 million in cash and 6,553 shares of restricted stock; for Mr. Karnes, 12,892 shares of restricted stock; for Mr. Westmoreland, $0.3 million in cash and 5,394 shares of restricted stock; and for Mr. Rice, $0.3 million in cash and 5,266 shares of restricted stock. The restricted stock vests over a period of five years in accordance with the terms of our Amended and Restated 2004 Long-Term Incentive Compensation Plan.

Lump-Sum Payments to Executives Under Employment Contracts 2005 and 2004

On December 8, 2005, we terminated our employment agreement with John H. Karnes, who resigned as Senior Vice President and Chief Financial Officer, and entered into a separation agreement and general release with Mr. Karnes. The separation agreement provided for full settlement of any compensation and benefits to which Mr. Karnes would otherwise be entitled under his employment agreement. Mr. Karnes received a cash lump-sum severance payment of $1.5 million and was entitled to receive certain welfare benefits at our expense for a specified period following termination of employment. In addition, we incurred $1.7 million in stock compensation expense pursuant to the accelerated vesting of Mr. Karnes restricted stock and stock options.

Pursuant to a management organizational change made within our company in November 2004 that changed the reporting responsibilities of three executive officers, Charles W. Adcock, Senior Vice President and General Manager Offshore Division, resigned effective December 14, 2004, and Timothy R. Lindsey, Senior Vice President of Exploration, and Tracy Price, Senior Vice President Land, resigned effective March 1, 2005. Pursuant to their resignations and the termination of their employment agreements with our company, during the fourth quarter of 2004, we incurred approximately $5.1 million in general and administrative expense of which $1.3 million, $1.1 million and $1.0 million, respectively, related to lump-sum severance entitlements for Messrs. Adcock, Lindsey and Price and, $1.7 million related to expense incurred as a result of the accelerated vesting of all their outstanding stock options and restricted stock.

Transactions Involving Companies with Common Directors

John U. Clarke, a member of our Board of Directors and Chairman of the Audit Committee, serves as a Chairman and Chief Executive Officer of NATCO Group, a publicly traded oil field services and equipment company. During 2006, 2005 and 2004, we purchased services and supplies from NATCO of approximately $1.0 million, $1.3 million and $0.9 million, respectively. Mr. Clarke meets all requirements of the New York Stock Exchange to be considered an independent director of our company.

Transactions with KeySpan

To facilitate the KeySpan Exchange (see Note 3 *KeySpan Exchange and Offering*), we entered into a Distribution Agreement with KeySpan that defines each company s rights and obligations with respect to the exchange transaction. The Distribution Agreement contains, among other provisions, customary representations and warranties concerning our Appalachian Basin properties, including title, regulatory compliance and environmental matters, along with limited indemnification obligations. Pursuant to the Distribution Agreement, the two companies also entered into a Tax Matters Agreement, which generally provides that each party would be responsible for its own tax consequences if the KeySpan Exchange fails to qualify as a tax-free transaction. In addition, we entered into a Transition Services

Agreement pursuant to which we provided KeySpan with transitional services with respect to the Appalachian Basin assets for a fee of $27,000 per month until March 31, 2005.

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NOTE 7 Derivative Instruments

At of December 31, 2006, we had entered into commodity price derivative contracts with respect to approximately 10% of our forecasted natural gas production for 2007 and less than 5% of our forecasted natural gas production for 2008, as listed in the following table. The total estimated fair value of our natural gas derivative instruments at December 31, 2006 was a liability of $27.4 million. During the first quarter of 2006, our open derivative contracts ceased to qualify for hedge accounting due to the combination of factors, including the loss of correlation with the NYMEX price for certain contracts caused in part by the residual effects of Hurricanes Katrina and Rita during the first three months of 2006 and our entry into a definitive purchase and sale agreement to sell the Texas portion of our Gulf of Mexico assets in February 2006. At December 31, 2006, an unrealized loss of $18.5 million, net of tax, remains deferred in accumulated other comprehensive income. This loss represents the fixed value of our remaining open derivative contracts deferred in accumulated other comprehensive income at the time they ceased to qualify for hedge accounting. Over the next 12-month period and at the time when sale of the related natural gas production occurs, we expect to reclassify from accumulated other comprehensive income to earnings a net loss of $11.1 million, net of tax, leaving $7.4 million to be recognized during 2008.

During 2006, our total loss from hedging activities was $64.5 million, which included a realized loss of $69.2 million on contracts settled during the period and a net unrealized gain of $4.7 million. The unrealized gain of $4.7 million was comprised of (i) a mark-to-market gain of $37.7 million for changes in the fair value of our open contracts subsequent our loss of hedge accounting; (ii) a gain of $45.9 million on the recapture of prior ineffectiveness; (iii) recognition of a loss of $20.6 million deferred in accumulated other comprehensive income at December 31, 2005 as a result of offshore production curtailments during the fourth quarter of 2005 resulting from damage to Gulf of Mexico infrastructure after Hurricanes Katrina and Rita; and (iv) a loss of $58.2 million representing amounts previously deferred in accumulated other comprehensive income allocated to production from Gulf of Mexico assets that were sold during the year.

Natural Gas Derivatives at December 31, 2006	**Fixed Price Swaps**		**Collars**			**December 31, 2006**
	Daily	**NYMEX**	**Daily**	**NYMEX**		
Period	**Volume (MMBtu)**	**Contract Price**	**Volume (MMBtu)**	**Contract Price Floor**	**Ceiling**	**Fair Value (thousands)**
January December 2007			30,000	$ 5.000	$ 6.597	$ (10,151)
January December 2008			20,000	5.000	5.720	(17,247)
						$ (27,398)

In connection with the completion of the divestiture of our Gulf of Mexico assets on June 1, 2006, we were required under our revolving credit facility to liquidate a portion of our 2006 hedge position. In order to comply with this requirement, in June 2006, we liquidated and settled open contracts covering 60,000 MMBtu per day of hedged production for each of the months July through December 2006. The cost to liquidate and settle these contracts was approximately $14.3 million. In addition, on August 4, 2006, we liquidated and settled open derivative contracts representing 20,000 MMBtu per day of hedged production for each of the months September and October 2006. The cost to liquidate and settle these contracts was approximately $0.9 million.

At of December 31, 2005, we had entered into commodity price derivative contracts with respect to approximately 75% of our forecasted natural gas production for 2006 and less than 10% of our forecasted natural gas production for 2007 and 2008 as listed in the table below. The total estimated fair value of our natural gas and oil derivative instruments at December 31, 2005 was a liability of $417.7 million, of which we had deferred a net loss of $267.7 million in accumulated other comprehensive income and recognized $46.0 million in earnings as a reduction to natural gas and oil revenues as a result of the estimated ineffectiveness of our open contracts as of the end of the period. In addition, during the fourth quarter of 2005, we recognized in income a gain of $26.1 million for NYMEX based derivative contracts that hedged production allocated to the Houston Ship Channel index due to loss of correlation between the NYMEX price and the Houston Ship Channel index. Further, we deferred a loss in accumulated other comprehensive income of $20.6 million as a result of a production shortfall during the fourth quarter of 2005 due to offshore production curtailments caused by Hurricanes Katrina and Rita, which deferred loss was reclassified to earnings during the first quarter of 2006, as we determined that due to continued delays in the restoration of third party pipelines and processing facilities to pre-hurricane capacity, production from certain of our offshore fields would not occur in accordance with our internal forecasts. Finally, during 2005, we realized a loss of $265.2 million on contracts settled during the period.

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Natural Gas Derivatives at December 31, 2005	Fixed Price Swaps		Collars			December 31, 2005
	Daily	NYMEX	Daily	NYMEX		
Period	Volume (MMBtu)	Contract Price	Volume (MMBtu)	Contract Price Floor	Contract Price Ceiling	Fair Value (thousands)
January December 2006	30,000	$ 5.893	220,000	$ 5.774	$ 7.090	$ (352,456)
January December 2007			30,000	5.000	6.597	(40,255)
January December 2008			20,000	5.000	5.720	(24,947)
						$ (417,658)

From time to time, if the fair value of an open contract or contracts exceeds our available credit limit with a particular counterparty, we could be required to post a letter of credit to further guarantee our performance. As of December 31, 2006 and 2005, we did not have any outstanding letters of credit issued relating to derivative contracts.

Fair market value is calculated for the respective months using prices derived from NYMEX futures contract prices existing at December 31st and from market quotes received from counterparties.

For natural gas, transactions are settled based upon the NYMEX price on the final trading day of the month (the settlement price). With respect to any particular swap transaction, the counterparty is required to make a payment to us in the event that the settlement price for any settlement period is less than the swap price for the transaction, and we are required to make payment to the counterparty in the event that the settlement price for any settlement period is greater than the swap price for the transaction. For any particular collar transaction, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price for the transaction, and we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price for the transaction. We are not required to make or receive any payment in connection with a collar transaction if the settlement price is between the floor and the ceiling.

NOTE 8 Sales to Major Customers

We sold natural gas and oil production representing 10% or more of our natural gas and oil revenues for the years ended December 31, 2006, 2005 and 2004 as listed below. In the exploration, development and production business, production is normally sold to relatively few customers. However, based on the current demand for natural gas and oil, we believe that the loss of any of our major purchasers would not have a material adverse effect on our operations. Amounts presented in the below table that are less than 10% have been included for information and comparison purposed only.

Major Purchaser	For the Year Ended December 31, 2006	2005	2004
Oneok	11.9%	8.8%	8.0%
ConocoPhillips	11.7%	11.9%	11.9%
Kinder Morgan	11.3%	8.5%	10.1%
Anadarko Petroleum Corporation	6.1%	10.1%	9.1%

NOTE 9 Commitments and Contingencies

Legal Proceedings

On June 22, 2006, the City of Monroe Employees Retirement System filed a purported class action lawsuit in the District Court of Harris County, Texas, on behalf of itself and all of the company s other public shareholders, against the company and its directors. The plaintiff alleges that the defendants breached their fiduciary duties of loyalty and due care to the class in connection with our response to an unsolicited proposal by JANA Partners LLC to purchase the company. The plaintiff subsequently amended its petition as a derivative claim and requested that the court order the defendants to comply with their fiduciary duties, respond in good faith to potential offers, and establish a committee of independent directors to evaluate strategic alternatives and take decisive steps to maximize shareholder value. The plaintiff also seeks to invalidate our shareholder rights plan or require the defendants to rescind or redeem such plan. Finally, the plaintiff seeks compensatory and punitive damages, as well as attorneys and experts fees. In October 2006, the judge denied the defendants motion to abate or special exceptions. Although this ruling allows the plaintiff s claim to survive beyond the

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pleadings stage, it has no bearing on the merits of the case. In January 2007 and following our entry into the merger agreement with Forest, the plaintiff further amended its petition, adding a new class-action claim challenging the strategic alternatives review process conducted by us and the adequacy of the merger consideration agreed upon in the merger agreement, and naming Forest as a defendant. The plaintiff also seeks to enjoin the merger, asserting that our directors decision to enter into the merger with Forest constitutes a breach of fiduciary duties. We believe this lawsuit is without merit, and we intend to vigorously defend against it. Although it is too soon to predict the outcome of this lawsuit or the time to resolution, we do not believe that it will have a material adverse effect on our financial position, results of operations or cash flows.

In addition to the foregoing, we are involved from time to time in various other claims and legal or governmental proceedings incidental to our business. In the opinion of management, the ultimate liability, if any, associated with these matters is not expected to have a material adverse effect on our financial position, results of operations or cash flows.

Severance Tax Refund

During July 2002, we applied for and received from the Railroad Commission of Texas a high-cost/tight-gas formation designation for a portion of our South Texas production. For qualifying wells, production is either exempt from tax or taxed at a reduced rate until certain capital costs are recovered. For the years ended December 31, 2006, 2005 and 2004, we recognized as other, non-operating income refunds of prior period severance tax payments of $7.7 million, $2.7 million and $1.2 million, respectively. At December 31, 2006 and 2005, our current receivables include $2.0 million and $0.7 million, respectively, in gross refunds, of which we estimate approximately 70%, or $1.4 million and $0.5 million, respectively, relate to our net revenue interest. Beginning September 1, 2003, all refunds issued by the State of Texas are to be made in the form of a reduction to or credit against our current severance tax liability rather than in the form of a cash reimbursement.

Operating Leases

We have entered into non-cancelable operating lease agreements in the ordinary course of our business activities. These leases include those for our office space at 1100 Louisiana in Houston, Texas and at 700 17th Street in Denver, Colorado together with various types of office equipment (primarily copiers and fax machines). The terms of these agreements have various expiration dates from 2007 through 2010. Rental expense related to these leases was $2.3 million, $1.9 million and $1.6 million, respectively, for the years ended December 31, 2006, 2005 and 2004. At December 31, 2006, our total commitment under these non-cancelable operating leases was approximately $5.0 million. Minimum rental commitments under the terms of our operating leases are as follows:

Years Ended December 31,	**Minimum Payments**
	(in thousands)
2007	$ 1,913
2008	1,924
2009	1,137
2010	23
Thereafter	
Total	$ 4,997

Letters of Credit

We had $0.3 million in letters of credit outstanding at December 31, 2006 and at December 31, 2005.

North Dakota Lease Acquisition

On December 1, 2006, we entered into a purchase and sale agreement to acquire natural gas and oil leases in the Williston Basin of North Dakota for $3.9 million. Upon entering the agreement, we paid a performance deposit of approximately $0.1 million. At December 31, 2006 and under the terms of the agreement, we are obligated for up to an estimated $3.8 million for the remaining portion of the purchase price.

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Drilling Contracts

During 2006, we entered into three long-term contracts for the exclusive use of drilling rigs for periods of greater than or equal to 12 months. These include a one-year contract for a drilling rig in East Texas; a two-year contract for a rig in the Uinta Basin; and a one-year contract for a rig in South Texas. At December 31, 2006 and under these contracts, we are obligated for up to an estimated $8.7 million in fees for use of the rigs during the remaining terms of the contracts.

Seismic Contracts

In October 2006, we entered into an agreement to acquire seismic data covering various acreage positions in Colorado. At December 31, 2006 and under the terms of the agreement, we are obligated for up to an estimated $1.5 million in future fees.

NOTE 10 Acquisitions and Dispositions (Reserve quantities, wells, acreage and working interests included below are unaudited.)

2006 Acquisitions and Dispositions

East Texas Acquisition. On April 25, 2006, we completed the acquisition of certain interests in natural gas and oil producing properties and acreage in the Willow Springs Field of Gregg County, located in East Texas, from Samson Lone Star Limited Partnership. The $22 million cash purchase price was reduced by $0.7 million to $21.3 million for various customary closing items, including an adjustment for operations related to the properties after the effective date of the transaction, January 1, 2006. The properties cover approximately 4,237 gross (3,579 net) acres, are adjacent to our existing operations in the Willow Springs Field and include interests in 28 producing wells with an average working interest of 80%. Based on internal estimates, total proved reserves associated with the interests acquired were 16.2 Bcfe as of January 1, 2006. The acquisition was funded with cash on hand of $19.1 million and borrowings under our revolving credit facility of $2.2 million.

South Texas Acquisition. On December 13, 2006, we acquired, a 100% working interest in 10 producing wells located in Webb County, Texas, from Legend Natural Gas II, LP. The $4.3 million purchase price was paid with cash on hand. The acquired properties cover approximately 3,000 acres and are located in close proximity to our producing assets in the South Laredo Field. Based on internal estimates, total proved reserves associated with the interests acquired were approximately 1.8 Bcfe.

DJ Basin Acquisition. On December 14, 2006, we completed the acquisition of certain interests in natural gas and oil producing properties together with developed and undeveloped acreage, located along the Niobrara trend in the DJ Basin of Eastern Colorado and Western Nebraska, from Santos TOG Corp. (formerly known as Tipperary Oil & Gas Corporation). The net purchase price of $21.4 million was paid with cash on hand. The acquired properties and acreage cover approximately 145,000 net acres and include interests in approximately 305 wells. The majority of the interests acquired were incremental working interests of ranging between 20% and 25% in wells operated by us. Based on internal estimates, total proved reserves associated with the interests acquired were approximately 14.2 Bcfe at November 1, 2006, and daily production averaged 1 Mcfe per day, net to the interests acquired.

Sale of Texas Gulf of Mexico Assets. On March 31, 2006, we completed the sale of the Texas portion of our Gulf of Mexico assets. Pursuant to the purchase and sale agreement dated February 28, 2006 between us, as seller, and various partnerships affiliated with Merit Energy Company, as buyer, the gross sale price was $220 million. The net cash proceeds received from the sale of these assets totaled approximately $190.8 million after various customary closing items, including the adjustment for operations related to the properties after January 1, 2006, the effective date of the transactions. Of the total net proceeds, approximately $140.1 million was received for assets acquired by various partnerships affiliated with Merit Energy Company. In addition, approximately $43.1 million and $7.6 million were received from Hydro Gulf of Mexico, L.L.C. and Nippon Oil Exploration U.S.A. Ltd., respectively, pursuant to the exercise of their preferential rights to acquire certain working interests offered for sale. The Texas portion of our Gulf of Mexico assets accounted for approximately 18% of our 2005 production and represented an estimated 58.5 Bcfe, or 7% of our total proved reserves at December 31, 2005. Of the $190.8 million in net cash proceeds received from the sale of our Texas Gulf of Mexico assets, we used $158 million to repay and reduce outstanding borrowings under our revolving credit facility, deposited $9.5 million with a qualified intermediary for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code, and used substantially all of the $23.3 million balance for working capital purposes. In

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accordance with full cost accounting, no gain or loss was recognized on the sale. The net proceeds of $190.8 million were recorded as a reduction to the full cost pool.

Sale of Louisiana Gulf of Mexico Assets. On June 1, 2006, we completed the sale of substantially all of our Louisiana Gulf of Mexico assets for a gross sale price of $590 million. The sale of a substantial majority of these assets to various partnerships affiliated with Merit Energy Company was completed on May 31, 2006 pursuant to a purchase and sale agreement dated April 7, 2006, and the sale of certain working interests to Nippon Oil Exploration U.S.A. Ltd. and Chevron USA Inc. was completed on June 1, 2006 pursuant to the exercise of preferential purchase rights. The aggregate net cash proceeds received from the sale of these assets totaled approximately $530.8 million after customary closing items, including the preliminary adjustment for operations related to the properties after January 1, 2006, the effective date of the transactions. Of the total net proceeds, approximately $510.2 million was received from various partnerships affiliated with Merit Energy Company, and approximately $16.6 million and $4.0 million was received from Nippon Oil Exploration U.S.A. Ltd. and Chevron USA Inc., respectively.

At December 31, 2005, proved reserves associated with these assets were estimated at 186.1 Bcfe, and production associated with these assets accounted for approximately 22% of our 2005 production and 27% of our production during the first six months of 2006. The sale transactions did not include 18 Louisiana offshore blocks retained by us. Of these 18 blocks, four expired subsequent to the sales transactions, two were drilled during 2006, resulting in two successful exploratory wells, and 12 remain classified as undeveloped at the end of 2006.

Of the $530.8 million in net cash proceeds received from the sale of the Louisiana portion of our Gulf of Mexico assets, $314.2 million was deposited directly with qualified intermediaries for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code, and substantially all of the $216.6 million balance, associated with properties sold outside the like-kind exchange arrangement, was used to reduce outstanding borrowings under our revolving credit facility. In accordance with full cost accounting, no gain or loss was recognized on the sale. The net proceeds of $530.8 million were recorded as a reduction to the full cost pool.

The sale of certain of our Gulf of Mexico properties accelerated the payment of a net profits interest to the predecessor owner of properties acquired by us in October 2003, for which we paid approximately $21.0 million during August 2006. The payment was accounted for as a purchase price adjustment in connection with the original acquisition of the properties and recorded as an addition to natural gas and oil properties.

2005 Acquisitions

Kerr-McGee South Texas Acquisition. On November 30, 2005, we completed the acquisition of certain interests in natural gas and oil producing properties and undeveloped acreage in four fields located in South Texas from Kerr-McGee Oil & Gas Onshore LP and Westport Oil and Gas Company, L.P. The net purchase price of $159.0 million was paid in cash and financed by borrowings under our bank credit facility. The $163.0 million purchase price was reduced by $4.0 million for various customary closing items, including revenues received by and expenditures made by the seller related to the properties acquired for the period between the effective date of the transaction, October 1, 2005, and the closing date, November 30, 2005.

The properties cover approximately 26,000 net acres, include approximately 300 wells and are located in the Rincon Field in Starr County, the Tijerina-Canales-Blucher Field in Jim Wells and Kleberg Counties, the Vaquillas Ranch Field in Webb County, and the San Carlos Field in Hidalgo County. At December 31, 2005, proved reserves were approximately 62 Bcfe, of which approximately 75% were natural gas. Current production from the four fields is estimated at approximately 10 MMcfe/day, net to the interests acquired. We operate 100% percent of the proved reserves with an average working interest of 60%.

Dale East Texas Acquisitions. On March 15, 2005, we completed the purchase of certain natural gas and oil producing properties and associated gathering pipelines and equipment, together with developed and undeveloped acreage, located in Rusk County, Texas, from Dale Gas Partners L.P. The $22.0 million purchase price was paid in cash and financed by borrowings under our bank credit facility. The properties purchased cover approximately 5,776 gross acres located in South Oak Hill Field, which is in close proximity to our existing operations in the Willow Springs Field, and represent interests in three producing wells and one well in the completion stage. We operate all of the

wells acquired, and our working interest is 100%. Based on internal estimates, total proved reserves associated with the interests acquired were 9.1 Bcfe as of March 15, 2005, the effective date of the transaction.
On April 5, 2005, we completed the acquisition of a 50% working interest in seven producing wells together with undeveloped acreage located in the North Blocker Field located in Harrison County, Texas from Dale Resources East Texas L.L.C. The $9.2 million purchase price was paid in cash and financed by borrowings under our bank credit facility. The

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properties purchased cover approximately 4,679 gross acres, and we operate all seven wells. Based on internal estimates, total proved reserves associated with the interests acquired were estimated at 7.7 Bcfe, as of April 1, 2005, the effective date of the transaction. On December 31, 2005, we purchased the remaining working interests held by Dale in the seven wells and undeveloped acreage acquired in April 2005 for $7.3 million.

2004 Acquisitions and Dispositions

Orca Acquisition. On October 29, 2004, we completed the acquisition of certain producing properties from Orca Energy, L.P. The $113.6 purchase price was paid in cash and financed by borrowings under our bank credit facility. The transaction was effective August 1, 2004. The Orca properties consist of 10 offshore blocks and two onshore fields. The onshore fields are non-operated and located in central Mississippi, the Wausau Field, located in Wayne County and the Oakvale Dome Field, located in Jefferson Davis County. The 10 offshore blocks are a mix of state and federal leases, located in less than 50 feet of water, and include seven blocks in federal waters and three blocks in state waters. Total acreage acquired covers 23,777 gross (17,973 net) acres. The properties include 15 platforms, five production caissons and 28 producing wells. Based on internal estimates, total proved reserves acquired were approximately 60.7 Bcfe as of the closing date, October 29, 2004, of which 81% were natural gas. Our average working interest in the properties acquired is 68%, and we operate approximately 85% of the proved reserves acquired.

BP Acquisition. On September 30, 2004, we completed the purchase of two producing offshore fields from BP Exploration & Production Inc. The net purchase price of $30.0 million was paid in cash and financed by borrowings under our bank credit facility. The $31.5 million purchase price was reduced by $1.5 million for various customary closing items, including revenues received by and expenditures made by the seller related to the properties acquired for the period between the effective date of the transaction, August 1, 2004, and the closing date, September 30, 2004. The properties acquired are located at Eugene Island 240 and Main Pass 264 and each block has one producing platform. Based on internal estimates, total proved reserves associated with the interests acquired were approximately 16.2 Bcfe as of September 30, 2004, of which 85% were natural gas. Our average working interest is 85%, and we operate both blocks.

Disposition and Exchange of Appalachian Basin Assets. In connection with the KeySpan Exchange on June 2, 2004 (see Note 3 KeySpan Exchange and Offering), we divested all of our Appalachian Basin assets with an agreed upon value of $60 million. Pursuant to an Asset Contribution Agreement, we contributed to Seneca-Upshur all of the assets relating solely to our Appalachian Basin assets that were not already owned by Seneca-Upshur, and Seneca-Upshur assumed all of the liabilities relating to the Appalachian Basin assets for which it was not already liable. In the KeySpan Exchange, all of the stock of Seneca-Upshur was then conveyed to KeySpan and effective June 1, 2004, Seneca-Upshur became an indirect wholly-owned subsidiary of KeySpan.

Our Appalachian property base was located primarily in central West Virginia and included the Belington, Clarksburg and Seneca Upshur Fields located in Barbour, Randolph, Upshur and Mingo Counties of West Virginia. Included in the assets exchanged were the assets acquired on December 31, 2003, from EnerVest East Limited Partnership located adjacent to our existing base in the Crawford and Pennsboro Fields in Lewis, Harrison, Tyler and Ritchie Counties of West Virginia and the Waynesburg and Yatesboro Fields in Greene and Armstrong Counties of southwestern Pennsylvania. Based on internal estimates at June 1, 2004, our Appalachian Basin properties had 51.2 Bcfe of estimated proved reserves, and our average daily production was approximately 8 MMcfe/day, which represented approximately 3% of our total daily production. We had approximately 207,000 gross (129,000 net) acres under lease and owned working interests in approximately 1,414 gross (1,035 net) wells, of which we operated approximately 92%. Our average working interest was 73%.

Sale of Onshore South Louisiana Properties. On February 4, 2004, we completed the sale of our onshore South Louisiana producing properties. The sale was effective November 1, 2003, and the properties represented 12.3 Bcfe proved reserves as of December 31, 2003, and included interests in 33 gross (9.5 net) producing wells and covered approximately 6,300 gross (2,300 net) acres. The sale price of $15 million was reduced by $1.9 million for various customary closing items, including revenues received by and expenditures made by us related to the properties sold for the period between the effective date of the transaction and the closing date. The net proceeds of $13.1 million from the sale were used to repay borrowings under our bank credit facility.

NOTE 11 Subsequent Events

Pending Merger Agreement with Forest Oil Corporation

On January 7, 2007, we announced the conclusion to the strategic alternatives review process with our entry into an agreement and plan of merger with Forest Oil Corporation. Under the merger agreement, Forest will acquire all of the outstanding shares of Houston Exploration for a combination of cash and Forest common stock. Under the terms of the

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merger agreement, our shareholders will receive total consideration equal to 0.84 shares of Forest common stock and $26.25 in cash for each outstanding share of Houston Exploration common stock, or an aggregate of an estimated 23.6 million shares of Forest common stock and cash of $740 million. Based on the closing price of Forest common stock on January 5, 2007, the last trading day prior to announcement of the transaction, this represents $52.47 per share of merger consideration to be received by Houston Exploration shareholders. The actual value of the merger consideration to be received by our shareholders will depend on the average closing price of Forest common stock for the ten trading days ending three calendar days prior to the effective date of the merger, and the amount of cash and stock consideration will be determined by shareholder elections, subject to proration and an equalization formula. It is anticipated that the stock portion of the consideration will be tax free to Houston Exploration shareholders.

The Boards of Directors of Houston Exploration and Forest each unanimously approved the proposed merger. The merger is subject customary terms and conditions, including the approval of both Houston Exploration and Forest shareholders, and is expected to be completed in the second quarter of 2007. Upon completion of the transaction, it is anticipated that Forest shareholders would own approximately 73% of the combined company, and Houston Exploration shareholders would own approximately 27%.

Concurrently with the execution of the merger agreement, funds affiliated with JANA Partners entered into a voting agreement with Forest pursuant to which the JANA funds agreed, during the term of the voting agreement, to vote their shares of our common stock in favor of the merger with Forest and the adoption of the merger agreement and against any transaction that would impede or delay the merger with Forest, and granted to Forest a proxy to vote their shares at any stockholder meeting convened to consider such matters. As of January 7, 2007, the JANA funds beneficially owned approximately 14.7% of our total issued and outstanding shares of our common stock. The voting agreement will terminate in certain instances, including an adverse recommendation change (as defined in the merger agreement) by our Board of Directors or any material amendment to the merger agreement that is adverse to us or our stockholders.

On February 8, 2007, Forest filed a registration statement on Form S-4 with the SEC, including a preliminary joint proxy statement / prospectus with respect to the merger. Also on February 8, 2007, the companies received notice of early termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvement Act with respect to the proposed transaction.

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NOTE 12 Supplemental Information on Natural Gas and Oil Exploration, Development and Production Activities (Unaudited)

The following information concerning our natural gas and oil operations has been provided pursuant to Statement of Financial Accounting Standards No. 69, Disclosures about Oil and Gas Producing Activities. Our natural gas and oil producing activities are conducted onshore within the continental United States and offshore in federal and state waters of the Gulf of Mexico.

Capitalized Costs of Natural Gas and Oil Properties

	As of December 31,		
	2006	2005	2004
		(in thousands)	
Unevaluated properties, not subject to amortization	$ 28,317	$ 107,146	$ 122,691
Properties subject to amortization [1]	3,478,878	3,556,755	2,777,097
Capitalized costs	3,507,195	3,663,901	2,899,788
Accumulated depreciation, depletion and amortization	(1,920,494)	(1,649,674)	(1,355,857)
Net capitalized costs	$ 1,586,701	$ 2,014,227	$ 1,543,931

(1) Includes asset retirement obligations of $43.6 million, $93.8 million and $71.2 million, respectively, for the years ended December 31, 2006, 2005 and 2004.

Additions to Unevaluated Properties

The following table provides a summary of unevaluated costs not being amortized as of December 31, 2006, by the year in which the costs were incurred. There are no individually significant properties or significant development projects included in our unevaluated property balance. We estimate that costs will be evaluated and transferred within four years.

	Costs incurred by Year as of December 31, 2006				
	Total	2006	2005	2004	2003 and Prior
			(in thousands)		
Property acquisition costs	$ 17,393	$ 1,008	$ 11,426	$ 4,495	$ 464
Exploration and development	10,924	10,078	603	224	19

Total	$ 28,317	$ 11,086	$ 12,029	$ 4,719	$ 483

Capitalized Costs Incurred

Costs incurred for natural gas and oil exploration, development and acquisition are summarized below. Costs incurred during the years ended December 31, 2006, 2005 and 2004 include interest expense and general and administrative costs directly related to acquisition, exploration and development of natural gas and oil properties of $24.8 million, $25.6 million and $23.2 million, respectively. During the years ended December 2006, 2005 and 2004, we spent $160.4 million, $128.9 million and $56.7 million, respectively, to develop our proved undeveloped reserves.

	As of December 31,		
	2006	**2005**	**2004**
		(in thousands)	
Property acquisition and leasehold costs			
Unevaluated	$ 2,334	$ 31,009	$ 28,059
Proved	112,646	232,784	179,281
Exploration costs	71,195	112,634	63,646
Development costs			
Development drilling	426,615	366,902	245,971
Asset retirement obligations costs assumed [1]	38,113	23,651	12,116
Asset retirement obligations costs properties sold [1]	(88,375)	(32)	(12,714)
Asset retirement expenditures [1]		(971)	(2,362)
Total development costs	376,353	389,550	243,011
Total costs incurred	$ 562,528	$ 765,977	$ 513,997

(1) Asset retirement obligation costs reflect abandonment obligations assumed during the year and revisions to prior estimates. As a result of the dispositions of substantially all of our Gulf of Mexico assets during 2006 and our South Louisiana and

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Appalachian Basin assets during 2004, asset retirement obligations were reduced by $88.7 million during 2006 and by $12.7 million in 2004. Actual retirement expenditures reflect plugging and abandonment costs during the year.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Natural Gas and Oil Reserves

The following summarizes the policies we used in the preparation of the accompanying natural gas and oil reserve disclosures, standardized measures of discounted future net cash flows from proved natural gas and oil reserves and the reconciliations of standardized measures from year to year. The information disclosed, as prescribed by the Statement of Financial Accounting Standards No. 69, is an attempt to present the information in a manner comparable with industry peers.

The information is based on estimates of proved reserves attributable to our interest in natural gas and oil properties as of December 31 of the years presented. These estimates were prepared by independent petroleum consultants. Proved reserves are estimated quantities of natural gas and crude oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

1. Estimates are made of quantities of proved reserves and future periods during which they are expected to be produced based on year-end economic conditions.

2. The estimated future cash flows are compiled by applying year-end prices of natural gas and oil relating to our proved reserves to the year-end quantities of those reserves.

3. The future cash flows are reduced by estimated production costs, costs to develop and produce the proved reserves and abandonment costs, all based on year-end economic conditions.

4. Future income tax expenses are based on year-end statutory tax rates giving effect to the remaining tax basis in the natural gas and oil properties, other deductions, credits and allowances relating to our proved natural gas and oil reserves.

5. Future net cash flows are discounted to present value by applying a discount rate of 10%.

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of our natural gas and oil reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

The standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves is as follows and does not include cash flows associated with hedges outstanding at each of the respective reporting dates.

	As of December 31,		
	2006	**2005**	**2004**
		(in thousands)	
Future cash inflows	$ 3,547,732	$ 7,065,492	$ 4,558,560
Future production costs	(957,940)	(1,403,934)	(812,800)
Future development costs	(594,544)	(874,327)	(545,192)
Future income taxes	(555,522)	(1,520,815)	(976,611)
Future net cash flows	1,439,726	3,266,416	2,223,957
10% annual discount for estimated timing of cash flows	(702,500)	(1,299,392)	(783,902)
Standardized measure of discounted future net cash flows	$ 737,226	$ 1,967,024	$ 1,440,055

Year-end prices per Mcf of natural gas used in making standardized measure determinations as of December 31, 2006, 2005 and 2004 were $4.94, $8.15 and $5.68, respectively. Year-end prices per Bbl of oil used in making these same calculations were $49.94, $53.27 and $41.67, respectively, for 2006, 2005 and 2004.

At December 31, 2006, our standardized measure of discounted future net cash flows includes estimated future development costs for our proved undeveloped reserves for the next three years of $135.1 million, $207.2 million and $104.3 million, respectively, for 2007, 2008 and 2009.

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The following table summarizes changes in the standardized measure of discounted future net cash flows.

	As of December 31,		
	2006	**2005**	**2004**
		(in thousands)	
Beginning of the year	$ 1,967,024	$ 1,440,055	$ 1,504,406
Revisions in quantities	(66,056)	(251,007)	(59,549)
Changes in prices	(859,166)	943,487	(34,170)
Changes in future development costs	(44,270)	(198,013)	(35,056)
Development costs incurred during the period	195,723	209,322	85,439
Extensions and discoveries, net of related costs	237,296	620,243	445,908
Sales of natural gas and oil, net of production costs	(499,057)	(787,013)	(639,555)
Accretion of discount	287,742	207,197	205,641
Net change in income taxes	644,930	(278,475)	(79,913)
Purchase of reserves in place	55,115	250,520	247,671
Sale of reserves in place	(1,137,244)	(4,904)	(110,877)
Production timing and other	(44,811)	(184,388)	(89,890)
End of year	$ 737,226	$ 1,967,024	$ 1,440,055

Estimated Net Quantities of Natural Gas and Oil Reserves

The following table sets forth our proved reserves, including changes, and proved developed reserves (all within the United States) at the end of each of the three years in the period ended December 31, 2006, 2005 and 2004.

	Natural Gas (MMcf)			Crude Oil, Liquids and Condensate (MBbls)		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**
Beginning of the year reserves	793,074	749,114	709,883	11,291	7,335	7,481
Revisions of previous estimates	(33,797)	(66,205)	(13,232)	471	1,097	(1,110)
Extensions and discoveries	153,020	135,336	162,719	1,140	1,395	255
Production	(82,528)	(105,809)	(115,855)	(938)	(1,417)	(1,355)
Purchase of reserves in place	30,779	81,704	67,806	237	3,000	2,245
Sales of reserves in place	(188,912)	(1,066)	(62,207)	(7,586)	(119)	(181)
End of year reserves	671,636	793,074	749,114	4,615	11,291	7,335
Proved developed reserves:						
Beginning of year	506,212	475,080	487,867	6,933	3,535	4,073

End of year	446,109	506,212	475,080	3,589	6,933	3,535

	Natural Gas Equivalents (MMcfe)		
	2006	2005	2004
Beginning of year reserves	860,820	793,124	754,769
Revisions of previous estimates	(30,971)	(59,623)	(19,892)
Extensions and discoveries	159,860	143,706	164,249
Production	(88,156)	(114,311)	(123,985)
Purchase of reserves in place	32,201	99,704	81,276
Sales of reserves in place	(234,428)	(1,780)	(63,293)
End of year reserves	699,328	860,820	793,124
Proved developed reserves:			
Beginning of year	547,810	496,290	512,305
End of year	467,643	547,810	496,290

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NOTE 13 Quarterly Financial Information (Unaudited)

The following represents our unaudited quarterly results for years ended December 31, 2006 and 2005. The quarterly results were prepared in accordance with GAAP and reflect all adjustments that are, in the opinion of management, necessary for a fair statement of the results. These adjustments are of a normal recurring nature.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2006 (1)				
Total revenues(2)	$ 177,604	$ 145,914	$ 131,337	$ 76,742
Total operating expenses(3)	124,436	93,353	81,809	105,151
Income (loss) from operations	53,168	52,561	49,528	(28,409)
Net income (loss)(4)	29,772	23,371	34,003	(19,363)
Net income (loss)per share basic(7)	$ 1.03	$ 0.82	$ 1.22	$ (0.69)
Net income (loss) per share diluted(7)	$ 1.02	$ 0.81	$ 1.22	$ (0.69)
2005				
Total revenues(5)	$ 165,720	$ 175,817	$ 125,413	$ 154,593
Total operating expenses(6)	104,119	106,117	109,180	117,391
Income from operations	61,601	69,700	16,233	37,202
Net income	33,438	43,830	8,081	19,820
Net income per share basic(7)	$ 1.17	$ 1.53	$ 0.28	$ 0.69
Net income per share diluted(7)	$ 1.16	$ 1.51	$ 0.28	$ 0.69

(1) Operating results for 2006 reflect the sale of substantially all of our Gulf of Mexico assets with completion of the sale of the Texas offshore assets on March 31, 2006 and the completion of the sale of the Louisiana offshore assets on June 1, 2006. In addition, the fluctuations in total revenues each quarter

reflect the loss of hedge accounting during the first quarter of 2006 and the subsequent application of mark-to-market accounting for open derivative contracts. The loss of hedge accounting was a result of market factors subsequent to Hurricanes Katrina and Rita and the sale of the Gulf of Mexico assets.

(2) For the fourth quarter of 2006, total revenues includes a net loss of $41.2 million from hedging activities which includes the following items: (i) a $1.5 million loss realized on contracts settled during the fourth quarter; (ii) an unrealized loss of $46.6 million for the mark-to-market change in the fair value of open derivative contracts; and (iii) a $6.9 million unrealized gain

for ineffective contracts.

(3) For the fourth quarter of 2006, total operating expenses includes a writedown in the carrying value of our natural gas and oil properties of $19.0 million ($12.3 million net of tax) incurred due to the cumulative effect of higher finding and development costs during recent years, combined with higher estimated future operating and development costs at year-end 2006.

(4) For the fourth quarter of 2006, the loss from operations and the net loss were primarily due to realized natural gas prices that averaged $5.80 per Mcf; higher depreciation, depletion and amortization expense caused by higher rates due to higher finding and development costs and higher estimated future

development costs; and a writedown in the carrying value of our natural gas and oil properties of $19.0 million ($12.3 million net of tax).

(5) For the fourth quarter of 2005, total revenues includes a net loss of $116.5 million from hedging activities which includes the following items: (i) a $164.5 million loss realized on contracts settled during fourth quarter; (ii) a $20.6 million unrealized gain for the deferral of losses on settled contracts that were deferred to accumulated other comprehensive income due to an offshore production shortfall; and (iii) a $27.6 million unrealized gain for ineffective contracts which includes $26.4 million due to loss of correlation between the

NYMEX price and the Houston Ship Channel index during the fourth quarter of 2005.

(6) For the fourth quarter of 2005, total operating expenses includes $4.0 million in additional general and administrative expenses related to severance and other separation related payments made to certain former employees, including our former Chief Financial Officer.

(7) Quarterly earnings per share is based on the weighted average number of shares outstanding during the quarter. Because of changes in the number of shares outstanding during the quarters due to the exercise of stock options and/or the issuance or repurchase of common stock, the sum of

quarterly earnings per share may not equal earnings per share for the year

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INDEX TO EXHIBITS

2.1	Agreement and Plan of Merger dated as of January 7, 2007 by and among the Company, Forest Oil Corporation and MJCO Corporation (filed as exhibit 2.1 to our Current Report on Form 8-K dated January 7, 2007 (file No. 001-11899) and incorporated by reference herein).
3.1	Restated Certificate of Incorporation, as amended, including the Certificate of Amendment thereto dated April 26, 2005 (filed as exhibit 3.1 to our Quarterly Report on Form 10-Q for the period ended March 31, 2005 (file No. 001-11899) and incorporated by reference herein).
3.2	Restated Bylaws of The Houston Exploration Company (filed as Exhibit 3.2 to our Annual Report on Form 10-K for the year ended December 31, 2005 (File No.001-11899) and incorporated by reference).
4.1	Indenture, dated as of June 10, 2003, between The Houston Exploration Company and the Bank of New York, as Trustee, with respect to the 7% Senior Subordinated Notes due 2013 (filed as Exhibit 4.2 to our Registration Statement on Form S-4 (Registration No. 333-106836) and incorporated by reference).
4.2	Rights Agreement, dated as of August 12, 2004, between The Houston Exploration Company and The Bank of New York, as Rights Agent (filed as Exhibit 4.1 to our Current Report on Form 8-K dated August 13, 2004 (File No. 001-11899) and incorporated by reference).
4.3	First Amendment dated as of May 2, 2005, to the Rights Agreement dated as of August 12, 2004 between The Houston Exploration Company and The Bank of New York, as Rights Agent (filed as exhibit 4.1 to our Quarterly Report on Form 10-Q for the period ended March 31, 2005 (file No. 001-11899) and incorporated by reference herein).
4.4	Second Amendment to Rights Agreement dated as of January 7, 2007 between The Houston Exploration Company and The Bank of New York, as Rights Agent (filed as exhibit 4.1 to our Current Report on Form 8-K dated January 7, 2007 (file No. 001-11899) and incorporated by reference herein).
4.5	Form of Certificate of Designation of Series A Junior Participating Preferred Stock of The Houston Exploration Company (filed as Exhibit 4.2 to our Current Report on Form 8-K dated August 13, 2004 (File No. 001-11899) and incorporated by reference).
10.1	Amended and Restated Credit Agreement dated November 30, 2005 among The Houston Exploration Company and Wachovia Bank, National Association, as Issuing Bank and Administrative Agent; The Bank of Nova Scotia and Bank of America as Co-Syndication Agents; and BNP Paribas and Comerica Bank as Co-Documentation Agents (filed as exhibit 99.1 to our Current Report on Form 8-K dated November 30, 2005 (File No. 001-11899) and incorporated by reference).
10.2	First Amendment to Amended and Restated Credit Agreement effective May 31, 2006 among The Houston Exploration Company and Wachovia Bank, National Association, as Issuing Bank and Administrative Agent; The Bank of Nova Scotia and Bank of America as Co-Syndication Agents; and BNP Paribas and Comerica Bank as Co-Documentation Agents (filed as Exhibit 10.1 to our Quarterly Report on Form 10-Q for the period ended June 30, 2006 (File No. 001-11899) and incorporated by reference).

10.3	Purchase and Sale Agreement, dated September 3, 2003, by and among Transworld Exploration and Production, Inc., as Seller, and The Houston Exploration Company, as Buyer (filed as Exhibit 2.1 to our Current Report on Form 8-K dated October 15, 2003 (file No. 001-11899) and incorporated by reference).
10.4	Asset Contribution Agreement dated June 2, 2004 between The Houston Exploration Company and Seneca-Upshur Petroleum, Inc. (filed as Exhibit 99.3 to our Current Report on Form 8-K dated June 30, 2004 (File No. 001-11899) and incorporated by reference).
10.5	Tax Matters Agreement dated as of June 2, 2004 by and among The Houston Exploration Company, Seneca-Upshur Petroleum, Inc., THEC Holdings Corp., and KeySpan Corporation (filed as Exhibit 99.4 to our Current Report on Form 8-K dated June 30, 2004 (File No. 001-11899) and incorporated by reference).
10.6	Distribution Agreement dated as of June 2, 2004 by and among The Houston Exploration Company, Seneca-Upshur Petroleum, Inc., THEC Holdings Corp. and KeySpan Corporation (filed as Exhibit 99.2 to our Current Report on Form 8-K dated June 30, 2004 (File No. 001-11899) and incorporated by reference).
10.7	Purchase and Sale Agreement, dated September 17, 2004, between The Houston Exploration Company and Orca Energy, L.P. (filed as Exhibit 2.1 to our Current Report on Form 8-K dated November 1, 2004 (File No. 001-11899) and incorporated by reference).
10.8	Purchase and Sale Agreement dated October 21, 2005 by and between Kerr-McGee Oil & Gas Onshore LP D/B/A KMOG Onshore LP and Westport Oil and Gas Company, L.P., as sellers, and The Houston Exploration Company, as buyer, (filed as exhibit 99.2 to our Current Report on Form 8-K dated November 30, 2005 (File No. 001-11899) and incorporated by reference).
10.9	Purchase and Sale Agreement dated February 28, 2006 between The Houston Exploration Company, as seller, and Merit Management Partners I, L.P., Merit Management Partners II, L.P., Merit Management Partners III, L.P., Merit Energy Partners III, L.P., Merit Energy Partners D-III, L.P., Merit Energy Partners E-III, L.P. and Merit Energy Partners F-III, L.P., collectively, as buyer (filed as Exhibit 10.1 to our Quarterly Report on Form 10-Q for the period ended March 31, 2006 (File No. 001-11899) and incorporated by reference).
10.10	Purchase and Sale Agreement dated April 7, 2006 between The Houston Exploration Company, as seller, and Merit Management Partners I, L.P., Merit Management Partners II, L.P., Merit Management Partners III, L.P., Merit Energy Partners III, L.P., Merit Energy Partners D-III, L.P., Merit Energy Partners E-III, L.P. and Merit Energy Partners F-III, L.P., collectively, as buyer (filed as Exhibit 99.1 to our Current Report on Form 8-K dated June 2, 2006 (File No. 001-11899) and incorporated by reference).
10.11(2)	Deferred Compensation Plan for Non-Employee Directors (filed as Exhibit 10.24 to our Annual Report on Form 10-K for the year ended December 31, 1997 (File No. 001-11899) and incorporated by reference).
10.12(2)	Amendment dated April 26, 2005, but effective as of December 31, 2004, to The Houston Exploration Company Non-Employee Director Deferred Compensation Plan (filed as Exhibit 10.4

to our Current Report on Form 8-K dated July 31, 2006 (File No. 001-11899) and incorporated by reference).

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10.13(2)	The Houston Exploration Company Post-2004, AJCA Compliant Deferred Compensation Plan for Non-Employee Directors dated April 26, 2005, effective as of January 1, 2005 (filed as Exhibit 10.5 to our Current Report on Form 8-K dated July 31, 2006 (File No. 001-11899) and incorporated by reference).
10.14(2)	Compensation Table for Non-Employee Directors, effective January 1, 2006 (filed as exhibit 99.2 to our Current Report on Form 8-K dated January 6, 2006.
10.15(2)	Amended and Restated 1996 Stock Option Plan (filed as Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 1998 (File No. 001-11899) and incorporated by reference).
10.16(2)	1999 Non-Qualified Stock Option Plan dated October 26, 1999 (filed as Exhibit 10.24 to our Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 001-11899) and incorporated by reference).
10.17(2)	Amended and Restated 2002 Long-Term Incentive Plan effective May 17, 2002, adopted October 26, 2003 (filed as Exhibit 10.31 to our Annual Report on Form 10-K for the year ended December 31, 2003 (file No. 001-11899) and incorporated by reference).
10.18(2)	Amended and Restated 2004 Long Term Incentive Plan (filed as exhibit 99.1 to our Current Report on Form 8-K dated January 31, 2006 (File No. 001-11899) and incorporated by reference).
10.19(2)	Supplemental Executive Pension Plan dated May 1, 1996 (filed as exhibit 10.23 to our Registration Statement on Form S-1/A (Amendment No. 2) (Registration No. 333-4437) and incorporated by reference).
10.20(2)	The Houston Exploration Company Supplemental Executive Retirement Plan (Amended and Restated on July 25, 2006) (filed as Exhibit 10.1 to our Current Report on Form 8-K dated July 31, 2006 (File No. 001-11899) and incorporated by reference).
10.21(2)	First Amendment to The Houston Exploration Company Supplemental Executive Retirement Plan (filed as exhibit 10.3 to our Current Report on Form 8-K dated January 7, 2007 (file No. 001-11899) and incorporated by reference herein).
10.22(2)	Executive Deferred Compensation Plan dated January 1, 2002 (filed as Exhibit 10.28 to our Annual Report on Form 10-K for the year ended December 31, 2002 (File No. 001-11899) and incorporated by reference).
10.23(2)	Amendment [No. 1] to The Houston Exploration Company Executive Deferred Compensation Plan (filed as exhibit 99.2 to our Current Report on Form 8-K dated January 31, 2006 (File No. 001-11899) and incorporated by reference).
10.24(2)	Amendment No. 2 dated July 25, 2006, but effective as of December 31, 2004, to The Houston Exploration Company Executive Deferred Compensation Plan (filed as Exhibit 10.2 to our Current Report on Form 8-K dated July 31, 2006 (File No. 001-11899) and incorporated by reference).
10.25(2)	

	The Houston Exploration Company 2005 Executive Deferred Compensation Plan (filed as Exhibit 10.3 to our Current Report on Form 8-K dated July 31, 2006 (File No. 001-11899) and incorporated by reference).
10.26[2]	Amended and Restated Employment Agreement dated February 8, 2005 between The Houston Exploration Company and William G. Hargett (filed as Exhibit 10.1 to our

	Current Report on Form 8-K dated February 8, 2005 (File No. 001-11899) and incorporated by reference).
10.27(2)	Amendment No. 1, dated October 24, 2006, to the Amended and Restated Employment Agreement dated February 8, 2005 between The Houston Exploration Company and William G. Hargett (filed as Exhibit 10.1 to our Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.38(2)	Amended and Restated Employment Agreement between The Houston Exploration Company and Steven L. Mueller dated February 8, 2005 (filed as Exhibit 10.19 to our Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 001-11899) and incorporated by reference).
10.29(2)	Amendment No. 1, dated October 24, 2006, to the Amended and Restated Employment Agreement dated February 8, 2005 between The Houston Exploration Company and Steven L. Mueller (filed as Exhibit 10.2 to our Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.30(2)	Amended and Restated Employment Agreement between The Houston Exploration Company and John H. Karnes dated February 8, 2005 (filed as Exhibit 10.20 to our Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 001-11899) and incorporated by reference).
10.31(2)	Separation Agreement and General Release dated December 8, 2005 between The Houston Exploration Company and John H. Karnes (filed as exhibit 99.1 to our Current Report on Form 8-K dated December 12, 2005 (File No. 001-11899) and incorporated by reference).
10.32(2)	Amended and Restated Employment Agreement between The Houston Exploration Company and James F. Westmoreland dated February 8, 2005 (filed as Exhibit 10.21 to our Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 001-11899) and incorporated by reference).
10.33(2)	Amendment No. 1, dated October 24, 2006, to the Amended and Restated Employment Agreement dated February 8, 2005 between The Houston Exploration Company and James F. Westmoreland (filed as Exhibit 10.7 to our Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.34(2)	Amended and Restated Employment Agreement between The Houston Exploration Company and Roger B. Rice dated February 8, 2005 (filed as Exhibit 10.22 to our Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 001-11899) and incorporated by reference).
10.35(2)	Amendment No. 1, dated October 24, 2006, to the Amended and Restated Employment Agreement dated February 8, 2005 between The Houston Exploration Company and Roger B. Rice (filed as Exhibit 10.5 to our Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.36(2)	Employment Agreement dated February 10, 2005 between The Houston Exploration Company and Joanne C. Hresko (filed as Exhibit 10.3 to our Current Report on Form 8-K dated February 8, 2005 (File No. 001-11899) and incorporated by reference).

10.37[2]	Amendment No. 1, dated October 24, 2006, to the Employment Agreement dated February 10, 2005, between The Houston Exploration Company and Joanne C. Hresko (filed as Exhibit 10.8 to our Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).

10.38(2)	Employment Agreement effective March 10, 2005, between The Houston Exploration Company and John E. Bergeron, Jr. (filed as exhibit 99.2 to our Current Report on Form 8-K dated March 10, 2005 (File No. 001-11899) and incorporated by reference).
10.39(2)	Amendment No. 1, dated October 24, 2006, to the Employment Agreement dated March 10, 2005, between The Houston Exploration Company and John E. Bergeron, Jr. (filed as Exhibit 10.9 to our Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.40(2)	Employment Agreement effective April 13, 2005, between The Houston Exploration Company and Jeffrey B. Sherrick (filed as exhibit 99.2 to our Current Report on Form 8-K dated April 13, 2005 (File No. 001-11899) and incorporated by reference).
10.41(2)	Amendment No. 1, dated October 24, 2006, to the Employment Agreement dated April 13, 2005, between The Houston Exploration Company and Jeffrey B. Sherrick (filed as Exhibit 10.6 to our Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.42(2)	Employment Agreement dated January 18, 2006 between The Houston Exploration Company and Robert T. Ray (filed as exhibit 99.1 to our Current Report on Form 8-K dated January 18, 2006 (File No. 001-11899) and incorporated by reference).
10.43(2)	Amendment No. 1, dated October 24, 2006, to the Employment Agreement dated January 18, 2006, between The Houston Exploration Company and Robert T. Ray (filed as Exhibit 10.3 to our Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.44(2)	Employment Agreement dated March 27, 2006 between The Houston Exploration Company and Carolyn M. Campbell (filed as Exhibit 99.1 to our Current Report on Form 8-K dated March 27, 2006 (File No. 001-11899) and incorporated by reference).
10.45(2)	Amendment No. 1, dated October 24, 2006, to the Employment Agreement dated March 27, 2006, between The Houston Exploration Company and Carolyn M. Campbell (filed as Exhibit 10.4 to our Current Report on Form 8-K dated October 27, 2006 (File No. 001-11899) and incorporated by reference).
10.46	Form of Amendment No. 2 to [Amended and Restated] Employment Agreement entered into by and between The Houston Exploration Company and each of William G. Hargett, Steven L. Mueller, James F. Westmoreland, Roger B. Rice, Joanne C. Hresko, John E. Bergeron Jr., Jeffrey B. Sherrick, Robert T. Ray and Carolyn M. Campbell (filed as Exhibit 10.1 to our Current Report on Form 8-K dated January 7, 2007 (file No. 001-11899) and incorporated by reference herein).
10.47(2)	Change of Control Plan dated October 26, 1999 (filed as Exhibit 10.25 to our Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 001-11899) and incorporated by reference).
10.48(1)(2)	First Amendment to The Houston Exploration Company Change of Control Plan dated May 17, 2002.

10.49[2]	Second Amendment to The Houston Exploration Company Change of Control Plan (filed as exhibit 10.4 to our Current Report on Form 8-K dated January 7, 2007 (file No. 001-11899) and incorporated by reference herein).

10.50[2]	Form of Indemnification Agreement for Directors and Executive Officers (filed as Exhibit 10.8 to our Quarterly Report on Form 10-Q for the period ended June 30, 2006 (File No. 001-11899) and incorporated by reference).
10.51[2]	Form of Non-Qualified Stock Option Agreement (filed as Exhibit 10.9 to our Quarterly Report on Form 10-Q for the period ended June 30, 2006 (File No. 001-11899) and incorporated by reference).
10.52[2]	Form of Director Restricted Stock Award Agreement (filed as Exhibit 10.10 to our Quarterly Report on Form 10-Q for the period ended June 30, 2006 (File No. 001-11899) and incorporated by reference).
10.53[2]	Form of Employee Restricted Stock Award Agreement (filed as Exhibit 10.11 to our Quarterly Report on Form 10-Q for the period ended June 30, 2006 (File No. 001-11899) and incorporated by reference).
12.1[1]	Computation of ratio of earnings to fixed charges.
21.1[1]	Subsidiaries of The Houston Exploration Company.
23.1[1]	Consent of Deloitte & Touche LLP.
23.2[1]	Consent of Netherland, Sewell & Associates.
23.3[1]	Consent of Miller and Lents.
31.1[1]	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2[1]	Certification of Robert T. Ray, Chief Financial Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1[1]	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2[1]	Certification of Robert T. Ray, Chief Financial Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(1) Filed herewith.

(2) Management contract or compensation plan.