HOUSTON EXPLORATION CO
Form 10-K
March 03, 2006

Table of Contents

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

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

For the fiscal year ended December 31, 2005

OR

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

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 **(State or Other Jurisdiction of Incorporation or Organization)**	**22-2674487** **(IRS Employer Identification No.)**
1100 Louisiana, Suite 2000 **Houston, Texas** **(Address of Principal Executive Offices)**	**77002-5215** **(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, $.01 par value	New York Stock Exchange
7% Senior Subordinated Notes due 2013	

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 o No þ

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 the voting stock held by non-affiliates of the registrant was approximately $1.026 billion, based on the closing sales price of $53.05 per share of the registrant s common stock as reported by on the New York Stock Exchange as of June 30, 2005, the last business day of the registrant s most recently completed second fiscal quarter. As of March 1, 2006, 29,067,430 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 April 28, 2006 are incorporated by reference into Part III of this Form 10-K.

Table of Contents

TABLE OF CONTENTS

Table of Contents

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 (the Exchange Act). These forward-looking statements generally are identified by the words believe, project, expect, anticipate, estimate, intend, strategy, plan, target, will, would, will be, will continue, will likely result, and similar expressions. Forward-looking statements are ba 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 15 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 website at http://www.houstonexploration.com as soon as reasonably practicable after we electronically file such material with, or otherwise furnish it to, the SEC.

We have adopted a Code of Business Conduct to provide guidance to our directors, officers and employees on matters of business conduct and ethics, including compliance standards and procedures. We have also 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 Code of Business Conduct 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 about any amendment to or waiver of, these codes with respect to our executive officers and directors.

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, a copy of our Code of Business Conduct, Code of Ethics for Senior Financial Officers, Corporate Governance Guidelines and the charters of the Committees referenced above are available in print 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 included on pages G-1 through G-2.

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.

Table of Contents

Part I.
Items 1. and 2. Business and Properties
Overview of Our Business

We are an independent natural gas and oil producer concentrating on growing reserves and production through 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 began exploring for natural gas and oil on behalf of KeySpan Corporation, our then parent company. KeySpan is a diversified energy provider whose principal natural gas distribution and electric generation operations are located in the Northeastern United States. In September 1996, we completed our initial public offering and sold approximately 31% of our shares to the public. Through three separate transactions, the first in February 2003 and last in November 2004, KeySpan completely divested its investment in the common stock of our company.

At December 31, 2005, we had operations in five producing regions within the United States: South Texas; the Arkoma Basin of Arkansas and Oklahoma; East Texas; the Uinta and DJ Basins in the Rocky Mountains; and the Gulf of Mexico.

Our total net proved reserves as of December 31, 2005 were 861 billion cubic feet equivalent or Bcfe, with onshore reserves totaling 616 Bcfe. Our reserves are fully engineered on an annual basis by independent petroleum engineers. Approximately 64% of our proved reserves at December 31, 2005, were classified as proved developed. Our daily production during 2005 averaged 313 million cubic feet of natural gas equivalent or MMcfe and was significantly curtailed during the last four months of 2005 and into the first quarter of 2006 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 our intent to explore the sale of our Gulf of Mexico assets and to shift our operating focus onshore. This strategic change will leverage our strength of developing complex, tight or low permeable natural gas reservoirs while providing flexibility to expand both in our present core areas and other tight gas basins. During 2005, our offshore assets accounted for 40% of our 2005 production and represented 245 Bcfe, or 28% of our proved reserves, at December 31, 2005.

On February 28, 2006, we entered into an agreement to sell the Texas portion of our Gulf of Mexico assets to certain partnerships affiliated with Merit Energy Company for $220 million in cash, subject to adjustment and customary closing conditions. The transaction is scheduled to close on or about March 31, 2006, with an effective date of January 1, 2006. The sale process with respect to our remaining Gulf of Mexico assets is ongoing. If a sale is not consummated, we expect to continue to operate and may consider other strategic alternatives with respect to these assets.

The Texas portion of our Gulf of Mexico assets accounted for approximately 18% of our 2005 production and represented 58.5 Bcfe, or 7% of our total proved reserves, at December 31, 2005. We expect to use the proceeds from the sale of the Texas portion of our Gulf of Mexico assets primarily to acquire longer-lived natural gas assets onshore in North America and to repay existing debt. Where possible, we plan to structure our asset reinvestment to minimize taxes on any gain realized from the sale.

Table of Contents

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, we employ the following strategies:

§ *Balanced Growth.* We pursue a balanced strategy of exploiting our existing reserves, exploring for new reserves and acquiring new properties. Typically, at least 70% 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.

§ *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, 2005, approximately 92% of our proved reserves were natural gas and, for the year ended December 31, 2005, approximately 93% 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 allowing a higher cash margin. While we believe that the pricing fundamentals for natural gas will remain strong for the foreseeable future, we have explored and may continue to explore opportunities to balance our asset portfolio with additional oil properties. Such activities depend on the relative pricing outlook for both natural gas and oil, acquisition opportunities, and operational considerations, including our objectives of shifting operations onshore, lowering finding and development costs, and lengthening reserve life.

§ *Concentrate on Core Areas.* We focus our drilling activities on properties in 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, 2005, approximately 89% of our reserves were located in three core areas: South Texas, the Gulf of Mexico and the Arkoma Basin. Upon completion of the pending sale of the Texas portion of our Gulf of Mexico assets, South Texas and the Arkoma Basin will comprise approximately 47% and 19%, respectively, of our reserves. In addition, through our current activities in both the Rocky Mountains and East Texas, either one or both of these regions could develop into a core area in the future. Further, we plan to seek opportunities in one or more new areas where we believe we can utilize the strengths of our existing workforce to sustain future growth.

§ *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, 2005, we operated approximately 80% of our wells and our average working interest was approximately 73%.

§ *Focus on Low 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. Although we expect our costs will increase in 2006, we believe that our operating structure provides us a significant competitive advantage because it maximizes our margins and cash flows. For 2005, our lease operating expense was $0.59 per Mcfe.

§ *Employ Conservative Financial Policies.* We typically fund 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, and may increase from time to time in the future as we continue to make acquisitions, we will seek to maintain conservative debt levels. Among other things, this will provide us with flexibility to continually review and adjust our capital expenditure program during the year based on operational developments, commodity prices, service costs, acquisition opportunities and numerous other factors. In addition to bank borrowings and public debt, we may also issue common stock in connection with future acquisitions, either initially as an element of the transaction consideration or subsequently as part of a financing plan.

§ *Managing Commodity Price Risks.* We have historically employed a hedging program intended to reduce our exposure to adverse commodity price fluctuations and provide more predictable cash flows that allow us to 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 by taking advantage of prices when they reach levels we believe lock in targeted rates of return on our invested capital.

Table of Contents

Properties and Operating Areas

The table below summarizes certain data for our core operating areas for the year ended December 31, 2005:

	Activity and Balances as of or for the Year Ended December 31, 2005					
	Average Daily Production	Total Production	Total Proved Reserves	Percentage Total Proved Reserves	Wells Drilled	
Area					Total	Successful
	(MMcfe/d)	(MMcfe)	(MMcfe)		(Gross)	(Gross)
South Texas	134	48,983	374,163	44%	95	82
Arkoma Basin	43	15,789	151,054	18%	61	60
East Texas	5	1,812	61,308	7%	16	16
Rocky Mountains	5	1,665	26,713	3%	149	128
Other	1	372	2,986			
Total onshore	188	68,621	616,224	72%	321	286
Gulf of Mexico	125	45,690	244,596	28%	15	12
Total	313	114,311	860,820	100%	336	298

South Texas. Our South Texas properties are concentrated in the Charco, North Roleta, Haynes and South Trevino Fields of Zapata County; the Alexander, Hubbard and South Laredo Fields of Webb County; and the Northeast Thompsonville Field in Jim Hogg County. In November 2005, we spent $159.0 million to expand our South Texas operating base by acquiring 62 Bcfe of proved reserves and interests in 300 producing wells and 26,000 net acres covering 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. These properties are expected to add significant drilling opportunities for 2006. We plan to add a seventh drilling rig early in the second quarter of 2006 at which time we expect to spud our first well in the Rincon Field.

As of December 31, 2005, our South Texas properties covered approximately 94,600 net acres and we owned interests in 872 producing wells, 764 or 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. In total, our net South Texas production has more than tripled since we began operations in the area in July 1996, to an average of 134 MMcfe per day during 2005. Over the course of nine and a half years, we drilled 451 wells, of which 366 were successful, produced 342 Bcfe and added 603 Bcfe in reserves through drilling and acquisitions. South Texas accounted for 43% of our total production during 2005 and approximately 44% of our reserve base as of December 31, 2005

Gulf of Mexico. Our offshore properties are located in the shallow waters of the Outer Continental Shelf. Our key producing properties are located in the western and central Gulf of Mexico and include the Mustang Island, Matagorda Island, Galveston Island, High Island, East Cameron, West Cameron, Eugene Island and Main Pass areas. Over the last three years, our offshore operations have become less exploration-focused, as we have undertaken a number of exploration and exploitation activities aimed at maximizing production from older, previously produced fields acquired from third parties.

In November 2005, we announced our intent to explore the sale of our Gulf of Mexico assets and to shift our operating focus onshore. On February 28, 2006, we announced the pending sale, subject to customary closing conditions, of the Texas portion of these assets. The sale process with respect to our remaining Gulf of Mexico assets

is ongoing and if a sale is not consummated, we expect to continue to operate and may consider other strategic alternatives with respect to these assets.
As of December 31, 2005, we held interests in 136 blocks in federal and state waters, of which 78 were developed. As of December 31, 2005, we operated 45 of our developed blocks, which accounted for approximately 80% of our offshore production during 2005. We had a total of 97 producing platforms and production caissons, of which we operated 61. At December 31, 2005, we held interests in 70 blocks in offshore Texas state and federal waters, of which 33 were developed. Our Texas assets included 38 producing platforms and production caissons. During 2005, production from our Gulf of Mexico properties comprised approximately 40% of our total production, averaging 125 MMcfe per day and was significantly curtailed during the last four months of 2005 as a result of Hurricanes Katrina and Rita that hit the Louisiana and Texas Gulf coasts in August and September 2005.

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, 2005, we had approximately 37,200 net acres under lease and we owned working interests in 411 producing natural gas wells, 289 of which we operated. Wells average a depth of 5,500 feet and production is from the Atoka formation. Beginning in 2003, we significantly increased our developmental drilling program with the expansion of in-field drilling opportunities as a result of a series of downspacing initiatives authorized by the Arkansas Oil and Gas Commission, first in September 2002 from 640 acres per well to 160 acres per well, again in September 2003 from 160 acres to 80 acres per well, and finally in December 2004 to approximately 40 acres per well. During 2005, average daily production increased by 13% from 38 MMcfe per day during 2004 to 43 MMcfe per day during 2005. Acquisition opportunities have been scarce or limited in the Arkoma Basin during 2005 and 2004 and, as a result, our current activities are focused on the substantial number of in-field drilling opportunities within our existing acreage. During 2006, we plan to continue our in-field drilling program with three rigs drilling during the year. In addition, during the fourth quarter of 2005, we participated with a 40% working interest in a 13,000 foot exploration well that is preparing to test Atoka sands.

East Texas. During 2005, we expanded our existing operations and reserve base located in the Willow Springs Field in Gregg County, Texas through a series of three acquisitions totaling a $38.7 million where we added approximately 37.5 Bcfe in proved reserves. We purchased interests in producing properties and undeveloped acreage in the South Oak Hill Field located in Rusk County and the North Blocker Field in Harrison County. We began drilling within two months of the initial acquisition of these properties in March 2005, and successfully drilled and completed 16 of 16 new wells, adding approximately 13 Bcfe in proved reserves, and increased our average daily production from 2 MMcfe per day in January 2005 to 8 MMcfe per day in December 2005. At December 31, 2005, we had two rigs drilling and owned interests in 49 natural gas wells and three oil wells. We operated 48 of the natural gas wells and all three of the oil wells. Our average working interest in all 52 wells was 80%.

Rocky Mountains. Our Rocky Mountain properties are located in the Uinta Basin of Northeastern Utah and the DJ Basin in Eastern Colorado. At December 31, 2005, we had accumulated more than 566,000 net acres with estimated net proved reserves of 27 Bcfe. During 2005, production from our Rocky Mountain properties averaged approximately 5 MMcfe per day, net to our interests.

During 2005, we continued proving up and delineating portions of our Uinta Basin acreage where we actively began drilling during 2004. As part of this effort, we partnered with two different groups in an effort to both optimize our capital utilization and accelerate our exploration efforts in that area. We drilled or participated in the drilling of a total of 36 wells, of which 30, or 83%, were successful. As in the previous year, during 2005, we experienced delays in bringing new production on-line, primarily due to difficulties in obtaining pipeline right-of-ways. At December 31, 2005, 12 of our newly completed Uinta wells were shut-in and awaiting approvals for pipeline right-of-ways.

In the DJ Basin, we expanded our exploration efforts along the Niobrara Trend and drilled 107 wells, successfully completing 98, or 92%. We added approximately 18 Bcfe from drilling, with first production in mid-July 2005. A second gathering system was completed in January 2006. Subsequent to December 31, 2005, 30 of the 50 wells shut-in at year-end waiting connection to the gathering system commenced production, adding approximately 2.4 MMcfe per day in new production, net to our interest. For 2006, we plan to continue exploration and development programs in both the Uinta and the DJ Basins in an effort to expand the known producing areas and to test new ideas.

Other. As of December 31, 2005, other primarily represents 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/day during 2005. Our interests in the Oakvale Dome Field together with interests in the Wausau Field, located in Wayne County Mississippi, were acquired in October 2004 as part of our acquisition of 10 offshore blocks in the shallow waters of the Central Gulf of Mexico. We sold our interest in the Wausau Field during 2005. 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 from time to time in the future.

Table of Contents

Natural Gas and Oil Reserves

The following table summarizes the estimates of our historical net proved reserves as of December 31, 2005, 2004 and 2003, and the present values attributable to those reserves at those dates. For the year ended December 31, 2005, the reserve data and present values were fully engineered by independent petroleum engineering consultants Netherland, Sewell & Associates, Inc. For the years ended December 31, 2004 and 2003, reserve data and present values were fully engineered by two independent petroleum engineering firms: Netherland, Sewell & Associates, Inc. and Miller and Lents, Ltd., with each evaluating approximately 80% and 20%, respectively, of the total reserve quantities during 2004 and 75% and 25%, respectively, during 2003.

		As of December 31,	
Net Proved Reserves:	**2005**[(1)]	**2004**	**2003**
		(in thousands)	
Natural gas (MMcf)	793,074	749,114	709,883
Oil and natural gas liquids (MBbls)	11,291	7,335	7,481
Total (MMcfe)	860,820	793,124	754,769
Standardized measure of discounted future net cash flows [(2)]	$1,967,024	$1,440,055	$1,504,406

(1) At December 31, 2005, net proved reserves attributable to our Gulf of Mexico assets totaled 244,596 MMcfe and included 196,488 MMcf of natural gas and 8,018 MBbls of oil and natural gas liquids. The pending sale of the Texas portion of our Gulf of Mexico assets represents approximately 58,463 MMcfe and includes 54,728 MMcf of natural gas and 622.5 MBbls of oil and natural gas liquids.

(2) The standardized measure of discounted future net cash flows has been calculated in accordance with SFAS 69, Disclosures About Oil and Gas Producing Activities (see 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 hedging program. Year-end prices per Mcf of natural gas used in making the standardized measure determinations as of December 31, 2005, 2004 and 2003 were $8.15, $5.68 and $5.79, respectively. Year-end prices per Bbl of oil used in making the standardized measure determinations as of December 31, 2005, 2004 and 2003 were $53.27, $41.67 and $30.27, respectively.

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.*

-7-

Table of Contents

Drilling Activity

We engage in numerous drilling activities on properties presently owned by us and intend to drill or develop other properties we may acquire in the future. The following table sets forth the results of our drilling activities for the years ended December 31, 2005, 2004 and 2003. 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
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 areas 2005	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 areas 2004	29	26.8	9	6.0	148	116.7	25	21.0	177	143.5	34	27.0	211	170.5
2003														
South Texas	3	3.0	3	3.0	53	51.3	18	17.5	56	54.3	21	20.5	77	74.8
Arkoma Basin			1	0.4	46	28.6	4	2.5	46	28.6	5	2.9	51	31.5
Other onshore					2	2.0			2	2.0			2	2.0
Gulf of Mexico	6	2.4	8	3.6	3	2.0			9	4.4	8	3.6	17	8.0
Total areas 2003	9	5.4	12	7.0	104	83.9	22	20.0	113	89.3	34	27.0	147	116.3

As of December 31, 2005, we were drilling or participating in the drilling of 13 gross (8.86 net) wells. Of these wells, through March 1, 2006, 9 gross (7.0 net) wells have been determined to be successful, with the remaining 4 gross (1.8 net) wells still in progress as of the date of our Annual Report.

Productive Wells

The following table sets forth the number of productive wells in which we owned an interest as of December 31, 2005. Productive wells consist of producing wells and wells capable of production, including 62 wells located in the Rocky Mountains (50 in the DJ Basin and 12 in Uinta), awaiting connections at December 31, 2005. Wells that are completed in more than one producing horizon are counted as one well. As operator, we are designated the party under the terms of an operating agreement that manages the day-to-day operations of the well.

	As of December 31, 2005									
	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	743	707.8	108	14.9	21	12.4			872	735.1
Arkoma Basin	289	197.1	122	26.1					411	223.2
East Texas	48	38.7	1	0.4	3	2.2			52	41.3
Rocky Mountains	117	96.2	42	21.0	2	1.0			161	118.2
Other			2	1.1					2	1.1
Total onshore	1,197	1,039.8	275	63.5	26	15.6			1,498	1,118.9
Gulf of Mexico	91	71.9	54	15.4	18	14.1	6	0.9	169	102.3
Total	1,288	1,111.7	329	78.9	44	29.7	6	0.9	1,667	1,221.2

Table of Contents

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, 2005. 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, 2005					
	Undeveloped		Developed		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
South Texas	14,606	12,978	107,299	81,672	121,905	94,650
Arkoma Basin	25,624	8,857	59,707	28,322	85,331	37,179
East Texas	5,547	3,488	10,746	6,670	16,293	10,158
Rocky Mountains	703,196	543,380	41,943	22,937	745,139	566,317
Other onshore			1,740	620	1,740	620
Total onshore	748,973	568,703	221,435	140,221	970,408	708,924
Gulf of Mexico	227,062	159,521	314,886	200,926	541,948	360,447
Total	976,035	728,224	536,321	341,147	1,512,356	1,069,371

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, 2005									
	2006		2007		2008		2009		2010	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
South Texas	3,686	3,064	5,399	5,240	1,111	1,076				
Arkoma Basin			2,816	932			614	238	4,088	1,154
East Texas			3,592	2,734	60	40				
Rocky Mountains	193,559	129,257	110,287	84,391	150,362	120,943	35,399	27,213	16,171	5,713
Total onshore	197,245	132,321	122,094	93,297	151,533	122,059	36,013	27,451	20,259	6,867
Gulf of Mexico	32,257	24,897	46,181	37,921	62,824	34,756	42,280	26,324	15,000	12,500
Total	229,502	157,218	168,275	131,218	214,357	156,815	78,293	53,775	35,259	19,367

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 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 and results of operations. For a list of our purchasers that accounted for 10% or more of our natural gas and oil revenues during the preceding last three calendar years, see Notes to Consolidated Financial Statements Note 8 Sales to Major Customers.

We enter into hedging transactions with 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.

Table of Contents

Transportation space on these gathering systems and pipelines is occasionally 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 any title 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 a title opinion. 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, the demand for natural gas increases during the winter months as a result of heating applications and decreases during the summer months. Seasonal anomalies such as mild winters or cool summers sometimes lessen this fluctuation. 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 recent 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.

Employees

As of December 31, 2005, we had 167 full time employees, 134 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.

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 Alabama. 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 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 tribes, 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 indefinitely into the future nor can we determine what affect, 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 at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. In offshore Federal waters, the Outer Continental Shelf Lands Act requires every permit or other grant of authority for the transportation of oil or gas by pipeline on or across the Outer Continental Shelf to require the pipeline to provide open and nondiscriminatory access, but does not authorized 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 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, 2005, we did not incur any material capital expenditures for environmental control facilities. As of the date of our Annual Report, we are not aware of any environmental issues or claims that will require material expenditures during 2006 and 2007 or that will have a material impact on our financial position or results of operations.

Table of Contents

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 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

Table of Contents

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.

Table of Contents

Item 1A. Risk Factors

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:

§ the domestic and foreign supply of natural gas and oil;

§ weather conditions;

§ the price of foreign imports;

§ overall domestic and global economic conditions;

§ terrorist attacks or military conflicts;

§ political and economic conditions in oil producing countries;

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

§ the level of 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 92% of our total proved reserves at December 31, 2005 were natural gas.

Our ability to sell assets and replace revenues generated from any sale of our Gulf of Mexico properties depends upon market conditions and numerous uncertainties.

In November 2005, we announced our intent to explore the sale of our Gulf of Mexico assets and to shift our operating focus onshore. While we have announced the pending sale of the Texas portion of our Gulf of Mexico assets and the sale process for the remaining offshore assets is ongoing, there can be no assurance that we will sell our remaining offshore assets. Although we plan to reinvest the proceeds from any sale of our Gulf of Mexico assets in onshore producing assets, there can be no assurance that we will be able to find suitable properties on attractive terms.

Our operating revenues and cash flows are expected to decrease 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.

Our level of indebtedness may limit our financial flexibility.

As of December 31, 2005, we had long-term indebtedness of $597 million, with $422 million drawn under our revolving bank credit facility and $175 million of 7% senior subordinated notes. Our long-term indebtedness represented 46% of our total book capitalization at December 31, 2005. As of the date of this Annual Report, outstanding borrowings under our revolving bank credit facility were $407 million.

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

- 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 onshore assets because these assets have been mortgaged to secure borrowings under our revolving bank credit facility;

§ 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.

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 will 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 performance at the time we need capital.

We may be required to take 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, increases in our estimates of development 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, calculated using prevailing prices on the last day of the period. 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 writedown 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. 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. The book value of our proved natural gas and oil properties increased in 2005 as a function of our higher acquisition, exploration and development costs for the year and the increase in future development costs associated with reserves added during the year. To the extent our finding and development costs continue to increase as we expect, we will become more susceptible to ceiling test writedowns in low price environments.

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

The amount of borrowings available to us under our revolving 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 $600 million and is expected to be reduced upon completion of the pending sale of the Texas portion of our Gulf of Mexico assets and likely would be reduced further upon any sale of our remaining Gulf of Mexico assets. 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 revolving 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 financial losses and reduced our income and may continue to do so in the future.

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 hedging arrangements for a significant portion, between 70% and 80%, of our production. As of the date of our Annual Report, we have approximately 250 MMBtu per day, or approximately 75% of our projected 2006 natural gas production hedged and less than 10%, or 30 MMBtu per day and 20 MMBtu per day, respectively, hedged for 2007 and 2008. In connection with the possible divestiture of our Gulf of Mexico assets, and after taking into account the impact of any such sale on our production levels and any acquisitions that appear imminent at the time of any such sale, we may and may be required under our revolving bank credit facility to liquidate a portion of our 2006 hedge position. Specifically, if we were to sell all of our Gulf of Mexico assets, we estimate that we would liquidate at least 70 MMBtu per day. Depending on prices in effect at the time of liquidation, we could be required to make a significant payment to settle the open contracts, which payment we would expect to finance with proceeds from the sale of any Gulf of Mexico assets and/or borrowings under our revolving bank credit facility.

The derivative instruments that we typically employ require us to make cash payments to the extent the NYMEX price exceeds a predetermined price, thereby limiting our ability to realize the benefit of increases in natural gas prices. As we typically tie our derivative instruments to NYMEX prices as opposed to the local indices where we sell our gas, our hedging strategy may not protect our cash flows if basis differentials increase between the NYMEX and local prices. Under SFAS 133, our income could be negatively affected to the extent our NYMEX-based derivative instruments are deemed ineffective in hedging price fluctuations at our sales points. Historically, our basis differential between the NYMEX price and the Houston Ship Channel index, where approximately 30% of our production is hedged, averaged not more than $0.30 per MMBtu. However, market conditions and extreme price volatility during the fourth quarter of 2005 created in the aftermath of Hurricanes Katrina and Rita, caused our average basis differential to increase to $2.40 per MMBtu, causing us to realize significantly lower sales prices for natural gas during the fourth quarter of 2005. In addition, this extreme widening of the basis differential between NYMEX and Houston Ship Channel created a loss of correlation. As a result, our hedged production allocated to the Houston Ship Channel index failed to qualify for hedge accounting. We were required to recognize the change in the fair value of these contracts during the fourth quarter of 2005 as an unrealized gain of $26.1 million ($16.9 million net of tax) in fourth quarter earnings. In future periods, our earnings could fluctuate significantly if these contracts can not be re-designated as cash flow hedges as the mark-to-market changes in the fair value at the end of each future period would be recognized in the income statement. Further, if we experience a sustained material interruption in our production, we might be forced to satisfy all or a portion of our hedging obligations without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial reduction in our liquidity as was the case during the fourth quarter of 2005 when offshore production was significantly curtailed due to Hurricanes Katrina and Rita. Finally, another risk of hedging activities is that the counterparty in any derivative transaction cannot or will not perform under the hedge contract and that we will not realize the benefit of the hedge.

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. Likewise, our offshore production (as to which we are pursuing a sale) is generally characterized by small reservoirs with high porosity and permeability that produce at very high rates but typically deplete rapidly. 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. As commodity prices have continued to remain strong, the costs for materials, equipment and services have increased. 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 areas, particularly in our focus areas of South Texas and the Rocky Mountain regions, and we believe these values may continue to increase in 2006. 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 in response to falling prices, which would impair our profitability.

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 revolving 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 will 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 2005 and 2004, we incurred downward revisions of our proved reserves of 60 Bcfe and 20 Bcfe, respectively, either from proved undeveloped reserves that were determined to be depleted or otherwise not recoverable, or from production performance indicating less gas in place or smaller reservoir size than initially estimated.

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;

§ 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 as 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 2005, we generated approximately 97% of our production from three primary areas of operation, with 43% from South Texas, 40% from offshore Gulf of Mexico and 14% from the Arkoma Basin. As we pursue divesting our Gulf of Mexico assets, our operations could become even more geographically concentrated. 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 our offshore operations, 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. During 2005, we estimate that approximately 10.6 Bcfe of offshore production was either curtailed or delayed as a result of infrastructure damage to third party pipelines and processing facilities caused by Hurricanes Katrina and Rita that struck the Texas and Louisiana coasts during August and September.

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 two to 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 in 2006. If current utilization rates continue at levels seen during 2005 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. During 2005, we estimate that approximately 10.6 Bcfe of offshore production was curtailed and delayed due damage to third-party pipelines and processing facilities as a result of damage to Gulf of Mexico infrastructure after Hurricanes Katrina and Rita that struck the Texas and Louisiana coasts during August and September of 2005. 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.

Our 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.

Our ability to maximize tax efficiencies with tax free asset exchange transactions following the pending sale of our Gulf of Mexico assets is uncertain.

There are numerous uncertainties surrounding our ability to reinvest the proceeds from the pending sale of the Texas portion of our Gulf of Mexico assets and any subsequent sale of the remaining portion of our offshore assets into onshore natural gas and oil assets, including our ability to structure the reinvestment in such a manner and within the required time frame such that it qualifies as a tax-free exchange under Section 1031 of the Internal Revenue Code. In the event we are not able to reinvest the proceeds from the pending sale and any subsequent sale within the time period prescribed under Section 1031, we will bear the cost of the resulting tax liability, which could be significant.

Our investments in the Rocky Mountains may not be successful.

Our future growth plans rely in part on establishing significant production and reserves in the Rocky Mountains, particularly the Uinta Basin in Utah and the DJ Basin in Colorado. To date, we lack sufficient production history from these areas to accurately estimate the likelihood that our endeavors will yield meaningful reserves and production with an acceptable rate of return. Certain of our exploration objectives in the Rocky Mountain area involve geology types and mechanical operations that differ substantially from our historic operations in South Texas and the Arkoma Basin. In addition, operations in the Rocky Mountain region present unique operational challenges, such as more acute transportation constraints, higher pricing differentials, and more extensive regulatory oversight. Increased drilling in the vicinity of our Rocky Mountain acreage has also resulted in the Bureau of Land Management (BLM) increasingly requiring the preparation of environmental assessments or more comprehensive environmental impact statements, as a condition to conducting operations on certain lands that the BLM administers. Any or all of these contingencies could delay or halt our drilling activities or the construction of ancillary facilities necessary for production, which would prevent us from developing our property interests in the Rocky Mountains as planned and impede our growth.

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.

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 may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions.

Provisions in our Charter, Agreements, Stockholder Rights Plan and Delaware Law May Inhibit a Takeover of Houston Exploration.

Under our Restated Certificate of Incorporation, our Board of Directors is authorized to issue shares of our common or preferred stock without approval of our stockholders. Issuance of these shares could make it more difficult to acquire our company without the approval of our Board of Directors as more shares would have to be acquired to gain control. We also have a stockholder rights plan, commonly known as a poison pill, that entitles our stockholders to acquire additional shares of our company, or a potential acquirer of our company, at a substantial discount from market value in the event of an attempted takeover without the approval of our Board. In 2005, we amended our rights plan to increase the ownership triggering threshold from 10% to 15%. The indenture governing our 7% senior subordinated notes due 2013 also contains change of control provisions that, among other things, allow the holders of the notes to require us to repurchase them at 101% of their principal amount, and a change of control constitutes a default under our revolving bank credit facility. Finally, Delaware law imposes restrictions on mergers and other business combinations between us and a holder of 15% or more of our outstanding common stock under certain circumstances. These provisions may deter hostile takeover attempts that could result in an acquisition of us that would have been financially beneficial to our stockholders.

Item 1B. Unresolved Staff Comments

None.

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

Item 3. Legal Proceedings

We currently are not a party to any material pending legal or governmental proceedings, other than ordinary and routine litigation incidental to our business. While the ultimate outcome and impact of this litigation cannot be predicted with certainty, our management believes that the resolution of any such litigation will not have a material adverse effect on our financial condition or results of operations.

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, 2005.

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 sales prices for each calendar quarterly period from January 1, 2004, through December 31, 2005 as reported on the New York Stock Exchange:

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

Year Ended December 31, 2004	High	Low
First Quarter	$45.85	$35.79
Second Quarter	52.47	41.40
Third Quarter	59.79	48.30
Fourth Quarter	61.80	53.65

As of March 1, 2006, 29,067,430 shares of common stock were outstanding, and we had approximately 51 stockholders of record and approximately 30,000 beneficial owners.

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, retirement of debt or repurchase of our common stock. In addition, our revolving bank credit facility and the indenture governing our 7% senior subordinated notes due June 15, 2013, 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.

Table of Contents

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, 2005. 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,				
	2005	**2004**	**2003**	**2002**	**2001**
	(in thousands, except per share data)				
Income Statement Data:					
Revenues:					
Natural gas and oil revenues	$ 620,271	$ 649,087	$ 491,440	$ 344,295	$ 387,156
Other	1,272	1,352	1,312	1,086	1,353
Total revenues	621,543	650,439	492,752	345,381	388,509
Expenses:					
Lease operating expense	67,796	55,925	47,072	33,976	25,291
Severance tax	18,121	11,933	15,958	9,487	11,035
Transportation expense	11,883	11,819	10,387	9,317	7,652
Asset retirement accretion expense(1)	5,278	4,902	3,668		
Depreciation, depletion and amortization	295,351	265,148	197,530	171,610	128,736
Writedown in carrying value					6,170
General and administrative, net	38,378	32,899	19,542	13,077	17,110
Total operating expenses	436,807	382,626	294,157	237,467	195,994
Income from operations	184,736	267,813	198,595	107,914	192,515
Other (income) expense (2)	142	(1,058)	(15,746)	(9,070)	119
Interest expense, net	16,535	9,455	8,342	7,398	2,992
Income before income taxes	168,059	259,416	205,999	109,586	189,404
Income tax provision	62,890	96,592	72,187	39,092	66,803
Income before cumulative effect of change in accounting principle	$ 105,169	$ 162,824	$ 133,812	$ 70,494	$ 122,601
Cumulative effect of change in accounting principle (3)			(2,772)		
Net income	$ 105,169	$ 162,824	$ 131,040	$ 70,494	$ 122,601
Earnings per share:					
Basic:					
Income per share before cumulative effect of change in accounting principle change	$ 3.66	$ 5.50	$ 4.30	$ 2.31	$ 4.06

Cumulative effect of change in accounting principle (3)						(0.09)				
Net income per share basic	$	3.66	$	5.50	$	4.21	$	2.31	$	4.06
Diluted:										
Income per share before cumulative effect of change in accounting principle	$	3.62	$	5.44	$	4.29	$	2.28	$	4.00
Cumulative effect of change in accounting principle (3)						(0.09)				
Net income per share diluted	$	3.62	$	5.44	$	4.20	$	2.28	$	4.00
Weighted average shares basic		28,707		29,616		31,097		30,569		30,228
Weighted average shares diluted		29,037		29,932		31,213		30,878		30,645
Ratio of earnings to fixed charges (4)		7.2x		15.0x		13.6x		7.6x		12.8x

	Years Ended December 31,				
	2005	2004	2003	2002	2001
	(in thousands)				
Cash Flow Data:					
Net cash provided by operating activities	$460,509	$527,141	$381,969	$243,601	$355,311
Net cash used in investing activities	727,003	509,922	452,959	252,857	365,556
Net cash provided by (used in)financing activities	255,896	(1,211)	55,528	17,668	9,189

	At December 31,				
	2005	2004	2003	2002	2001
	(in thousands)				
Balance Sheet Data:					
Working capital (deficit) (5)	$ (214,525)	$ (31,884)	$ (36)	$ 10,550	$ 34,314
Property, plant and equipment, net	2,018,340	1,548,256	1,371,129	1,022,414	938,761
Total assets	2,361,624	1,722,577	1,509,065	1,151,068	1,059,092
Long-term debt and notes	597,000	355,000	302,000	252,000	244,000
Stockholders equity	693,138	782,920	735,534	592,789	565,881

(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 2005, 2004, 2003 and 2002, other income includes $2.7 million, $1.2 million, $21.6 million and $9.1 million, respectively, representing recoupments of prior period 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. See Note 9 Commitments and Contingencies. In addition, for 2005, other income and expense includes 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 includes $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 includes $5.9 million in expenses incurred pursuant to the early redemption of our $100 million $8^5/_8$% notes in June 2003. For 2001, other expense of $0.2 million, represents nonrecurring expenses incurred in connection with a strategic review of alternatives for KeySpan s investment in our company, including the possible sale of all or a portion of Houston Exploration.

(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 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 for

calculation.

(5) The working capital deficit during at December 31, 2005, 2004 and 2003, was 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.

Table of Contents

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 concentrating on growing reserves and production through 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 began exploring for natural gas and oil on behalf of KeySpan Corporation, our then parent company. KeySpan is a diversified energy provider whose principal natural gas distribution and electric generation operations are located in the Northeastern United States. In September 1996, we completed our initial public offering and sold approximately 31% of our shares to the public. Through three separate transactions, the first in February 2003 and last in November 2004, KeySpan completely divested its investment in the common stock of our company. See Note 3 Stockholders Equity for a complete description of these three transactions.

At December 31, 2005, we had operations in five producing regions within the United States: South Texas; the Arkoma Basin of Arkansas and Oklahoma; East Texas; the Uinta and DJ Basins in the Rocky Mountains; and the Gulf of Mexico.

Our total net proved reserves as of December 31, 2005 were 861 billion cubic feet equivalent or Bcfe, with onshore reserves totaling 616 Bcfe. Our reserves are fully engineered on an annual basis by independent petroleum engineers. Approximately 64% of our proved reserves at December 31, 2005, were classified as proved developed. Our daily production during 2005 averaged 313 million cubic feet of natural gas equivalent or MMcfe and was significantly curtailed during the last four months of 2005 and into the first quarter of 2006 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. 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. During 2005, 2004 and 2003, the use of derivative instruments prevented us from realizing the full benefit of upward price movements and may continue to do so in future periods.

We operate as one segment as all of our assets are based in North American and each of our operating areas has similar economic characteristics and each meets the criteria for aggregation as defined in the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) 131, Disclosures about Segments of an Enterprise and Related Information.

Shift in Operating Focus and Pending Sale of the Texas Portion of Our Gulf of Mexico Assets

In November 2005, we announced our intent to explore the sale of our Gulf of Mexico assets and to shift our operating focus onshore. At December 31, 2005, our offshore reserves totaled 245 Bcfe, or 28% of our total proved reserves. Historically, production from our offshore properties has averaged 40% to 45% of total production. Our offshore properties are located in the shallow waters of the Outer Continental Shelf. Key producing properties are located in the western and central Gulf of Mexico and include the Mustang Island, Matagorda Island, Galveston Island, High Island, East Cameron, West Cameron, Eugene Island and Main Pass areas. At December 31, 2005, we held interests in 136 blocks in federal and state waters, of which 78 were developed. We had a total of 97 producing platforms and production caissons, of which we operated 61. During 2005, offshore production averaged 125 MMcfe/day, and immediately prior to shut-ins caused by Hurricanes Katrina and Rita, averaged an estimated 155

MMcfe/day. For December 2005, offshore production averaged 123 MMcfe per day with several fields still curtailed. On February 28, 2006, we entered into an agreement to sell the Texas portion of our Gulf of Mexico assets to certain partnerships affiliated with Merit Energy Company for $220 million in cash, subject to adjustment and customary closing conditions. The transaction is scheduled to close on or about March 31, 2006, with an effective date of January 1, 2006. We expect to use the proceeds from the sale of the Texas portion of our Gulf of Mexico assets primarily to acquire longer-lived natural gas assets onshore in North America and to repay existing debt. There can be no assurances that we will be able to find suitable properties on attractive terms. Our operating revenues and cash flows are expected to decrease 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. Where possible, we plan to structure our asset reinvestment to minimize taxes on any gain realized from the sale. The sale process with respect to our remaining Gulf of Mexico assets is ongoing. If a sale is not consummated, we expect to continue to operate and may consider other strategic alternatives with respect to these remaining offshore assets. The Texas portion of our Gulf of Mexico assets accounted for approximately 18% of our 2005 production and represented 58.5 Bcfe, or 7% of our total proved reserves, at December 31, 2005. At December 31, 2005, we held interests in 70 blocks in offshore Texas state and federal waters, of which 33 were developed. Our assets included 38 producing platforms and production caissons.

The pending sale of the Texas portion of our Gulf of Mexico assets and any subsequent sale of the remaining portion of our Gulf of Mexico assets will result in the reclassification of the fair value of the derivative obligations allocated to offshore production from accumulated other comprehensive income to earnings. At December 31, 2005, the fair value of derivative obligations allocated to offshore production for years 2006, 2007 and 2008 was a liability of $182.7 million ($118.0 million net of tax) which approximates the amount deferred in accumulated other comprehensive income at the end of the period. The ultimate amount of this reclassification and possible charge against earnings will depend on the fair value of the obligations at the time that receipt of offshore production allocated to these hedges no longer appears probable. This reclassification and possible charge to earnings will not affect cash flow.

In connection with the possible divestiture of our Gulf of Mexico assets, and after taking into account the impact of any such sale on our production levels and any acquisitions that appear imminent at the time of any such sale, we may and may be required under our revolving bank credit facility to liquidate a portion of our 2006 hedge position allocated to offshore production. If we were to sell all of our Gulf of Mexico assets, we estimate that we would liquidate at least 70 MMBtu per day of hedged production. Depending on prices in effect at the time of liquidation, we could be required to make a significant payment to unwind and settle the open contracts, which payment we would expect to finance with proceeds from the sale of any Gulf of Mexico assets and/or borrowings under our revolving bank credit facility.

Recent Acquisition

As part of the plan to shift our operational focus onshore, 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 revolving bank credit facility. 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, the proved reserves attributed to these properties 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 to be acquired. We operate 100% percent of the proved reserves with an average working interest of 60%.

Industry Outlook

We currently operate in North America and we believe this region is maturing and production growth is slowing or possibly declining. While new discoveries are still being made in North America, the frequency and size of these discoveries is declining as finding and developing costs are increasing. We believe domestic natural gas and oil production may be at or near its peak and can be expected to decline in the future, with the exception of relatively unexplored onshore regions such as the Rocky Mountains.

Our future success in growing our reserve base at an acceptable finding cost will depend in large part on our ability to acquire new proved reserves and unevaluated acreage which we can explore and exploit. We maintain an active acquisition program and expect to continue to devote significant resources to identifying and pursuing both tactical acquisitions that are designed to expand our operations within an existing core area as well as strategic acquisitions involving one or more new onshore regions.

We anticipate that the continued decline of the North American gas basins will lead to higher cost structures throughout our industry. We believe that the cost of finding, developing and producing new natural gas and oil reserves through exploration and development operations will rise as the industry makes fewer discoveries and such discoveries generally

Table of Contents

will be of smaller average reserve size. In addition, the acquisition market for natural gas properties has become extremely competitive as producers vie for additional production and expanded drilling opportunities in North America. For full cost companies such as ours, increases in both acquisition and finding and development costs are expected to yield higher depreciation, depletion and amortization rates and ultimately could increase the likelihood of a writedown in the carrying value of our natural gas and oil properties if commodity prices fall substantially below current levels as we continue to add costs to our pool at higher rates with the addition of fewer new reserves to the amortization base. In addition, we expect drilling costs and lease operating expenses to continue to increase as producers are required to make operational enhancements to maintain aging fields.

Natural gas is a commodity. As such, the price that we receive for the natural gas we produce is largely a function of market supply and demand. Demand for natural gas in the United States has increased dramatically over the last ten years, as many industrial users have gradually switched to a cleaner burning and historically cheaper fuel. Demand will be impacted by general economic conditions, estimates of gas in storage, weather and other seasonal conditions, including hurricanes and tropical storms.

Market conditions involving over or under supply of natural gas can result in substantial price volatility. Continued concerns over the United States ability to meet its longer-term gas needs from declining domestic supply have resulted in sustained prices above $5.00 throughout 2003, 2004 and 2005. As a direct result of the strong commodity prices during the last three-year period, we were able to generate substantial cash flows to fund our exploration and development program. However, historically, commodity prices have been very volatile, and we expect the volatility to continue in the future. In fact, the NYMEX closing price for natural gas changed from $6.123 per MMbtu for June 2005 to $13.832 per MMBtu for October and again to $7.112 per MMBtu for March 2006. As a result, we cannot accurately predict future natural gas and oil prices, and, therefore, we cannot determine what effect increases or decreases will have on our future revenues and cash flows. A substantial or extended decline in natural gas and oil prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of natural gas and oil reserves that may be economically produced and our ability to access capital markets. Our continued growth and profitability depends on the strength of natural gas prices and our ability to acquire, find and develop new reserves at economical costs.

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 Note 1 Summary of Organization and Significant Accounting Policies of Item 8 contained in this Form 10-K for a discussion of our significant accounting policies.

Proved Reserves. Our reserves are fully engineered 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, 2005 and 2004, we revised our proved reserves downward from prior years reports by approximately 60 Bcfe and 20 Bcfe, respectively, due to proved undeveloped reserves that were determined to be depleted or otherwise not recoverable, 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, wells pending determination and related capitalized interest. 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 in our unevaluated property balance on a quarterly basis for possible impairment or reduction in value. We believe that substantially all of the costs included in our unevaluated property balance will be evaluated in the next four years.

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. Historically, our derivative contracts have qualified for hedge accounting under SFAS 133, Accounting for Derivative Instruments and Hedging Activities, as amended. Accordingly, we reflect the fair market value of our derivative instruments on our balance sheet. Fair value is accessed and measured and is estimated by obtaining independent market quotes from counterparties, as well as utilizing the Black-1976 option valuation model that is 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 access and measure the ineffectiveness of our open contracts at the end of each period. If open contracts cease to qualify for hedge accounting, the mark-to-market change in the fair value is recognized in the income statement. Loss of hedge accounting and cash flow designation will cause volatility in earnings. The fair values we report in our financial statements change as estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

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, Accounting for Stock-Based Compensation. Under the fair value recognition provisions of SFAS 123, 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. See New Accounting Pronouncements below.

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.

New Accounting Pronouncements

On December 16, 2004, the FASB issued Statement 123 (revised 2004), Share-Based Payment (SFAS 123(R)), which requires the measurement and recognition of compensation expense for all stock-based compensation payments and the current accounting under SFAS 123, Accounting for Stock-Based Compensation, and supersedes Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees. For us, SFAS 123(R) is effective for our first fiscal year beginning after June 15, 2005, or January 1, 2006.

On January 1, 2003, we adopted the fair value expense recognition provisions of SFAS 123 as amended by SFAS 148, Accounting for Stock-Based Compensation Transition and Disclosure using the prospective method as defined by the SFAS 148. As a result, we have recognized compensation expense for all stock options granted subsequent to January 1, 2003, with no expense recognized for grants made prior to 2003. With the adoption of SFAS 123(R), we will recognize compensation expense over the remaining service period for the unvested portion of all options granted during 2001 and 2002. All options granted prior to 2001 are fully vested. We adopted SFAS 123(R) on January 1, 2006, using the modified version of the prospective application. We plan to continue using the Black-Scholes option pricing model to estimate the fair value of our options on the date of grant. Based on current estimates, we expect to incur additional stock compensation expense for grants made prior to our initial adoption of SFAS 123, and not vested as of January 1, 2006 of $2.0 million ($1.5 million net of amounts capitalized) during 2006 and $0.9 million ($0.7 net of amounts capitalized) during 2007, with all prior awards being fully expensed by December 31, 2007. We do not believe the adoption of SFAS 123(R) will have a material impact on our financial statements.

In March 2005, the SEC released Staff Accounting Bulletin (SAB) 107 providing additional guidance in applying the provisions of SFAS 123(R), Share-Based Payment. SAB 107 should be applied when adopting SFAS 123(R) and addresses a wide range of issues, focusing on valuation methodologies and the selection of assumptions. In addition, SAB 107 addresses the interaction of SFAS 123(R) with existing SEC guidance.

Overview of 2005 Results

Our results for 2005 were significantly impacted by the physical damage to the Gulf of Mexico infrastructure and the resulting market uncertainties caused by Hurricane Katrina in August and Hurricane Rita in September. Rita s path cut directly through our Gulf of Mexico operations. While our physical facilities incurred relatively minor damage, our production during the last four months of the year was significantly curtailed primarily as a result of damage to third party pipelines and processing facilities. Key projects scheduled to add significant new production during the third and fourth quarters of 2005 were further delayed. Curtailed supply throughout the Gulf of Mexico created unprecedented price movements in the natural gas markets. NYMEX prices for natural gas reached record levels which resulted in record revenues that could not be realized in earnings because a significant percentage (more than 85% during the fourth quarter of 2005 as a result of offshore curtailments) of our natural gas production was hedged well below these record prices. In addition, during the fourth quarter of 2005, the basis differential between NYMEX and the Houston Ship Channel widened from an average of $0.30 per MMBtu to an average of $2.40 per MMBtu. Because approximately 30% of our production is allocated to the Houston Ship Channel index, we realized lower sales prices.

As commodity prices continued to increase from prior year levels, so did activity levels across the industry, creating an increase in the demand for materials, equipment, rigs and services. As a result, we experienced a significant increase in our finding and development costs as well as our lease operating expenses during 2005. These factors, combined with an increase in debt were the primary drivers behind results of operations, net income and cash flows during 2005. During 2005:

- § We incurred relatively minor structural damage from Hurricanes Katrina and Rita and expect to spend a maximum of $35 million for hurricane related repairs. We anticipate these losses in excess of our deductible will be covered by insurance. As we do not carry business interruption insurance, the delay of revenues resulting from curtailed and delayed production is not covered. We estimate the curtailment of production and drilling delays resulting directly from the storms impacted operating revenues in 2005 by an estimated $132 million. Revenues are expected to be further impacted during the first quarter of 2006 as we wait for repairs to third-party pipelines and processing facilities, with restoration expected by the end of the first quarter of 2006;

- § We announced our intent to explore the sale of our Gulf of Mexico assets and to shift our operating focus onshore. We plan to reinvest the net cash proceeds from the pending sale of the Texas portion of our Gulf of Mexico assets primarily into longer-lived natural gas assets onshore in North America and to retire debt. The pending sale of our offshore Texas assets is expected to close on or about March 31, 2006, with an effective date of January 1, 2006 (see Consolidated Financial Statements, Note 11 Subsequent Events *Pending Sale of Texas Gulf of Mexico Assets*);

- § We generated $105.2 million in net income, a decrease of 35% from $162.8 million in 2004, primarily as a result of lower revenues caused by production curtailments and $264.5 million in net hedge losses combined with higher depreciation, depletion and amortization expense, general and administrative expense and interest expense;

- § We produced 114 Bcfe and our average daily production rate was 313 MMcfe per day compared to 339 Mcfe/day during 2004, a decrease of 8%. We estimate that approximately 10.6 Bcfe, or approximately 30 MMcfe per day on an annualized basis, was deferred by hurricane related curtailments and delays;

- § We increased total net proved reserves by 9% to 861 Bcfe. We added a net 184 Bcfe, which includes 144 Bcfe added through the drill bit and 100 Bcfe added through acquisitions after 60 Bcfe of downward revisions, due primarily to reservoir performance. With the total net additions of 184 Bcfe, we replaced 161% of the 114 Bcfe produced in 2005;

- § We generated $460.5 million in net cash flows from operating activities compared to $527.1 million during 2004, a decrease of 13%;
- § We spent $743.3 million for investments in natural gas and oil properties, an increase of 44% over 2004. Our 2005 expenditures included $197.7 million for producing property acquisitions that compares to $149.6 million spent towards acquisitions in 2004, an increase of 32%;
- § We increased our outstanding borrowings under our revolving bank credit facility by a net $242 million, in part to fund our acquisitions and in part to fund cash requirements for the settlement of derivative contracts;
- § We drilled 336 wells, of which 298, or 89%, were successful with 12 offshore, 16 in East Texas, 82 in South Texas, 60 in Arkoma and 128 in the Rockies;

Table of Contents

§ We successfully integrated the Gulf of Mexico producing properties acquired in September and October 2004 from BP Exploration & Production Inc. and Orca Energy, L.P., respectively and successfully completed key development projects at Main Pass 264 and Eugene Island 331;

§ We drilled or participated in drilling of three offshore discoveries that were considered deep shelf prospects. The successful wells were drilled at West Cameron 75, West Cameron 77 and West Cameron 62. Additional exploratory successes included Galveston 210 and East Cameron 23;

§ We expanded our onshore exploration efforts in the DJ Basin with one rig drilling throughout the year and brought on-line our first group of wells during the third quarter of 2005;

§ We continued our exploration and exploitation efforts in the Uinta Basin with one rig drilling throughout the year and partnered with two separate groups to spread our risk and accelerate our efforts. At year-end, we had three rigs drilling on our acreage. We had a discovery north of the Natural Buttes Field and the well is producing approximately 26 Bbls per day, net to our interests, as of the date of this Annual Report;

§ We extended our development efforts in the North Roleta Field, located in South Texas, southwest of our operations in the Charco Field, where we began to assemble acreage and drilled a discovery well in 2004. We successfully drilled and completed eight of ten wells and added approximately 17.5 MMcfe per day in production, net to our interests;

§ We expanded our East Texas acreage through a series of three related acquisitions totaling $38.7 million and added an estimated 38 Bcfe in proved reserves. We successfully integrated these producing properties, added two drilling rigs, successfully drilled 16 development wells which added 13 Bcfe in reserves and increased average daily production in the area from 2 MMcfe per day in January 2005 to 8 MMcfe per day in December 2005 (see Note 10 Acquisitions and Dispositions);

§ We acquired producing properties and acreage in four South Texas fields along the Frio and Vicksburg Trends from Kerr-McGee Oil & Gas and Westport at the end of November 2005 for a net $159.0 million and added estimated proved reserves of 62 Bcfe and future exploitation opportunities. We took over operations December 1, 2005 and began to integrate the properties and optimize production rates. Daily production is averaging 10 to 12 MMcfe per day as of the date of this Annual Report. We expect to spud our first well in the Rincon Field in April 2006; (see Note 10 Acquisitions and Dispositions);

§ Our depletion rate for natural gas and oil properties increased from $2.30 per Mcfe during the fourth quarter of 2004 to $3.03 per MMcfe during the fourth quarter of 2005, primarily as a result of an industry wide increase in costs. We spent more during 2005 on a per Mcfe basis to find, develop or acquire new reserves and it is projected to cost more to develop our proved reserves as our future development costs increased by $330 million or 60% in 2005 from prior year end;

§ We incurred $13.7 million in additional general and administrative expenses as a result of special charges, including $5.0 million incurred pursuant to the February 2005 renegotiation of employment agreements with five of our key executive officers, including our Chief Executive Officer, Chief Operating Officer and our then Chief Financial Officer; $4.7 million in outside professional fees attributable to the review of a corporate transaction in the second quarter and an acquisition in the third quarter, both of which 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;

§

As a result of higher market prices for natural gas at December 31, 2005, the fair value of our open derivative contracts increased from a liability of $75.1 million ($48.5 million net of tax) at December 31, 2004, to a liability of $417.7 million ($269.8 million net of tax) at December 31, 2005. During 2005, we incurred a total net loss on our hedging activities of $264.5 million which compares to a total net loss of $70.1 million during 2004. Of our 2005 total net hedging loss, $116.5 million was incurred during the fourth quarter;

§ Our Board of Directors approved a plan for discretionary stock repurchases from time to time up to $200 million of our common stock in conjunction with the possible divesture of all of our Gulf of Mexico assets and subject to market conditions, applicable legal requirements and contractual restrictions, available cash, competing reinvestment opportunities in the acquisition market for oil and gas assets and other factors; and

§ We renegotiated our revolving bank credit facility to increase our banks lending commitments from $450 million to $750 million. Borrowings under the facility are secured by our onshore natural gas and oil assets as well as certain other assets. Our initial borrowing base has been set at $600 million, which is expected to decrease upon completion of the pending sale of the Texas portion of our Gulf of Mexico assets and likely would be reduced further upon any sale of the remaining portion of our Gulf of Mexico assets.

Operating and Financial Results for 2005 Compared to 2004 and Operating and Financial Results for 2004 Compared to 2003

	Year Ended December 31,				Year Ended December 31,			
Summary Operating Information:	**2005**	**2004**	**Variance**		**2004**	**2003**	**Variance**	
	(in thousands, except for price data)							
Natural gas revenues	$ 816,182	$669,294	$ 146,888	22%	$669,294	$522,597	$146,697	28%
Oil revenues	68,631	49,938	18,693	37%	49,938	37,201	12,737	34%
Gain (loss) on settled derivatives	(265,236)	(68,195)	(197,041)	289%	(68,195)	(66,408)	(1,787)	3%
Unrealized gain (loss) derivatives	694	(1,950)	2,644	-136%	(1,950)	(1,950)		
Operating revenues	621,543	650,439	(28,896)	-4%	650,439	492,752	157,687	32%
Operating expenses	436,807	382,626	54,181	14%	382,626	294,157	88,469	30%
Income from operations	184,736	267,813	(83,077)	-31%	267,813	198,595	69,218	35%
Net income	105,169	162,824	(57,655)	-35%	162,824	131,040	31,784	24%
Production:								
Natural gas (MMcf)	105,809	115,855	(10,046)	-9%	115,855	99,965	15,890	16%
Oil (MBbls)	1,417	1,355	62	5%	1,355	1,307	48	4%
Total (MMcfe) [(1)]	114,311	123,985	(9,674)	-8%	123,985	107,807	16,178	15%
Average daily production (MMcfe/d)	313	339	(26)	-8%	339	295	44	15%
Average Sales Prices:								
Natural Gas (per Mcf) unhedged	$ 7.71	$ 5.78	$ 1.93	33%	$ 5.78	$ 5.23	$ 0.55	11%
Natural Gas (per Mcf) realized [(2)]	5.21	$ 5.19	0.02		5.19	$ 4.57	0.62	14%
Natural Gas (per Mcf) all-in [(3)]	5.21	5.17	0.04	1%	5.17	4.55	0.62	14%
Oil (per Bbl) unhedged	48.43	36.85	11.58	31%	36.85	28.46	8.39	29%
Oil (per Bbl) realized [(2)]	48.43	36.85	11.58	31%	36.85	28.15	8.70	31%

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

(2) Includes gains and losses realized on hedge contracts settled for natural gas produced during the period.

(3) Includes both the effect of gains and losses realized on contracts settled for natural gas produced during the period as well as unrealized gains and losses.

Income from Operations

Income from Operations 2005

For 2005, income from operations decreased by $83.1 million, or 31%, as compared to 2004, as operating revenues decreased by $28.9 million or 4% and operating expenses increased by $54.2 million or 14% for the year. Natural gas revenues of $816.2 million were significantly impacted by a $265.2 million cash loss realized on derivative contracts settled during the period of which $164.5 million was incurred during the fourth quarter. Although natural gas prices were consistently strong throughout the first eight months of 2005, even exceeding levels seen in 2004, the market volatility caused by Hurricanes Katrina and Rita during the last four months of the year and the resulting record NYMEX prices for natural gas during this period compounded our hedge losses for the year.

Income from Operations 2004

Production growth and higher realized natural gas prices were the primary factors contributing to our 35% increase in operating income in 2004 over 2003. Increased revenues were offset in part by a 30% increase in operating expenses.

Production Volume 2005 vs. 2004

Production volumes were 8% lower in 2005 compared to 2004, due primarily to curtailments of offshore production 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 we see our existing property base mature. Year-over-year, 2004 onshore volumes include production from our South Louisiana properties sold in February 2004 and our Appalachian Basin properties divested of in June 2004.

Offshore. Daily production rates decreased by 18%, 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.

Production Volume 2004 vs. 2003

The 15% increase in production for 2004 is primarily a result of both production added from Gulf of Mexico properties acquired during the fourth quarter of 2003, as well as newly developed production, both onshore and offshore, from our existing property base.

Onshore. Daily production rates increased 8% from an average of 173 MMcfe per day in 2003 to 186 MMcfe per day in 2004, despite our loss of approximately 8 MMcfe per day as a result of the divesture of our South Louisiana and Appalachian Basin properties during the first half of 2004. The Arkoma Basin was our onshore growth area during 2004. We experienced the full impact of the accelerated drilling program initiated in 2003 that continued throughout 2004 as we added 15 MMcfe per day in newly developed production. With three rigs drilling through the first 10 months of 2004, Arkoma production reached a record of 44 MMcfe per day during the fourth quarter compared to 25 MMcfe per day during the fourth quarter of 2003. For 2004, South Texas production increased to an average of 142 MMcfe per day compared to 140 MMcfe per day 2003.

Average daily production rates for Arkoma and South Texas were negatively impacted during the fourth quarter of 2004 by our operational curtailment. As a result of rising rig rates and service costs during the quarter, we reduced our onshore rig activity to keep capital spending within budgeted levels. In South Texas, we went from six rigs to four and in Arkoma we went from three rigs to one. In addition, we deferred the completion of seven wells in South Texas capable of producing an estimated 11 MMcfe per day, net, and five wells in Arkoma capable of producing an estimated 2 MMcfe per day, net. By the end of January 2005, we had resumed our six-rig program in South Texas and added a second rig in Arkoma.

In the Rockies, 2004 was an exploratory year and our activities were aimed at expanding our acreage position and proving up reserves in several exploration projects on our Uinta Basin acreage acquired in 2003. We drilled a total of 31 wells, 26 in the Uinta Basin, four in the DJ Basin and one in Montana. Of the total drilled, 28 wells or 90% were successful. By December 2004, six of our Uinta Basin wells were producing approximately 1.3 MMcfe per day, net to our interest. At December 31, 2004, production from the remaining 19 of our 25 successful Uinta Basin wells remained delayed, awaiting right-of-way approval for pipeline construction from the Bureau of Land Management (BLM). Subsequent to December 31, 2004, we received approval from the BLM for pipelines on 11 of the wells.

Offshore. We experienced record production growth as average daily rates increased 25% from 122 MMcfe per day during 2003 to an average of 153 MMcfe per day during 2004. We added approximately 41 MMcfe per day in newly developed production, of which an average of 22 MMcfe per day was attributable to development drilling at High Island A283 and East Cameron 56/57 and 148. During the year, we completed and brought on-line seven development wells at High Island A283, two at EC 56/57and one at East Cameron 148. All of these fields were acquired in mid-October 2003, as part of our acquisition of Gulf of Mexico properties. Production from these properties accounted for approximately 71 MMcfe per day of our offshore production during 2004. Partially offsetting the production from our newly acquired properties were declines from existing and maturing fields totaling approximately

40 MMcfe per day, resulting in a net 31 MMcfe per day production increase year-over-year. Because the majority of our fields are located in the Western and Central Gulf of Mexico, Hurricane Ivan in September 2004, had minimal impact on our results for the year. We estimate that during the third quarter, approximately 210,000 Mcfe or 2 MMcfe per day was deferred. All shut-in production was fully restored prior to the end of the third quarter of 2004.

During the fourth quarter of 2004, we experienced production declines at three key fields. In November 2004, the High Island 47 No. 1 well depleted. A third party operates this field and, our working interest is 33%. Prior to depletion, the well produced an average of 5 MMcfe per day to our interest, during 2004. In December 2004, our deep well at High Island 115, the No. 1, was shut-in due to a mechanical problem. A third party operates the well, and, we have a 50% working interest. During 2004, this well contributed an average of 9 MMcfe per day to our total daily production.

Commodity Prices and Effects of Hedging 2005 vs. 2004

For 2005, our average unhedged or sales 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 last four months of 2005 as a result of the spike in NYMEX prices, trading in a range between $11.00 per MMBtu to $14.00 per MMBtu, after Hurricanes Katrina and Rita. Subsequent to December 31, 2005, NYMEX prices fell from the record levels set in the fourth quarter, to closing at $7.112 per MMBtu for March 2006. We expect prices to remain volatile throughout 2006.

Included in natural gas revenues for 2005 is a loss of $264.5 million from natural gas hedging activities, which includes the following items:

§ Cash loss on contracts settled for natural gas produced during the period of $265.2 million ($171.3 million net of tax);

§ As a result of the offshore production shortfall during the fourth quarter caused by the hurricanes, we deferred a $20.6 million loss ($13.3 million net) of tax related to the above cash settlements made during the fourth quarter of 2005 to accumulated other comprehensive income. We expect to recapture the production shortfall during the first quarter of 2006, at which time the $20.6 million will be recognized as a reduction to earnings;

§ Unrealized loss of $46.0 million ($29.7 million net of tax) for the ineffective portion of open contracts at the end of the period that were not eligible for deferral under SFAS 133 due primarily to the basis differentials between the contract price, which is NYMEX based, and the indexed price at the point of sale, 30% of which is allocated to the Houston Ship Channel index; and

§ Unrealized gain of $26.1 million ($16.9 million net of tax) due to the loss of correlation during the fourth quarter of 2005 of the Houston Ship Channel index and the NYMEX price. Our hedged production allocated to the Houston Ship Channel index failed to qualify for hedge accounting and as a result, our Houston Ship Channel contracts were marked-to-market with the change in the fair value during the fourth quarter creating an unrealized gain.

As a result of the cash loss from hedge 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 sales price of $7.71 per Mcf of the year. During 2004, we incurred a hedge loss from natural gas derivatives of $70.1 million, which included an unrealized loss of $1.9 million recognized for ineffectiveness. As a result of the cash loss from hedge 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.

Commodity Prices and Effects of Hedging 2004 vs. 2003

Our average unhedged or sales price for natural gas increased by 11% from $5.23 per Mcf during 2003 to $5.78 per Mcf during 2004. Included in natural gas revenues for 2004 is a loss of $70.1 million from natural gas hedging activities, which includes an unrealized loss of $1.9 million representing the ineffective portion of our derivative instruments that are not eligible for deferral under SFAS 133. As a result of the cash loss from hedging activities, we realized an average natural gas price during 2004 of $5.19 per Mcf that was 90% of or $0.59 lower than our average sales price. During 2003, we incurred a hedge loss from natural gas derivatives of $67.9 million, which is included in natural gas revenues and includes an unrealized loss of $1.9 million recognized for ineffectiveness. As a result of the cash loss from hedging activities, we realized an average price of $4.57 per Mcf that was 87% of, or $0.66 per Mcf lower than our sales price.

Table of Contents

Operating Expenses

	Year Ended December 31,				Year Ended December 30,			
Operating Expenses per Mcfe	**2005**	**2004**	**Variance**		**2004**	**2003**	**Variance**	
Lease operating expense	$ 0.59	$ 0.45	0.14	31%	$ 0.45	$ 0.44	$ 0.01	2%
Severance tax	0.16	0.10	0.06	60%	0.10	0.15	(0.05)	-33%
Transportation expense	0.10	0.10		%	0.10	0.10		%
Asset retirement accretion expense	0.05	0.04	0.01	25%	0.04	0.03	0.01	33%
Depreciation, depletion and amortization	2.58	2.14	0.44	21%	2.14	1.83	0.31	17%
General and administrative, net	0.34	0.27	0.07	26%	0.27	0.18	0.09	50%
Total operating expenses per unit of production	$ 3.82	$ 3.10	0.72	23%	$ 3.10	$ 2.73	$ 0.37	14%

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. During 2004, total operating expenses increased 30% over 2003 primarily as a result of higher depreciation, depletion and non-recurring general and administrative expenses. On a unit production basis, operating expenses increased $0.37 per Mcfe produced, or 14%, from 2003 to 2004.

Lease Operating Expense.

On an absolute dollar basis, lease operating expense for 2005 increased by 21% from 2004 levels. For 2004, lease operating expense increased by 19% from 2003 levels. The year-over-year increases from 2003 to 2004 and from 2004 to 2005 relates 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. We have seen our Gulf of Mexico lease operating expenses increase significantly over the last two-year period 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 the last two years, we have integrated these assets into our Gulf of Mexico base and have worked to reduce overall operating expenses. While we remain committed to minimizing our operating cost structure, we expect to see lease operating expenses continue to increase during the next year as the demand for field services remains strong and as we continue our acquisition activities.

Severance Tax.

Severance tax is a function of volume and revenues generated from onshore production. 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. During 2004, severance tax on an absolute dollar basis, decreased by 25% from 2003. On an Mcfe basis, severance tax decreased by $0.05 or 33% from 2003 to 2004. Despite higher wellhead prices during 2004 as compared to 2003 severance tax expense was lower during 2004 primarily due to severance tax rebates received on our South Texas properties as a result of their high-cost/tight-sand designation.

Depreciation, Depletion and Amortization.

The increase in our depreciation, depletion and amortization expense during 2005 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, due primarily to reservoir performance and 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.

Table of Contents

During 2004, the increase in our depreciation, depletion and amortization expense from 2003 was primarily a result of a higher depletion rate combined with a 15% increase in production for the year. Our depreciation, depletion and amortization rate of $2.14 per Mcfe during 2004 was 17% higher than the $1.83 per Mcfe during 2003. Higher average finding costs per unit were the primary factor in the increase in our depletion rate. In addition, our future development costs at December 31, 2004 increased 48% from estimates at December 31, 2003, primarily as a result of the future development costs relating to several offshore Gulf of Mexico properties acquired in October 2004. For 2004, producing property dispositions resulted in reserve reductions of 63.3 Bcfe. Finally, for 2004, we incurred downward revisions of 19.9 Bcfe, either due to proved undeveloped reserves that were depleted or otherwise not recoverable, or from production performance indicating less gas in place or smaller reservoir size than initially estimated.

Asset Retirement Accretion Expense.

The increase in ARO accretion expense from 2004 to 2005 and from 2003 to 2004 reflects the increase in our abandonment obligations as we drill and acquire new wells, offset in part by dispositions.

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	**2005**	**2004**	**Variance**		**2005**	**2004**	**Variance**	
	(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	(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%

2005 vs 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 Note 5 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 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.

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.

	Absolute Dollars Year Ended December 31,				Unit of Production Mcfe Year Ended December 31,			
General and Administrative Expense	**2004**	**2003**	**Variance**		**2004**	**2003**	**Variance**	
	(in thousands)							
Gross general and administrative expense	$ 49,924	$ 33,980	$ 15,944	47%	$ 0.40	$ 0.32	$ 0.08	25%
Operating overhead reimbursements	(2,188)	(1,559)	(629)	40%	(0.01)	(0.02)	0.01	-50%
Capitalized general and administrative	(14,837)	(12,879)	(1,958)	40%	(0.12)	(0.12)		
General and administrative expense, net	$ 32,899	$ 19,542	$ 13,357	68%	$ 0.27	$ 0.18	$ 0.09	50%

-35-

2004 vs. 2003. For 2004, net general and administrative expenses were up by 69% on an absolute dollar basis from $19.5 million in 2003 to $32.9 million in 2004. Of the $13.4 million increase, $9.5 million related to severance expenses and special incentive payments. A substantial portion of the remaining increase related to changes in accounting for stock-based compensation, as well as continuing professional expenses related to corporate governance compliance. For general and administrative expense on a per-unit of production basis, the additional compensation expenses of $9.5 million resulted in an $0.08 per Mcfe increase for 2004. Absent these additional compensation expenses, gross general and administrative expense for 2004 would have been $0.32 per Mcfe, unchanged from $0.32 per Mcfe in 2003 and net general and administrative expense would have been $0.19 per Mcfe for 2004, an increase of $0.01 per Mcfe or 6%, from 2003. While general and administrative expenses have increased as our company has grown, per unit expense is comparable year-over-year as a result of the increase in our production volume during 2004.

Other Income and Expense, Interest and Taxes

Other Income and Expense.

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%. 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.

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 revolving bank credit facility due to the disposition of our Appalachian Basin assets in June 2004. For 2004, the recognition of other income as a result of the recoupment of prior years expense is considerably less than in 2003 as we were nearing the end of the recoupment process.

	Year Ended December 31,				Year Ended December 31,			
Interest and Average Borrowings	**2005**	**2004**	**Variance**		**2004**	**2003**	**Variance**	
			(in thousands)					
Gross interest	$ 25,301	$ 17,813	7,488	42%	$ 17,813	$ 15,642	$ 2,171	14%
Capitalized interest	(8,766)	(8,358)	(408)	5%	(8,358)	(7,300)	(1,058)	14%
Interest expense, net of capitalized interest	$ 16,535	$ 9,455	7,080	75%	$ 9,455	$ 8,342	$ 1,113	13%
Average total borrowings[1]	$ 388,000	$ 289,000	$ 99,000	34%	$ 289,410	$ 240,000	$ 49,410	-21%
Average total interest rate[1]	6.16%	5.68%	0.48%	8%	5.68%	6.08%	0.40%	-7%
Average bank borrowings	$ 211,000	$ 112,000	$ 99,000	88%	$ 111,979	$ 89,668	22,311	25%
Average bank interest rate	5.54%	3.75%	1.80%	48%	3.75%	3.42%	0.33%	10%

(1) Average total borrowings and average total interest rate includes our $175 million senior notes at 7% due June 2013 and borrowings under our revolving bank credit facility.

Interest Expense, Net of Capitalized Interest.

For 2005, the increase in gross interest expense period-over-period is due to an increase in outstanding borrowings under our revolving bank credit facility combined with an increase in average interest rates associated with our bank debt. Our average bank debt has 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 bears interest at LIBOR-based rates, the Federal Reserve raised rates by one quarter of a percent eight times during 2005. We expect to continue to see an increase in the interest rate we are paying on our bank debt if the Federal Reserve continues to increase Federal interest rates. Capitalized interest is a function of unevaluated properties and the 5% increase during 2005 is primarily a function of the increase in our average borrowing rate as the balance of unevaluated properties declined during 2005.

Table of Contents

For 2004, the increase in gross interest expense from 2003 is due to an increase in both fixed debt and bank debt offset in part by a decrease in average interest rates. Our fixed debt increased in June 2003 when we replaced our existing senior subordinated notes of $100 million at $8^{5}/_{8}$% with new senior subordinated notes of $175 million at 7%. Bank debt increased during 2004 as we utilized our revolving bank credit facility to fund not only a portion of the KeySpan Exchange in June 2004 but also our two producing property acquisitions in September and October 2004. Capitalized interest is a function of unevaluated properties and the increase for 2004 corresponds to the increase in our average unevaluated property balance throughout 2004.

Income Tax Provision.

Our provision for taxes includes both state and federal taxes. During 2005 and 2004, our state tax obligations increased as our onshore revenues increased and as we expanded our operations into several Rocky Mountain states. The 35% decrease in income taxes for 2005 from 2004 corresponds to the 35% decrease in income before taxes. During 2005, revenues were lower and expenses were higher than in 2004. Our current provision for 2005 includes $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 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.

The 34% increase in income taxes for 2004 from 2003 corresponds to the 26% increase in income before taxes from 2003 to 2004. Our current provision increased to $41.2 million during 2004 as we utilized all of our net operating loss carryforwards during 2003 and moved to a tax paying status. Prior to the third quarter of 2003, the majority of our federal income taxes were deferred. Our current provision for 2004 includes $1.4 million relating to nondeductible excess executive compensation expense of which $1.0 million was incurred in the second quarter as a result of the special bonus paid to our Chief Executive Officer in connection with the KeySpan Exchange and $0.4 million incurred in the fourth quarter as a result of the retirement of our former Senior Vice President and General Manager Offshore Division.

Liquidity

Capital Requirements

Our principal requirements for capital are to fund our exploration, development and acquisition activities and to satisfy our contractual obligations, primarily the repayment of debt and any amounts owing during the period relating to our hedging positions. Our uses of capital 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 wells; and

§ Indirect costs related to our exploration activities, including payroll and other expense attributable to our exploration professional staff.

In light of the ongoing process to sell our Gulf of Mexico assets, we are currently reviewing our capital program for 2006. To maintain 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 an opportunity is economically beneficial. We do not include property acquisition costs in our initial capital budget because the size and timing of capital requirements for acquisitions are inherently unpredictable. As the year progresses, we will continue to evaluate our capital spending. Actual levels may vary due to a variety of factors, including the timing of any sale of our Gulf of Mexico assets, drilling results, natural gas prices, economic conditions and future acquisitions.

Future Commitments

The table below provides estimates of the timing of future payments that we were obligated to make based on agreements in place at December 31, 2005. All amounts listed in the table below are categorized as liabilities on our balance sheet with the exception of lease payments for operating leases and outstanding letters of credit issued for performance obligations. At

December 31, 2005, we did not have any capital leases or long-term contracts for drilling rigs or equipment. The table includes references to our financial statements for information regarding the listed obligation. Contractual obligations relating to our revolving bank credit facility and our senior notes include only payments of principal.
In addition to the contractual obligations listed on the table below, our balance sheet at December 31, 2005, reflects accrued interest payable on our revolving bank credit facility of approximately $0.3 million which is payable over the next 90-day period. We expect to make annual interest payments of $12.3 million per year on our $175 million of 7% senior subordinated notes due June 2013. As a result of credits and amounts on deposit that were paid during 2005, we do not expect to make any cash payments for federal income taxes during 2006 and estimate less than $1.0 million for state income taxes. In connection with the pending sale of the Texas portion of our Gulf of Mexico assets and any subsequent sale of the remaining portion of our Gulf of Mexico assets, we may and may be required under our revolving bank credit facility to liquidate hedge positions allocated to offshore production. Depending on prices in effect at the time of liquidation, we could be required to make a significant payment to unwind and settle these contracts. We would expect to fund the settlement of these contracts with proceeds from the sale of any Gulf of Mexico assets and/or borrowings under our revolving bank credit facility.

		As of December 31, 2005 Payments Due by Period				
	Reference	**Total**	**1 year or less**	**2 3 years**	**4 5 years**	**after 5 years**
		(in thousands)				
Contractual Obligations:						
Revolving bank credit facility, due November 2010	Note 2	$ 422,000	$	$	$ 422,000	$
7% senior subordinated notes, due June 2013	Note 2	175,000				175,000
Derivative instruments	Note 7	417,657	352,456	65,201		
Seismic data purchase	Note 9	10,714	10,714			
Operating leases	Note 9	6,599	1,796	3,718	1,085	
Letters of credit	Note 9	300	300			
		1,032,270	365,266	69,919	423,085	175,000
Other Long-Term Obligations:						
Asset retirement obligations	Note 1	119,671	7,265	30,301	20,050	62,055
Total contractual obligations and commitments		$ 1,151,941	$ 372,531	$ 99,220	$ 443,135	$ 237,055

Capital Resources
We intend to fund our capital expenditure program, contractual commitments, including settlement of derivative contracts and future acquisitions with the proceeds from the pending sale of the Texas portion of our Gulf of Mexico

assets and/or from cash flows from our operations and borrowings under our revolving bank credit facility. We expect to use the proceeds from any sale of the remaining portion of our Gulf of Mexico assets for one or more of the following purposes: acquiring additional onshore assets, repaying indebtedness or repurchasing shares of our common stock.

At December 31, 2005, we had $177.7 million of excess borrowing capacity under our revolving bank credit facility. We expect our borrowing base to decrease upon completion of the pending sale of the Texas portion of our Gulf of Mexico assets, and to decrease further upon any sale of our remaining Gulf of Mexico assets. If a significant acquisition opportunity arises, we may also access public markets to issue additional debt and/or equity securities. Our primary sources of cash during 2005 were from funds generated from operations and bank borrowings. Cash was used primarily to fund acquisitions, exploration and development expenditures and settlements required on derivative contracts. During 2005, we made aggregate cash payments of $23.9 million and $19.3 million, respectively, for interest and taxes. The table below summarizes the sources of cash during 2005 and 2004:

	Years Ended December 31,			
	2005	**2004**	**variance**	**% change**
	(in thousands)			
Net cash provided by operating activities	$ 460,509	$ 527,141	$ (66,632)	-13%
Net cash used in investing activities	(727,003)	(509,922)	(217,081)	43%
Net cash provided by (used in) financing activities	255,896	(1,211)	257,107	+100%
Net (decrease) increase in cash	$ (10,598)	$ 16,008	$ (26,606)	-100%

At December 31, 2005, we had a working capital deficit of $214.5 million and long-term debt of $597.0 million. The working capital deficit at December 31, 2005 was due to a current liability of $352.5 million representing the fair value of our derivative instruments estimated to be payable over the next 12 months, offset in part by the associated deferred tax asset of $157.1 million. As a result of the sustained high level of natural gas prices, the fair value of our open derivative contracts payable within the next 12 months increased by $284.4 million from a liability of $68.1 million at December 31, 2004, to a liability of $352.5 million at December 31, 2005. Corresponding to the increase in the liability, the associated deferred tax asset increased by $130.5 million during this same twelve-month period of 2005. The fair value of our derivative instruments will fluctuate with commodity prices, and as commodity prices increase, our liquidity exposure tends to increase as a result of open derivative instruments. Consequently, we are more likely to have the largest unfavorable mark-to-market position in a high commodity price environment. Our working capital balance fluctuates as a result of the timing and amount of cash receipts and disbursements for operating activities and borrowings or repayments under our revolving bank 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. However, the sharp rise in prices at the end of September triggered in part by Hurricanes Katrina and Rita, resulted in a larger negative fair value than we consider normal. Prices have declined considerably and closed at $7.112 per MMBtu for March 2006 down from the $11.00 to $14.00 per MMBtu range during the fourth quarter of 2005. In addition, we may liquidate a portion of our offshore hedge position in connection with the pending sale of the Texas portion of our Gulf of Mexico assets and/or following any subsequent sale of the remaining portion of our Gulf of Mexico assets. At December 31, 2005, the fair value of derivative obligations allocated to offshore production for years 2006, 2007 and 2008 was a liability of $182.7 million ($118.0 million net of tax) which approximates the amount deferred in accumulated other comprehensive income at the end of the period.

Operating Activities. Net cash provided by operating activities decreased by $78.0 million or 14% during 2005. The decrease was primarily a result of the 31% decrease in operating income during 2005. In addition to fluctuations in operating assets and liabilities that are caused by timing of cash receipts and disbursements, commodity prices, production volume and operating expenses are the key factors driving changes in operating cash flows. For 2005, we experienced lower production volumes together with higher operating expenses.

Investing Activities. Total company capital expenditures during 2005 were $744.6 million which included $10.6 million in drilling costs accrued and unpaid at December 31, 2005. During 2005, we spent $226.1 million or 44% more than we spent during 2004. During 2005, we invested $743.3 million in natural gas and oil properties, which included $197.7 million for the acquisition of producing properties and, we spent $1.3 million for non-oil and gas property and equipment. Non-oil and gas property and equipment includes expenditures to upgrade to our information technology systems and office equipment and compares to $1.5 million spent in 2004. For 2005, we spent 32% offshore and 64% onshore with the balance of 4% on capitalized interest and general and administrative costs. We completed the drilling of a record 336 gross wells (269.8 net) of which 87% or 298 (238.4 net) were successful and 38 (31.3 net) were unsuccessful with an additional 13 wells (8.9 net) in progress at the end to the year.

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, that is defined as the sum of reserve extensions and discoveries, revisions and acquisitions. See Note 12 Supplemental Information on Natural Gas and Oil Exploration, Development and Production Activities for a detail calculation of the changes in our reserve quantities during the period.

	Years Ended December 31,				
	2005	**2004**	**2003**	**2002**	**2001**
			(in thousands)		
Natural gas and oil capital expenditures					
Producing property acquisitions	$ 197,680	$ 149,599	$ 175,420	$ 73,351	$ 69,010
Leasehold and lease acquisition costs (1)	66,113	57,741	56,076	36,458	48,068
Development	366,902	245,971	162,235	122,036	177,256
Exploration	112,634	63,646	66,259	26,536	72,056

Total natural gas and oil capital expenditures	743,329	516,957	459,990	258,381	366,390
Producing property dispositions	(1,864)	(72,712)		(5,309)	
Net natural gas and oil capital expenditures	$ 741,465	$ 444,245	$ 459,990	$ 253,072	$ 366,390
Proved reserve additions, net of revisions (MMcfe)	183,787	225,633	212,969	144,291	136,231

(1) For 2005, 2004, 2003, 2002 and 2001, leasehold costs include capitalized interest and general and administrative expenses of $25.7 million $23.2 million, $20.2 million, $21.1 million, and $24.9 million, respectively.

Financing Activities. During 2005, total long-term debt increased by a net $242 million, as we borrowed under our revolving bank credit facility in part to fund acquisitions totaling $197.7 million and in part to fund cash requirements for the settlement of derivative contracts.

Access to Capital Markets. We have the capacity to offer up to $750 million of our common stock, preferred stock, depositary shares and debt securities, or a combination of any of these securities, under effective shelf registration statements filed with the SEC in March and October 2004.

We believe that operating cash flow and our credit facility will be adequate to meet our capital and operating requirements during 2006. We continuously monitor our working capital and debt position as well as coordinate our capital expenditure program with expected cash flows and projected debt repayment schedules. In November 2005, we increased the lending commitment under our revolving bank credit facility from $450 million to $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 as of December 31, 2005 was $600 million. The borrowing base of $600 million is expected to remain in effect until the next scheduled redetermination on April 1, 2006. However, we expect our borrowing base to be reduced upon consummation of the pending sale of the Texas portion of our Gulf of Mexico Assets and likely would be further reduced upon any sale of the remaining portion of our Gulf of Mexico assets. In addition to operating cash flow and borrowings under the revolving credit facility, we believe we could finance capital expenditures with issuances of additional equity or debt securities or development with industry partners.

We plan to reinvest the net cash proceeds from the pending sale of the Texas portion of our Gulf of Mexico assets into longer-lived natural gas and oil assets onshore in North America. Our plans include structuring the reinvestment, where possible, to optimize the tax effects under the tax free exchange rules of Section 1031 of the Internal Revenue Code. However, numerous market conditions and uncertainties may not allow for the reinvestment of all of the proceeds within the prescribed time period for the most effective tax treatment. To the extent we are not able to reinvest any such proceeds, we would then expect to repay debt.

Stock Repurchase Program. In November 2005, our Board of Directors approved a plan for discretionary repurchases from time to time of up to $200 million in company stock in conjunction with the possible divesture of all of our Gulf of Mexico assets. These purchases may be in the open market or in privately negotiated transactions, and will be subject to a number of considerations, including market conditions for our shares, applicable legal requirements and contractual restrictions, available cash, competing reinvestment opportunities in the acquisition market for oil and gas assets and other factors. No repurchases have been made as of the date of this Annual Report.

Off-Balance Sheet Arrangements

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. Our sales price 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, 2005, our total debt was $597.0 million, of which approximately 29% or $175 million is fixed at an interest rate of 7%. The remaining 71% of our total debt balance at December 31, 2005, or $422 million, represents our bank debt that is tied to floating or market interest rates, prime rate or LIBOR at our election. Fluctuations in floating interest rates will cause our annual interest costs relating to our bank debt to fluctuate. During the fourth quarter of 2005, the interest rate on our outstanding bank debt averaged 6.17%. If the balance of our bank debt at December 31, 2005 were to remain constant, a 10% change in market interest rates would impact our cash flow by an estimated $650,000 per quarter.

Table of Contents

Commodity Risk

We utilize derivative commodity instruments to hedge future sales prices on a portion of our natural gas and oil production 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 and our hedging policy prescribes that at the time we enter into a contract that all hedge structures meet the requirements for hedging accounting under SFAS 133 and that each transaction is specifically identified as a hedge for Federal income tax purposes as defined in Section 1221(b)(2) of the Internal Revenue Code. While the use of certain hedging arrangements limits the downside risk of adverse price movements, it also limits increases in future revenues as a result of favorable price movements, as has been the case in recent years, especially during the last four months of 2005. The use of hedging transactions also involves the risk that the counterparties are unable to meet the financial terms of such transactions. Hedging instruments that we typically use are swaps, collars and options, which we generally place with major investment grade financial institutions that we believe are minimal credit risks. We believe that our credit risk related to our natural gas hedging instruments is no greater than the risk associated with the 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. Generally, our hedges qualify for hedge accounting under SFAS 133 and, accordingly, we carry the fair market value of our derivative instruments on the balance sheet as either an asset or liability and defer unrealized gains or losses, net of tax, 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 the hedged production occurs. If any ineffectiveness occurs, amounts are recorded directly to natural gas and oil revenues and would be included as a component of the line item natural gas and oil revenues. For us, ineffectiveness is primarily a result of changes at the end of each period in the price differentials between the price of the derivative contract, which uses a NYMEX price, and the index price for the point of sale for the cash flow that is being hedged, of which approximately 30% is the Houston Ship Channel index. If our hedges cease to qualify for hedge accounting as a result of ineffectiveness, as was the case during the fourth quarter of 2005 as a result of a loss of market correlation between the NYMEX price and the Houston Ship Channel index, we include the mark-to-market change in the fair value of open contracts in income.

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, 2005 and 2004 and provides the fair value at the end of each period:

	Year Ended December 31,	
	2005	**2004**
Change in Fair Value of Derivatives Instruments:	Before Tax (in thousands)	
Fair value of contracts at January 1	$ (75,149)	$ (36,862)
Realized loss on contracts settled	265,236	68,195
Fair value of new contracts when entered into		
(Decrease) in fair value of all open contracts	(607,745)	(106,482)
Net (decrease) increase during period	(342,509)	(38,287)
Fair value of contracts outstanding at December 31	$ (417,658)	$ (75,149)

-41-

Table of Contents

Derivatives in Place as of the Date of Our Report

The following table summarizes, on an annual basis, our natural gas hedges in place for 2006, 2007 and 2008 as of December 31, 2005. There have been no changes since the balance sheet date.

In connection with the pending sale of the Texas portion of our Gulf of Mexico assets and/or any subsequent sale of the remaining portion of our Gulf of Mexico assets, we may liquidate a portion of our 2006 hedge position associated with our offshore production, subject to the outcome of our sale process, requirements under our revolving bank credit facility, superseding operational developments and acquisition activities.

Year	Transaction Type	Daily Volume (MMBtu/day)	NYMEX Price ($/MMBtu)	Floor Price ($/MMBtu)	Ceiling Price ($/MMBtu)
2006	Swap	20,000	$ 5.87		
2006	Swap	10,000	5.94		
	Total swaps	30,000			
2006	Costless collar	10,000		$ 5.50	$ 7.20
2006	Costless collar	10,000		5.50	7.25
2006	Costless collar	40,000		5.50	7.26
2006	Costless collar	20,000		5.75	7.20
2006	Costless collar	30,000		5.80	7.00
2006	Costless collar	50,000		5.82	7.00
2006	Costless collar	30,000		6.00	7.00
2006	Costless collar	20,000		6.00	7.02
2006	Costless collar	10,000		6.00	7.05
	Total collars	220,000			
Total daily volume 2006		250,000			
2007	Costless collar	20,000		$ 5.00	$ 6.50
2007	Costless collar	10,000		5.00	6.79
Total daily volume 2007		30,000			
2008	Costless collar	20,000		$ 5.00	$ 5.72
Total daily volume 2008		20,000			

For natural gas, transactions are settled based upon the NYMEX price on the final trading day of the month. In order to determine fair market value of our derivative instruments, we obtain mark-to-market quotes from external counterparties.

With respect to any particular swap transaction, the counterparty is required to make a payment to us if 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 if 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. For option contracts, we have the option, but not the obligation, to buy contracts at the strike price up to the day before the last trading day for that NYMEX contract.

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.

Table of Contents

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 Securities Exchange Act of 1934, as amended (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, 2005. Deloitte and Touche LLP, our independent public accountants, 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 2005 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 Securities Exchange Act of 1934) occurred during the fourth quarter of our fiscal year ended December 31, 2005 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

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 Officers, Committee Assignments Committee Functions Audit Committee, Committee Functions Nominating and Governance Committee and Beneficial Ownership Reporting and Compliance Section 16(a) in our definitive proxy statement 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, 2005.

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 Summary Compensation Table, Options Granted In 2005, Aggregated Options Exercised in 2005 and Director Compensation in our definitive proxy statement that is to be filed with the SEC within 120 days of the end of our fiscal year on December 31, 2005. In addition and in accordance with Item 402(a)(8) of Regulation S-K, the information contained in our definitive proxy statement under the subheading Report of the Compensation and Management Development Committee of the Board of Directors and Performance Graph 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 Equity Compensation Plan Information and Security Ownership of Certain Beneficial Owners and Management in our definitive proxy statement that is to be filed with the SEC within 120 days of the end of our fiscal year on December 31, 2005.

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

Table of Contents

Participation in our definitive proxy statement that is to be filed with the SEC within 120 days of the end of our fiscal year on December 31, 2005.

Item 14. Principal Accounting Fees and Services

The information required by Item 14 that relates to services provided by our Independent Public Accountants 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 that is to be filed with the SEC within 120 days of the end of our fiscal year on December 31, 2005.

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:

(a) See Index of Exhibits on page F-36 for a description of the exhibits filed as a part of this report.

Table of Contents

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: March 3, 2006

Table of Contents

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)	March 3, 2006
/s/ Robert T. Ray Robert T. Ray	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 3, 2006
/s/ James F. Westmoreland James F. Westmoreland	Vice President and Chief Accounting Officer (Principal Accounting Officer)	March 3, 2006
/s/ Robert B. Catell Robert B. Catell	Director	March 3, 2006
/s/ John U. Clarke John U. Clarke	Director	March 3, 2006
/s/ David G. Elkins David G. Elkins	Director	March 3, 2006
/s/ Harold R. Logan, Jr. Harold R. Logan, Jr.	Director	March 3, 2006
/s/ Thomas A. McKeever Thomas A. McKeever	Director	March 3, 2006
/s/ Stephen W. McKessy Stephen W. McKessy	Director	March 3, 2006
/s/ Donald C. Vaughn	Director	March 3, 2006

Donald C. Vaughn

Table of Contents

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.

Deep Shelf. Structures located on the United States Outer Continental Shelf of the Gulf of Mexico at depths generally greater than 15,000 feet in areas where there has been limited or no production from deeper stratigraphic zones.

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 an 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.

Table of Contents

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.

Tangible Drilling and Development Costs. Cost of physical lease and well equipment and structures. 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.

Table of Contents

Index to Financial Statements

Table of Contents

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, 2005. 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, 2005 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
March 3, 2006

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

Table of Contents

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, 2005 and 2004, 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, 2005. 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, 2005, 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 Company as of December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, 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, 2005, 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. 143, Accounting for Asset Retirement Obligations, and SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure, on January 1, 2003.

DELOITTE & TOUCHE LLP
Houston, Texas
March 3, 2006

Table of Contents

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

	December 31, 2005	December 31, 2004
Assets:		
Cash and cash equivalents	$ 7,979	$ 18,577
Accounts receivable	146,020	103,069
Inventories	2,726	976
Deferred tax asset	145,922	24,101
Prepayments and other	19,709	9,107
Total current assets	322,356	155,830
Natural gas and oil properties, full cost method		
Unevaluated properties	107,146	122,691
Properties subject to amortization	3,556,755	2,777,097
Other property and equipment	12,971	11,740
	3,676,872	2,911,528
Less: Accumulated depreciation, depletion and amortization	1,658,532	1,363,272
	2,018,340	1,548,256
Other non-current assets	20,928	18,491
Total Assets	$ 2,361,624	$ 1,722,577
Liabilities:		
Accounts payable and accrued expenses	$ 177,159	$ 118,971
Derivative financial instruments	352,457	68,081
Asset retirement obligation	7,265	662
Total current liabilities	536,881	187,714
Long-term debt and notes	597,000	355,000
Derivative financial instruments	65,201	7,068
Deferred federal income taxes	341,302	288,069
Asset retirement obligation	112,406	91,084
Other non-current liabilities	15,696	10,722
Total Liabilities	1,668,486	939,657

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, $.01 par value, 100,000,000 shares authorized and 28,980,128 issued and outstanding at December 31, 2005 and 50,000,000 shares authorized and 28,380,207 shares issued and outstanding at December 31, 2004	289	284
Additional paid-in capital	305,077	273,002
Unearned compensation	(7,859)	(2,537)
Retained earnings	663,367	558,198
Accumulated other comprehensive income	(267,736)	(46,027)
Total Stockholders Equity	693,138	782,920
Total Liabilities and Stockholders Equity	$ 2,361,624	$ 1,722,577

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

F-4

Table of Contents

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

	For the Years Ended December 31,		
	2005	**2004**	**2003**
Revenues:			
Natural gas and oil revenues	$ 620,271	$ 649,087	$ 491,440
Other	1,272	1,352	1,312
Total revenues	621,543	650,439	492,752
Operating expenses:			
Lease operating	67,796	55,925	47,072
Severance tax	18,121	11,933	15,958
Transportation expense	11,883	11,819	10,387
Asset retirement accretion expense	5,278	4,902	3,668
Depreciation, depletion and amortization	295,351	265,148	197,530
General and administrative, net of amounts capitalized	38,378	32,899	19,542
Total operating expenses	436,807	382,626	294,157
Income from operations	184,736	267,813	198,595
Other (income) expense	142	(1,058)	(15,746)
Interest expense, net of amounts capitalized	16,535	9,455	8,342
Income before income taxes	168,059	259,416	205,999
Provision for taxes	62,890	96,592	72,187
Income before cumulative effect of change in accounting principle	$ 105,169	$ 162,824	$ 133,812
Cumulative effect of change in accounting principle			(2,772)
Net income	$ 105,169	$ 162,824	$ 131,040
Earnings per share:			
Net income per share basic			
Income before cumulative effect of change in accounting principle	$ 3.66	$ 5.50	$ 4.30
Cumulative effect of change in accounting principle			(0.09)
Net income per share basic	$ 3.66	$ 5.50	$ 4.21
Net income per share diluted			

Income before cumulative effect of change in accounting principle	$	3.62	$	5.44	$	4.29
Cumulative effect of change in accounting principle						(0.09)
Net income per share diluted	$	3.62	$	5.44	$	4.20
Weighted average shares outstanding basic		28,707		29,616		31,097
Weighted average shares outstanding diluted		29,037		29,932		31,213

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

F-5

Table of Contents

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

	Common Stock		Additional Paid-In	Unearned	Retained	Accumulated Other Comprehensive Income (Loss)	Total Shareholders Equity
	Shares	$ Value	Capital	Compensation	Earnings		
Balance January 1, 2003	**30,954,018**	**$ 310**	**$ 353,454**	**$ (107)**	**264,334**	**(25,202)**	**$ 592,789**
Common shares issued stock options	461,563	5	10,218				10,223
Common shares issued restricted stock	22,000		812	(812)			
Common shares issued public offering	3,000,000	30	79,170				79,200
Common shares repurchased from KeySpan	(3,000,000)	(30)	(79,170)				(79,200)
Amortization restricted stock				111			111
Stock compensation expense stock options			903				903
Tax benefit exercise of non-qualified stock options			1,394				1,394
Comprehensive income:							
Net income					131,040		131,040
Other comprehensive income:							
Derivative settlements reclassified to income, net of tax						43,165	43,165
Unrealized loss change in fair value of derivatives, net of tax						(44,091)	(44,091)
Total comprehensive income							130,114
Balance December 31, 2003	**31,437,581**	**$ 315**	**$ 366,781**	**$ (808)**	**$ 395,374**	**$ (26,128)**	**$ 735,534**
	873,626	9	25,586				25,595

Common shares issued stock options							
Common shares issued restricted stock	49,000		2,855	(2,855)			
Common shares issued public offering	6,820,000	68	310,659				310,727
Common shares repurchase from KeySpan	(10,800,000)	(108)	(441,471)				(441,579)
Amortization restricted stock				1,126			1,126
Stock compensation expense stock options			3,670				3,670
Tax benefit exercise of 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						44,054	44,054
Unrealized loss change in fair value of derivatives, net of tax						(63,953)	(63,953)
Total comprehensive income							142,925
Balance December 31, 2004	**28,380,207**	**$ 284**	**$ 273,002**	**$ (2,537)**	**$ 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		8,204	(8,204)			
Amortization restricted stock				2,882			2,882
Stock compensation expense stock options			4,229				4,229
Tax adjustment to 2004 benefit from non-qualified stock options			(180)				(180)
Tax benefit exercise of 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						171,342	171,342
Unrealized loss change in fair value of derivatives, net of tax						(393,051)	(393,051)
Total comprehensive (loss)							(116,540)
Balance December 31, 2005	**28,980,128**	**$ 289**	**$ 305,077**	**$ (7,859)**	**$ 663,367**	**$ (267,736)**	**$ 693,138**

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

Table of Contents

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

	Years Ended December 31,		
	2005	**2004**	**2003**
Operating Activities:			
Net income	$ 105,169	$ 162,824	$ 131,040
Adjustments to reconcile net income to net cash provided by operating activities:			
Deferred income tax expense	57,555	50,500	58,274
Depreciation, depletion and amortization	295,351	265,148	197,530
Asset retirement accretion expense	5,278	4,902	3,668
Stock compensation expense	7,111	4,796	1,014
Tax benefit (loss) non-qualified stock options	(180)	4,922	1,394
Unrealized (gain) loss on derivative instruments	(694)	1,950	1,950
Amortization of premiums paid on derivative contracts		5,287	
Debt extinguishment expense		211	1,626
Cumulative effect of change in accounting principle			2,772
Changes in operating assets and liabilities:			
Accounts receivable	(42,951)	(8,387)	(4,863)
Inventories	(1,750)	95	361
Prepayments and other	(11,714)	(3,289)	(3,622)
Other assets	(43)	(6,218)	(8,449)
Accounts payable and accrued expenses	42,403	39,693	(3,055)
Other non-current liabilities	4,974	7,276	2,329
ARO liability for assets abandoned		(2,569)	
Net cash provided by operating activities	460,509	527,141	381,969
Investing Activities:			
Investment in property and equipment	(728,882)	(523,205)	(452,959)
Dispositions and other	1,879	13,283	
Net cash used in investing activities	(727,003)	(509,922)	(452,959)
Financing Activities:			
Proceeds from long-term borrowings	831,000	420,000	414,000
Repayments of long-term borrowings	(589,000)	(367,000)	(364,000)
Debt issuance costs	(2,394)	(1,555)	(4,695)
Proceeds from issuance of common stock from exercise of stock options	16,290	25,596	10,223
Proceeds from issuance of common stock		310,727	79,200
Repurchase of common stock		(388,979)	(79,200)
Net cash (used in) provided by financing activities	255,896	(1,211)	55,528
Decrease in cash and cash equivalents	(10,598)	16,008	(15,462)
Cash and cash equivalents, beginning of year	18,577	2,569	18,031

Cash and cash equivalents, end of year	$ 7,979	$ 18,577	$ 2,569
Supplemental Information:			
Non-cash transactions:			
Investments in property and equipment accrued, not paid	$ (15,785)	$ 4,705	$ (8,863)
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	$ 23,858	$ 16,385	$ 18,403
Federal and state income taxes	19,297	41,854	14,800

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

Table of Contents

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 concentrating on growing reserves and production through 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 began exploring for natural gas and oil on behalf of KeySpan Corporation, our then parent company. KeySpan is a diversified energy provider whose principal natural gas distribution and electric generation operations are located in the Northeastern United States. In September 1996, we completed our initial public offering and sold approximately 31% of our shares to the public. Through three separate transactions, the first in February 2003 and last in November 2004, KeySpan completely divested its investment in the common stock of our company. See Note 3 Stockholders Equity - *KeySpan Exchange and Offering.*

At December 31, 2005, we had operations in five producing regions within the United States: South Texas; the Arkoma Basin of Arkansas and Oklahoma; East Texas; the Uinta and DJ Basins in the Rocky Mountains; and the Gulf of Mexico. In November 2005, we announced our intent to explore the sale of all our Gulf of Mexico assets and to shift our operating focus onshore. See Note 11 Subsequent Events *Pending Sale of Texas Gulf of Mexico Assets.*

Our total net proved reserves as of December 31, 2005 were 861 billion cubic feet equivalent or Bcfe, with onshore reserves totaling 616 Bcfe. Our reserves are fully engineered on an annual basis by independent petroleum engineers. Approximately 64% of our proved reserves at December 31, 2005, were classified as proved developed. Our daily production during 2005 averaged 313 million cubic feet of natural gas equivalent or MMcfe.

Principles of Consolidation

Our consolidated financial statements for the periods ended December 31, 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, 2003, 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. All significant inter-company balances and transactions have been eliminated.

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, our unevaluated 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

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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. We do not maintain separate 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.

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 incur production gas volume imbalances in the ordinary course of business. Net deliveries in excess of entitled amounts are recorded as liabilities, while net under deliveries are reflected as assets. Imbalances are reduced either by subsequent recoupment of over-and-under deliveries or by cash settlement, as required by applicable contracts. Production imbalances are marked-to-market at the end of each month at the lowest of (i) the price in effect at the time of production; (ii) the current market price; or (iii) the contract price, if a contract is in hand.

At December 31, 2005, we had production imbalances representing assets of $4.9 million and liabilities of $7.2 million. The primary sources of our production imbalances relate to Eugene Island 331, acquired in October 2003 from Transworld Exploration and Production Inc., and to various Arkoma wells. At December 31, 2004, we had production imbalances representing assets of $3.3 million and liabilities of $4.0 million. At December 31, 2004, the primary sources of our production imbalances related to Gulf of Mexico properties acquired in October 2004 from Orca Energy, L.P. and in October 2003 from Transworld Exploration and Production Inc. See Note 10 Acquisitions and Dispositions. Production imbalances are included in the line items other non-current assets and other non-current liabilities on the balance sheet.

Table of Contents

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 primarily of employee stock options and restricted common stock.

	Years Ended December 31,		
	2005	**2004**	**2003**
	(in thousand, except per share data)		
Numerator:			
Income before cumulative effect of change in accounting principle	$ 105,169	$ 162,824	$ 133,812
Cumulative effect of change in accounting principle			(2,772)
Net income	$ 105,169	$ 162,824	$ 131,040
Denominator:			
Weighted average shares outstanding	28,707	29,616	31,097
Add dilutive securities: Stock options and restricted stock	330	316	116
Total weighted average shares outstanding and dilutive securities	29,037	29,932	31,213
Earnings per share basic:			
Income before cumulative effect of change in accounting principle	$ 3.66	$ 5.50	$ 4.30
Cumulative effect of change in accounting principle			(0.09)
Net income per share basic	$ 3.66	$ 5.50	$ 4.21
Earnings per share diluted:			
Income before cumulative effect of change in accounting principle	$ 3.62	$ 5.44	$ 4.29
Cumulative effect of change in accounting principle			(0.09)
Net income per share diluted	$ 3.62	$ 5.44	$ 4.20

For the years ended December 31, 2005, 2004 and 2003, the calculation of shares outstanding for diluted net income per share does not include the effect of outstanding stock options to purchase 459,215, 755,922, and 1,865,313 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 includes net income and certain items recorded directly to stockholders equity and classified as other comprehensive income. The table below summarizes comprehensive income and provides the components of the change in accumulated other comprehensive income for the twelve-month periods ended December 31, 2005, 2004 and 2003, respectively.

	For the Year Ended December 31,		
	2005	**2004**	**2003**
		(in thousands)	
Net income	$ 105,169	$ 162,824	$ 131,040
Other comprehensive income (loss)			
Derivative instruments settled and reclassified, net of tax	171,342	44,054	43,165
Change in unrealized (loss) fair value of open contracts, net of tax	(393,051)	(63,953)	(44,091)
Total other comprehensive (loss)	(221,709)	(19,899)	(926)
Comprehensive income (loss)	$ (116,540)	$ 142,925	$ 130,114

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 incurred in the acquisition, exploration and development of natural gas and oil reserves are capitalized into a full cost pool. Capitalized costs include costs of all unproved properties, internal costs directly related to our natural gas and oil activities and capitalized interest. We amortize these costs using a unit-of-production method. We compute the provision for depreciation, depletion and amortization quarterly by multiplying production for the quarter by a depletion rate. The depletion rate is determined by dividing our total unamortized cost base by net equivalent proved reserves at the beginning of the quarter. Our total unamortized cost base is the sum of our:

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

§ estimates for future development costs (excluding asset retirement obligations); less,

§ unevaluated properties and their related costs; less,

§ estimates for salvage.

Costs associated with unevaluated properties are excluded from the amortization 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 of natural gas and oil properties are accounted for as adjustments 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.

Under full cost accounting rules, total capitalized costs are limited to a ceiling equal to the present value of future net revenues, discounted at 10% per annum, plus the lower of cost or fair value of unproved properties less income tax effects (the ceiling limitation). We perform a quarterly ceiling test to evaluate whether the net book value of our full cost pool exceeds the ceiling limitation. If capitalized costs (net of accumulated depreciation, depletion and amortization) less related deferred taxes are greater than the discounted future net revenues or 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 and adjusted for basis or location differential, held constant over the life of the reserves. We use derivative financial instruments that qualify for cash flow hedge accounting under SFAS 133, Accounting for Derivative Instruments and Hedging Activities, to hedge against the volatility of natural gas prices, and in accordance with SEC guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation. 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, 2005, 2004 and 2003, we estimated, using wellhead prices of $8.21 per Mcfe, $5.75 per Mcfe and $5.74 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 that the ceiling limitation by $329.9 million (after tax) for 2005 and $399.3 million (after tax) for 2004 and $440.7 million (after tax) for 2003. No writedown was required.

Unevaluated Properties. The costs associated with unevaluated properties and properties under development 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 interest costs capitalized 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 wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. Costs of dry holes are transferred to the amortization base immediately upon determination that the well is unsuccessful. All items classified as unevaluated property are assessed on a quarterly basis for possible impairment or reduction in value. 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

Table of Contents

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

million were incurred in 2004, $30.5 million were incurred in 2003 and $20.4 million were incurred prior to 2002. Of the $122.7 million of unevaluated property costs at December 31, 2004 that have been excluded from the amortization base, $41.1 million were incurred during 2004, $48.2 million were incurred in 2003, $16.5 million were incurred in 2002 and $16.9 million were incurred prior to 2001. We estimate these costs will be evaluated 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 is 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 the purposes of calculating depreciation, depletion and amortization expense. For the 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, 2005 and 2004. The ARO liability in the table below includes amounts classified as both current and long-term at December 31st.

	Years Ended December 31,	
	2005	2004
	(in thousands)	
ARO liability at January 1,	$ 91,746	$ 92,357
Accretion expense	5,278	4,902
Liabilities incurred from drilling	7,520	4,487
Liabilities incurred assets acquired	5,783	19,638
Liabilities settled assets sold	(32)	(12,714)
Liabilities settled assets abandoned	(971)	(4,915)
Changes in estimates	10,347	(12,009)
ARO liability at December 31,	$ 119,671	$ 91,746

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 between two to five years.

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.

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.

Table of Contents

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

General and Administrative Costs and Expenses

Under the full cost method of accounting, a portion of our general and administrative expenses that are directly identified with our acquisition, exploration and development activities are capitalized as part of our full cost pool. These capitalized costs include salaries, employee benefits, costs of consulting services and other specifically identifiable costs and do not include costs related to production operations, general corporate overhead or similar activities. We capitalized general and administrative costs directly related to our acquisition, exploration and development activities, during 2005, 2004 and 2003 of $16.9 million, $14.8 million and $12.9 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 $2.1 million, $2.2 million and $1.6 million for the years ended December 31, 2005, 2004 and 2003, 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 related to our unevaluated natural gas and oil properties. For the years ended December 31, 2005, 2004 and 2003, we capitalized interest costs of $8.8 million, $8.4 million and $7.3 million, respectively.

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.

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 futures and swap 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.

Derivative Instruments and Hedging Activities

Our hedging policy does not permit us to hold derivative instruments for trading purposes. Our hedging policy prescribes that upon entering into all derivative contracts, all hedge structures meet the requirements for hedging accounting under SFAS 133 and all hedge transactions are specifically identified as hedges for federal income tax purposes as defined in Section 1221(b)(2) of the Internal Revenue Code. Historically, we have hedged between 70% and 80% of our estimated future production. Our hedging policy allows us the flexibility to implement a wide variety of hedging strategies,

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

including swaps, collars and options. We generally execute contracts with significant, creditworthy financial institutions and, to a lesser extent, other counterparties. 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 New York Mercantile Exchange (NYMEX) prices, as opposed to the index price where the gas is actually sold, our hedging strategy will not fully protect our cash flows when, as in recent quarters, the price differential increases between the NYMEX price and index price for the point of sale.

Generally, our derivative instruments qualify for hedge accounting. Consequently, we carry the fair market value of our derivative instruments on the balance sheet as either an asset or liability and defer unrealized gains or losses 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 the hedged production occurs. If any ineffectiveness occurs, amounts are recorded directly to the income statement and would be included as a component of the line item natural gas and oil revenues. For us, ineffectiveness is primarily a result of changes at the end of the current period in the price differentials between the index price of the derivative contract, which uses a NYMEX price, and the index price for the point of sale for the cash flow that is being hedged, the majority of which is the Houston Ship Channel index. For the years ended December 31, 2005, 2004 and 2003, we recorded losses due to the measured ineffectiveness of open contracts of $46.0 million ($29.7 million net of tax), $1.9 million ($1.3 million net of tax) and $1.9 million ($1.3 million net of tax), respectively.

If our hedge contracts cease to qualify for hedge accounting as a result of ineffectiveness, we recognize the mark-to-market change in the fair value of the open contracts in income. During the fourth quarter of 2004, our hedged production allocated to the Houston Ship Channel index failed to qualify for hedging accounting due to a loss of correlation which the NYMEX price caused primarily by the impact of Hurricanes Katrina and Rita. Accordingly, we recognized a gain of $26.1 million ($16.9 million net of tax). At December 31, 2005, our open derivative contracts extended through each of the twelve months of 2006, 2007 and 2008. In addition, during the fourth quarter of 2005 as a result of a production shortfall caused by hurricane related curtailments, we deferred a loss of $20.6 million in accumulation other comprehensive income, which we expect to realize when the related gas is produced.

Based on market prices at December 31, 2005, we recorded an unrealized loss in accumulated other comprehensive income of $267.7 million, net of tax, representing the fair value of our open derivative contracts. Any loss will be realized in future earnings at the time of the related sales of natural gas production applicable to specific hedges. If prices in effect at December 31, 2005 were to remain unchanged, over the next 12-month period, we would expect to reclassify from accumulated other comprehensive income to earnings a loss of $198.9 million, net of tax, relating to our open derivative contracts. However, these amounts could vary materially as a result of changes in market conditions.

We enter into a substantial portion of our hedge contracts with counterparties who are participant banks in our revolving 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 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, 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 the SFAS 148. As a result, we recorded as compensation expense the fair value of all stock options issued subsequent to January 1, 2003. No expense for stock options has been recorded for grants made in years prior to January 1, 2003. Prior to 2003, 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. Accordingly, compensation cost for stock options was measured as the excess, if any, of the fair value of common stock at the date of the grant over the amount the employee must pay to acquire the common stock. If

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

the exercise price of a stock option was equal to the fair market value at the time of grant, no compensation expense was incurred.

If we had accounted for all stock options using the fair value method as recommended in SFAS 123, stock 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, 2004 and 2003:

	Years Ended December 31,		
	2005	2004	2003
	(in thousands, except per share data)		
Net income as reported	$ 105,169	$ 162,824	$ 131,040
Add: Stock-based compensation expense included in net income, net of tax	3,292	2,581	551
Less: Stock-based compensation expense determined using fair value method, net of tax	4,679	4,694	4,427
Net income pro forma	$ 103,782	$ 160,711	$ 127,164
Net income per share basic as reported	$ 3.66	$ 5.50	$ 4.21
Net income per share diluted as reported	3.62	5.44	4.20
Net income per share basic pro forma	$ 3.62	$ 5.43	$ 4.09
Net income per share diluted pro forma	3.57	5.37	4.07

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 fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions:

	Years Ended December 31,		
	2005	2004	2003
Risk-free interest rate	4.1%	3.7%	4.0%
Expected life in years	5	5	5
Expected stock volatility	42.7%	37.2%	42.7%
Expected dividends	0.0%	0.0%	0.0%

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 daily rates for either five-year or three-year United States treasury bills with constant maturity that correspond to the option s vesting period. The expected life is based on historical exercise activity over the previous nine-year period. The expected volatility is based on historical volatility and measured using the average closing price of our stock over a 60-month period. We believe historical volatility is the most accurate measure of future volatility of our common stock. The weighted average fair value of options at their grant date during 2005, 2004 and 2003 were $16.62, $21.36 and $14.61, respectively.

New Accounting Pronouncements

On December 16, 2004, the FASB issued Statement 123 (revised 2004), Share-Based Payment (SFAS 123(R)), which requires the measurement and recognition of compensation expense for all stock-based compensation payments and the current accounting under SFAS 123, Accounting for Stock-Based Compensation, and supersedes Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees. For us, SFAS 123(R) is effective

for our first fiscal year beginning after June 15, 2005, or January 1, 2006.
On January 1, 2003, we adopted the fair value expense recognition provisions of SFAS 123 as amended by SFAS 148, Accounting for Stock-Based Compensation Transition and Disclosure using the prospective method as defined by the SFAS 148. As a result, we have recognized compensation expense for all stock options granted subsequent to January 1, 2003, with no expense recognized for grants made prior to 2003. With the adoption of SFAS 123(R), we will recognize compensation expense over the remaining service period for the unvested portion of all options granted during 2001 and 2002. All options granted prior to 2001 are fully vested. We adopted SFAS 123(R) on January 1, 2006, using the

Table of Contents

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

modified version of the prospective application. We plan to continue using the Black-Scholes option pricing model to estimate the fair value of our options on the date of grant. We do not believe the adoption of SFAS 123(R) will have a material impact on our financial statements.

In March 2005, the SEC released Staff Accounting Bulletin (SAB) 107 providing additional guidance in applying the provisions of SFAS 123(R), Share-Based Payment. SAB 107 should be applied when adopting SFAS 123(R) and addresses a wide range of issues, focusing on valuation methodologies and the selection of assumptions. In addition, SAB 107 addresses the interaction of SFAS 123(R) with existing SEC guidance.

NOTE 2 Long-Term Debt and Notes

	Years Ended December 31, 2005	2004
	(in thousands)	
Senior Debt:		
Revolving bank credit facility, due November 30, 2010	$ 422,000	$ 180,000
Subordinated Debt:		
7% senior subordinated notes, due June 15, 2013	175,000	175,000
Total long-term debt and notes	$ 597,000	$ 355,000

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, 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, 2004, the quoted market value of our $175 million of 7% senior subordinated notes was 101% of the $175 million carrying value or $177 million. At December 31, 2005, principal payments due over the next five-year period and thereafter are as follows.

	2006	2007	2008	2009	2010	After 2011
				(in thousands)		
Revolving bank credit facility	$	$	$	$	$ 422,000	$
7% senior Subordinated Notes						175,000
Total maturities	$	$	$	$	$ 422,000	$ 175,000

Revolving Bank Credit Facility

We maintain a revolving bank 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 credit facility was amended and restated on November 30, 2005, primarily to increase the size of the facility. As amended, the facility provides us with a commitment of $750 million, which may be increased at our request and with prior approval from Wachovia to a maximum of $850 million. Amounts available for borrowing under the credit facility are limited to a borrowing base, which as of December 31, 2005 was $600 million. The borrowing base of $600 million is expected to remain in effect until the next scheduled redetermination on April 1, 2006. However, we expect our borrowing base to be reduced upon consummation of the pending sale of the Texas portion of our Gulf of Mexico assets and likely would be further reduced upon any subsequent sale of the remaining portion of our Gulf of Mexico assets (see Note 11 Subsequent

Events *Pending Sale of Texas Gulf of Mexico Assets*). Up to $60 million of the borrowing base is available for the issuance of letters of credit. Outstanding borrowings under the revolving credit facility are secured by our onshore 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, 2005, we had $422 million in outstanding borrowings under the credit facility and $0.3 million in outstanding letter of credit obligations.

Interest is payable on borrowings under our revolving bank 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

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

§ 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 bank credit facility contains customary negative 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, to purchase or redeem our stock and to 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

§ not hedge more than 85% of our production during any calendar year.

At December 31, 2005, and December 31, 2004, 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, beginning December 15, 2003. 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. In addition, at any time prior to June 15, 2006, we may redeem up to a maximum of 35% of the aggregate principal amount with the net proceeds of one or more equity offerings at a price equal to 107% of the principal amount, plus accrued and unpaid interest and liquidated damages, if any. The notes are general unsecured obligations and rank subordinate in right of payment to all existing and future senior debt, including the revolving bank credit facility, and will rank senior or equal in right of payment to all 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.

In addition, upon the occurrence of a change of control (as defined in the indenture), we 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.

Table of Contents

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 3 Stockholders Equity

Stock Repurchase Program

In November 2005, our Board of Directors approved a plan for discretionary repurchases from time to time of up to $200 million in company stock in conjunction with the possible divesture of all of our Gulf of Mexico assets. These purchases may be in the open market or in privately negotiated transactions, and will be subject to a number of considerations, including market conditions for our shares, applicable legal requirements, contractual limitations, available cash, competing reinvestment opportunities in the acquisition market for oil and gas assets and other factors. No repurchases were made during 2005.

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.

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 described 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.

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.

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 and Option 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 $1.4 million, $1.2 million and $1.3 million, respectively, for the years ended December 31, 2005, 2004 and 2003.

Deferred Compensation Plan

We maintain a deferred compensation plan for the benefit of our employees. The 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 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 2005, 2004 and 2003, we made matching contributions totaling $1.2 million, $0.7 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, 2005 and 2004, the fair market value of the assets held in the trust was $8.5 million and $6.7 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 Deferred Liabilities. On January 31, 2006, the plan was amended in order to comply with provisions added to the Internal Revenue Code by the American Jobs Creation Act of 2004.

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 amount of this monthly 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), 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.

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 $5.0 million, $6.2 million and $4.8 million in 2005, 2004 and 2003.

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 will receive a bonus equal to one year s base salary, with 50% payable in cash and 50% payable in restricted stock of the company. Participants will earn their bonus over a 36 month period, with the first payment of cash and stock to be made 18 months after the first anniversary of the plan or January 26, 2007. The final payment will be made 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, 2005, we had 52,501 restricted units outstanding under the plan. For the year ended December 31, 2005, we incurred costs of $1.3 million 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.

Deferred Compensation Plan for Non-Employee Directors

We maintain a deferred compensation plan for non-employee, non-affiliated directors. The plan in 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. The plan was amended in 2005 to comply with the American Jobs Creation Act of 2004. Deferred fees under the plan totaled $0.9 million for each of the years ended December 31, 2005 and 2004.

Stock and Option Plans

We have four stock option 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, amended and approved by the 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 the stockholders in May 2002 and amended by our Board in October

Table of Contents

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2003; and (iv) the 2004 Long-Term Incentive Plan, approved by the stockholders in June 2004 and amended and restated in January 2006. All our employees, directors, consultants and advisors are eligible to participate in our Stock Plans, with the exception of executive officers who are not eligible to participate in the 1999 plan. 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, with the exception of options granted to directors whose options vest immediately upon grant. In general, stock options become fully vested upon the occurrence of a change of control, unless an award agreement provides otherwise. All grants are made at the closing price of our common stock as reported on the NYSE on the date of grant. The 1996, 2002 and 2004 plans allow for the grant of both incentive stock options and non-qualified stock options. After the amendment and restatement of the 2004 plan in January 2006, non-employee directors are no longer eligible to receive grants of non-qualified stock options.

Common stock issued through the exercise of non-qualified stock options will result in a tax deduction for us which is equal to the taxable gain recognized by the optionee. Generally, we will 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. The exercise of non-qualified stock options during 2005, 2004 and 2003 resulted in a tax benefit to us of approximately $ 3.5 million, $4.9 million and $1.4 million, respectively. For 2005, the tax benefit of $3.5 million was not able to be utilized for the current tax period due to a tax net operating loss for the year ended December 31, 2005.

In addition to stock options, the 2002 plan and 2004 plan allow for the grant of restricted stock. Restricted stock carries voting and dividend rights; however, the sale or transfer of the shares is restricted. During 2005, 2004 and 2003, restricted stock was granted and issued to certain executive officers, non-employee directors and affiliated directors as a component of each recipient s annual compensation. 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, a change of control (as defined by the plan), 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.

On January 1, 2003, we adopted the fair value expense recognition provisions of SFAS 123, as amended by SFAS 148, Accounting for Stock Based Compensation Transition and Disclosure using the Prospective Method as defined by the SFAS 148. As a result, we record as compensation expense the fair value of all stock options issued subsequent to January 1, 2003. For the years ended December 31, 2005, 2004 and 2003, we did not incur compensation expense for stock options granted prior to January 1, 2003.

The table below provides a detail of stock compensation expenses incurred during the years ended December 31, 2005, 2004 and 2003. 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.

	December 31,		
	2005	**2004**	**2003**
	(in thousands)		
Options	$ 4,229	$ 3,670	$ 903
Restricted stock and units[(1)]	2,882	1,126	111
Stock compensation expense, gross	7,111	4,796	1,014
Amounts capitalized	(2,015)	(800)	(166)
Stock compensation expense, net of amounts capitalized	$ 5,096	$ 3,996	$ 848

(1) Includes $21,000 and $85,000, respectively, during 2004 and 2003 for the amortization of 10,000 shares of restricted stock granted to our Chief Executive Officer upon his employment with our company in April 2001. These shares fully vested in April 2004 and were not made pursuant to one of our Plans.

The following table summarizes all of our Stock Plans as of December 31, 2005. 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.

Table of Contents

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	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	646,680	1,194,000	806,606	2,132,758	4,780,044
Forfeitures	(33,772)	(85,720)	(43,665)	(26,600)	(189,757)
Cancellations		322,045	37,059	18,300	377,404
Total options	612,908	1,478,000	800,000	3,033,912	5,924,820
Restricted stock and units:(1)					
Grants	195,423	22,000			217,423
Forfeitures	(4,317)				(4,317)
Total restricted stock and units (2)	191,106	22,000			213,106
Options and restricted stock available for grant	695,986				695,986
Total exercised and issued	163,558	540,370	547,329	2,755,632	4,006,889

(1) Average grant price for restricted stock was $57.47, $58.28 and $36.94, respectively, during years ended December 31, 2005, 2004 and 2003.

(2) Includes 52,501 units granted in 2005 pursuant to the July 2005 Retention Bonus Plan at an average of $58.76 per share.

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

	Years Ended December 31,					
	2005		2004		2003	
	Shares	Price(1)	Shares	Price (1)	Shares	Price (1)
Options outstanding January 1	1,957,598	$35.05	2,535,159	$30.23	2,421,166	$27.50
Granted	345,230	55.37	342,950	55.98	606,725	34.86
Exercised	(510,316)	31.92	(873,626)	29.30	(461,563)	22.15
Forfeited	(95,902)	40.14	(46,885)	34.49	(31,169)	27.73
Options outstanding December 31	1,696,610	$39.85	1,957,598	$35.05	2,535,159	$30.23
Options exercisable December 31	615,523	$32.83	555,546	$29.80	838,568	$28.28

Options available for grant December 31	695,986	1,152,975	309,889

(1) Weighted average price. For all grants, the grant price equal to closing market price on the NYSE on date of grant.

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, 2005

		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**
$ 15.50	$ 17.25	14,400	1996	1 years	$ 15.60	14,400	$ 15.50	
$ 13.13	$ 25.00	15,900	1997	2 years	20.73	15,900	20.73	
$ 15.75	$ 23.38	6,920	1998	3 years	18.86	6,920	18.86	
$ 16.94	$ 21.00	27,430	1999	4 years	19.62	27,430	19.62	
$ 18.00	$ 26.19	29,500	2000	5 years	23.72	29,500	23.72	
$ 22.50	$ 37.38	315,482	2001	6 years	29.38	205,247	29.56	110,235
$ 27.49	$ 33.75	318,760	2002	7 years	30.15	120,800	30.14	197,960
$ 26.18	$ 37.42	339,785	2003	8 years	34.75	96,320	35.07	243,465
$ 36.56	$ 60.45	294,678	2004	9 years	56.08	74,006	57.93	220,672
$ 46.25	$ 67.08	333,755	2005	10 years	55.37	25,000	36.55	308,755
		1,696,610			$ 39.85	615,523	$ 32.83	1,081,087

F-22

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 5 Income Taxes

The components of the federal income tax provision are:

	Years Ended December 31,		
	2005	2004	2003
		(in thousands)	
Current	$ 5,335	$ 46,092	$ 13,913
Deferred	57,555	50,500	58,274
Total	$ 62,890	$ 96,592	$ 72,187

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. We plan to carry back this net operating loss to years 2004 and 2003 for tax refunds. 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 and 2003, 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,		
	2005	2004	2003
		(in thousands)	
Income before income taxes	$ 168,059	$ 259,416	$ 205,999
Statutory rate	35%	35%	35%
Income tax expense computed at statutory rate	58,821	90,796	72,100
Reconciling items:			
State income taxes and other, net of federal tax benefit	672	4,358	
Permanent differences	40	45	29
Other adjustments [1]	1,852		58
Non-deductible compensation expense	1,505	1,393	
Tax provision	$ 62,890	$ 96,592	$ 72,187

[1] For 2005, includes an adjustment relating to 2004 estimates for federal and state taxes. For 2003, comprised of excess deductions for Section 29 tax credits taken in 2002.

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 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.

For 2004, the change in the balance of our deferred tax liability was comprised of deferred tax expense of $50.5 million, a tax benefit of $11.1 million due to the change in the fair value of our open derivative contracts that has been deferred in accumulated other comprehensive income and a reduction of $7.4 million to our deferred tax liabilities related to oil and gas property and equipment associated with the Appalachian Basin assets divested as part of the KeySpan Exchange in June 2004.

Table of Contents

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Years Ended December 31, 2005	2004
	(in thousands)	
Deferred tax assets:		
Derivative instruments	$ 146,716	$ 25,222
Ineffectiveness derivative instruments	1,135	1,381
Net operating loss	11,101	
Alternative minimum tax credit carryforwards	8,728	
Deferred compensation	5,728	4,327
Total deferred tax assets	173,408	30,930
Deferred tax liabilities:		
Oil and gas property and equipment	368,788	294,898
Total deferred tax liability	$ 195,380	$ 263,968
Reflected in the accompanying Balance Sheet as:		
Current deferred income tax asset	$ (145,922)	$ (24,101)
Non-current deferred income tax liability	341,302	288,069
	$ 195,380	$ 263,968

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. Employment 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 employment agreement. Executive officers receive annual salary and bonus payments pursuant to their employment agreements and are eligible to participate in our stock compensation, deferred compensation and supplemental executive pension plans.

If we terminate 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), we are obligated to pay the executive a lump-sum severance payment equal to 2.99 times his then current annual rate of total compensation, and to continue certain medical and insurance benefits for a specified time period. The agreements further provide 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, we will make each of the executives whole on a net after-tax basis.

We may terminate any employment agreement for cause without financial obligation (other than payment of any accrued obligations). Each executive may terminate his agreement at any time for any reason upon at least 30 days prior written notice. 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.

Employment Agreement with Robert T. Ray, Chief Financial Officer

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. The terms of Mr. Ray s employment agreement are consistent with the general terms described above. Further, under Mr. Ray s agreement, he will initially receive a base salary of $315,000 (subject to review each year by our Compensation Committee) and will be entitled to an annual incentive bonus equal to 55% of his base salary. Payment of the bonus is based on achievement of certain performance goals established each year by our Compensation Committee. In addition, Mr. Ray received a signing bonus in the amount of $85,000, along with 20,000 stock options and 7,500 restricted shares our common stock. Mr. Ray is

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

eligible to participate in our stock compensation and deferred compensation plans, as well as our Supplemental Executive Retirement Plan. The agreement provides for an automobile allowance of $700 per month and reimbursement of certain business expenses and requires us to provide certain disability and life insurance. If we terminate Mr. Ray without cause, or if he terminates his employment with us for good reason, we are obligated to pay him a lump sum severance payment, based on his initial compensation, equal to approximately $1.5 million.

Amendments to Employment Agreements

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. 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

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 will continue certain welfare benefits. 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 2005, 2004, and 2003 we purchased services and supplies from NATCO of $1.3 million, $0.9 million and $1.1 million, respectively. Mr. Clarke meets all requirements of the New York Stock Exchange to be considered an independent director of our company.

Table of Contents

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

NOTE 7 Derivative Instruments

As of December 31, 2005, we had entered into commodity price hedging contracts with respect to approximately 75% of our forecasted natural gas production for 2006 and less than 10% for 2007 and 2008 as listed in the tables 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 have deferred a net $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 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.

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, 2005, we did not have any outstanding letters of credit issued relating to derivative contracts.

Natural Gas	**Fixed Price Swaps**		**Collars**			
	Daily Volume	**NYMEX Contract**	**Daily Volume**	**NYMEX Contract Price**		
Period	**(MMBtu)**	**Price**	**(MMBtu)**	**Floor**	**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)

At December 31, 2004, we had entered into commodity price hedging contracts with respect to our natural gas production for 2005 through 2008 as listed in the tables below. The total estimated fair value of our natural gas and oil derivative instruments at December 31, 2004 was a liability of $75.1 million, of which we have deferred a net $46.0 million in accumulated other comprehensive income and recognized $1.9 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.

As of December 31, 2004, we did not have any outstanding letters of credit issued relating to derivative contracts.

Natural Gas	**Fixed Price Swaps**		**Collars**	
	Daily Volume	**NYMEX Contract**	**Daily Volume**	**NYMEX Contract Price**

Period		**(MMBtu)**	**Price**	**(MMBtu)**	**Floor**	**Ceiling**	**Fair Value**
							(thousands)
January	December 2005	80,000	$5.304	180,000	$4.833	$6.434	$(68,081)
January	December 2006	30,000	5.893	60,000	5.500	7.248	(3,889)
January	December 2007			30,000	5.000	6.597	(1,662)
January	December 2008			20,000	5.000	5.720	(1,517)
							$(75,149)

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2005, 2004 and 2003 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.

	For the Year Ended December 31,		
Major Purchaser	**2005**	**2004**	**2003**
ConocoPhillips	11.9%	11.9%	18.4%
Anadarko Petroleum Corporation	10.1%	9.08%	11.7%
KinderMorgan	2.7%	10.1%	11.4%

NOTE 9 Commitments and Contingencies

Legal Proceedings

We are involved from time to time in various claims and lawsuits incidental to our business. In the opinion of management, the ultimate liability, if any, of these claims and lawsuits will not have a material adverse effect on our financial position or results of operations.

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, 2005, 2004 and 2003, we recognized as other income refunds of prior period severance tax payments of $2.7 million, $1.2 million and $21.6 million, respectively. At December 31, 2005, and 2004, our current receivables include $0.7 million and $1.3 million, respectively, in gross refunds of which we estimate, approximately 70%, or $0.5 million and $9.0 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.

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 2006 through 2010. Rental expense related to these leases was $1.9 million, $1.6 million and $1.3 million, respectively, for the years ended December 31, 2005, 2004 and 2003. At December 31, 2005, our total commitment under these non-cancelable operating leases was $6.6 million. Minimum rental commitments under the terms of our operating leases are as follows (in thousands):

Table of Contents

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years Ended December 31,	Minimum Payments
2006	$ 1,796
2007	1,855
2008	1,863
2009	1,083
2010	2
Thereafter	
Total	$ 6,599

Purchase Obligations
We have committed to acquire additional offshore seismic data under two license agreements for a total of $10.7 million, of which $7.7 million is payable in January 2006 and $3.0 million is payable by March 31, 2006.
Letters of Credit
We had $0.3 million and $0.4 million, respectively, in letters of credit outstanding at December 31, 2005 and 2004.
NOTE 10 Acquisitions and Dispositions (Reserve quantities, wells, acreage and working interests included below are unaudited.)
Acquisition of South Texas Properties
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 revolving 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%.
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 the 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 revolving 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 represents 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 revolving bank credit facility. The 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.

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 revolving 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 revolving 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 revolving bank credit facility.

EnerVest Acquisition

On December 31, 2003, we completed the purchase of certain producing natural gas and oil properties and associated gathering pipelines and equipment located in the Appalachian Basin of West Virginia and Pennsylvania from EnerVest East Limited Partnership. The properties acquired were adjacent to our existing producing properties in West Virginia. The $28 million purchase price was reduced by $0.2 million for various customary closing items, including revenues

Table of Contents

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

received by and expenditures made by the seller related to the properties acquired for the period between the effective date of the transaction, December 1, 2003, and the closing date, December 31, 2003. The net purchase price of $27.9 million was paid in cash and financed by borrowings under our revolving bank credit facility. The properties purchased cover approximately 146,000 gross (83,950 net) acres. The properties acquired include working interests in approximately 774 producing wells Our average working interest is 74% and we will we operate approximately 85% of the wells acquired. In addition, the interests acquired include approximately 300 wells in which we will have an overriding royalty interest. Total proved reserves associated with the interests acquired were 23.4 Bcfe, as of the December 31, 2003.

Transworld Exploration and Production Inc. Acquisition

On October 15, 2003, we completed the acquisition of Transworld Exploration and Production Inc. s shallow-water Gulf of Mexico natural gas and oil producing properties and undeveloped acreage. At closing, the $155 million purchase price was reduced by $7.5 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, July 1, 2003, and the closing date, October 15, 2003. The net purchase price of $147.5 million was paid in cash and financed in part by cash on hand and in part by borrowings under our revolving bank credit facility. The properties are located primarily in the central Gulf of Mexico in less than 320 feet of water and include 21 blocks covering 86,237 gross (64,394 net) acres. As of the October 15, 2003 closing date, proved reserves were an estimated 88.5 Bcfe, of which 75% is natural gas. We operate properties representing 97% of the proved reserves with an average working interest of 65%.

NOTE 11 Subsequent Events

Pending Sale of Texas Gulf of Mexico Assets

On February 28, 2006, we entered into a definitive purchase and sale agreement with certain partnerships affiliated with Merit Energy Company whereby these entities will acquire the Texas portion of our Gulf of Mexico assets for a purchase price of $220 million in cash, subject to adjustment and customary closing requirements. The sale of these assets will be effective January 1, 2006, and the transaction is expected to close on March 31, 2006. The Texas portion of our Gulf of Mexico assets accounted for approximately 18% of our 2005 production and represented 58.5 Bcfe, or 7% of our total proved reserves, at December 31, 2005.

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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,		
	2005	2004	2003
		(in thousands)	
Unevaluated properties, not subject to amortization	$ 107,146	$ 122,691	$ 134,491
Properties subject to amortization	3,462,907	2,705,897	2,252,852
Asset retirement obligations (1)	93,848	71,200	71,159
Capitalized costs	3,663,901	2,899,788	2,458,502
Accumulated depreciation, depletion and amortization	(1,649,674)	(1,355,857)	(1,092,073)
Net capitalized costs	$ 2,014,277	$ 1,543,931	$ 1,366,429

Additions to Unevaluated Properties

The following table provides a summary of unevaluated costs not being amortized as of December 31, 2005, 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 within four years.

	Costs incurred by Year as of December 31, 2005				
	Total	2005	2004	2003	2002 and Prior
			(in thousands)		
Property acquisition costs	$ 82,457	$ 28,120	$ 13,104	$ 28,723	$ 12,510
Exploration and development	13,599	4,429	1,168	119	7,883
Capitalized interest	11,090	5,366	4,052	1,672	
Total	$ 107,146	$ 37,915	$ 18,324	$ 30,514	$ 20,393

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, 2005, 2004 and 2003 include interest expense and general and administrative costs related to acquisition, exploration and development of natural gas and oil properties of $25.6 million, $23.2 million and $20.2 million, respectively. During the years ended December 2005, 2004 and 2003, we spent $128.9 million, $56.7 million and $46.0 million, respectively, to develop our proved undeveloped reserves.

	As of December 31,		
	2005	2004	2003
		(in thousands)	
Property acquisition and leasehold costs			
Unevaluated	$ 31,009	$ 28,059	$ 61,224

Proved	232,784	179,281	170,272
Exploration costs	112,634	63,646	66,259
Development costs	366,902	245,971	162,235
	743,329	516,957	459,990
Asset retirement obligations costs assumed[1]	23,651	12,116	31,652
Asset retirement obligations costs properties sold[1]	(32)	(12,714)	
Asset retirement expenditures	(971)	(2,362)	
Total costs incurred	$ 765,977	$ 513,997	$ 491,642

(1) Asset retirement obligation costs reflect abandonment obligations assumed during the year and revisions to prior estimates. As a result of the disposition of our South Louisiana and Appalachian Basin assets during 2004, asset retirement obligations were reduced by $12.7 million. Actual retirement expenditures reflect plugging and abandonment costs during the year. For 2003, our presentation of asset retirement obligation costs incurred does not include the cumulative effect of adopting SFAS 143 Asset Retirement Obligations on January 1, 2003 of $42.5 million..

F-31

Table of Contents

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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,		
	2005	**2004**	**2003**
		(in thousands)	
Future cash inflows	$ 7,065,492	$ 4,558,560	$ 4,335,669
Future production costs	(1,403,934)	(812,800)	(764,373)
Future development costs	(874,327)	(545,192)	(369,121)
Future income taxes	(1,520,815)	(976,611)	(850,264)
Future net cash flows	3,266,416	2,223,957	2,351,911
10% annual discount for estimated timing of cash flows	(1,299,392)	(783,902)	(847,505)
Standardized measure of discounted future net cash flows	$ 1,967,024	$ 1,440,055	$ 1,504,406

At December 31, 2005, 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 $299.5 million, $205.2 million and $70.3 million, respectively, for 2006, 2007 and 2008.

Present Value of Future Net Cash Flows Relating to Proved Natural Gas and Oil Reserves

The 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. The table below provides a reconciliation of PV10 to the standardized measure of discounted future net

Table of Contents

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

cash flows. PV10 may be considered a non-GAAP financial measure as defined by the SEC s Regulation G. 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. However, PV10 is not a substitute for the standardized measure. Our PV10 measure and the standardized measure of discounted future net cash flows do not purport to present the fair value of our natural gas and oil reserves. Year-end prices per Mcf of natural gas used in making the present value and standardized measure determinations as of December 31, 2005, 2004 and 2003 were $8.15, $5.68 and $5.79, respectively. Year-end prices per Bbl of oil used for the same calculations were $53.27, $41.67 and $30.27, respectively for 2005, 2004 and 2003.

	As of December 31,		
	2005	**2004**	**2003**
		(in thousands)	
Net present value of future cash flows, before income taxes	$ 2,877,420	$ 2,071,976	$ 2,056,414
Future income taxes, discounted at 10%	(910,396)	(631,921)	(552,008)
Standardized measure of discounted future net cash flows	$ 1,967,024	$ 1,440,055	$ 1,504,406

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

	As of December 31,		
	2005	**2004**	**2003**
		(in thousands)	
Beginning of the year	$ 1,440,055	$ 1,504,406	$ 1,058,064
Revisions in quantities	(251,007)	(59,549)	(123,954)
Changes in prices	943,487	(34,170)	459,373
Changes in future development costs	(198,013)	(35,056)	(13,029)
Development costs incurred during the period	209,322	85,439	72,717
Extensions and discoveries, net of related costs	620,243	445,908	434,311
Sales of natural gas and oil, net of production costs	(787,013)	(639,555)	(486,382)
Accretion of discount	207,197	205,641	136,492
Net change in income taxes	(278,475)	(79,913)	(245,151)
Purchase of reserves in place	250,520	247,671	254,030
Sale of reserves in place	(4,904)	(110,877)	
Production timing and other	(184,388)	(89,890)	(42,065)
End of year	$ 1,967,024	$ 1,440,055	$ 1,504,406

Table of Contents

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2005, 2004 and 2003.

	Natural Gas (MMcf)			Crude Oil, Liquids and Condensate (MBbls)		
	2005	2004	2003	2005	2004	2003
Beginning of the year reserves	749,114	709,883	610,409	7,335	7,481	6,533
Revisions of previous estimates	(66,205)	(13,232)	(30,573)	1,097	(1,110)	(1,615)
Extensions and discoveries	135,336	162,719	140,632	1,395	255	117
Production	(105,809)	(115,855)	(99,965)	(1,417)	(1,355)	(1,307)
Purchase of reserves in place	81,704	67,806	89,380	3,000	2,245	3,753
Sales of reserves in place	(1,066)	(62,207)		(119)	(181)	
End of year reserves	793,074	749,114	709,883	11,291	7,335	7,481
Proved developed reserves:						
Beginning of year	475,080	487,867	435,629	3,535	4,073	2,413
End of year	506,212	475,080	487,867	6,933	3,535	4,073

	Natural Gas Equivalents (MMcfe)		
	2005	2004	2003
Beginning of year reserves	793,124	754,769	649,607
Revisions of previous estimates	(59,623)	(19,892)	(40,263)
Extensions and discoveries	143,706	164,249	141,334
Production	(114,311)	(123,985)	(107,807)
Purchase of reserves in place	99,704	81,276	111,898
Sales of reserves in place	(1,780)	(63,293)	
End of year reserves	860,820	793,124	754,769
Proved developed reserves:			
Beginning of year	496,290	512,305	450,107
End of year	547,810	496,290	512,305

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 13 Quarterly Financial Information (Unaudited)

The following represents our unaudited quarterly results for years ended December 31, 2005 and 2004. There 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
2005				
Total revenues[1]	$ 165,720	$ 175,817	$ 125,413	$ 154,593
Total operating expenses [2]	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[4]	$ 1.17	$ 1.53	$ 0.28	$ 0.69
Net income per share diluted[4]	$ 1.16	$ 1.51	$ 0.28	$ 0.69
2004				
Total revenues	$ 151,882	$ 172,776	$ 162,760	$ 163,021
Total operating expenses [3]	86,839	97,702	94,366	103,719
Income from operations	65,043	75,074	68,394	59,302
Net income	39,690	45,350	42,998	34,786
Net income per share basic[4]	$ 1.26	$ 1.49	$ 1.53	$ 1.23
Net income per share diluted[4]	$ 1.25	$ 1.47	$ 1.51	$ 1.21

(1) For the fourth quarter of 2005, total revenues includes a net loss of $116.5 million from hedging activities which includes the following items: a $164.5 million loss realized on contracts settled during fourth quarter; 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; 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.

(2) 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.

(3) During the fourth quarter of 2004, as a result of management organizational changes made within our company in November 2004, we recognized additional general and administrative expense of $5.1 million. The additional compensation expenses were a result of lump-sum severance payments and entitlements under executive employment agreements, including expenses related to the accelerated vesting of stock options and restricted stock. See Note 6 Subsequent Events *Lump Sum Payments to Executives Under Employment Contracts.*

(4) 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.

Table of Contents

INDEX TO EXHIBITS

EXHIBITS	DESCRIPTION
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(1)	Restated Bylaws of The Houston Exploration Company.
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 on April 26, 2005 (file No. 001-11899) and incorporated by reference herein).
4.4	Form of Certificate of Designation of Series A Junior Participation 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(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).
10.3(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.
10.4(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).
10.5(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).
10.6(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).
10.7[(2)]	Amendment to The Houston Exploration Company Executive Deferred Compensation Plan (filed as exhibit 99.2 to our Current Report on Form 8-K file dated January 31, 2006 (File No. 001-11899) and incorporated by reference).
10.8[(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).
10.9[(2)]	Amended and Restated 2004 Long Term Incentive Plan (filed as exhibit 99.1 to our Current Report on Form 8-K file dated January 31, 2006 (File No. 001-11899) and incorporated by reference).

Table of Contents

EXHIBITS	DESCRIPTION
10.10[(2)]	Supplemental Executive Retirement Plan dated January 1, 2006 (filed as exhibit 99.1 to our Current Report on Form 8-K dated January 6, 2006 (File No. 001-11899) and incorporated by reference).
10.11[(2)]	Employment Agreement dated July 16, 2001 between The Houston Exploration Company and Tracy Price (filed as Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 2001 (File No. 001-11899) and incorporated by reference).
10.12[(2)]	Employment Agreement dated September 29, 2003 between The Houston Exploration Company and Timothy R. Lindsey (filed as Exhibit 10.3 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 2003 (File No. 001-11899) and incorporated by reference).
10.13[(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).
10.14[(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).
10.15[(2)]	Amended and Restated Employment Agreement between The Houston Exploration Company and John H. Karnes 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).
10.16[(2)]	Separation Agreement and General Release dated December 8, 2005 between the 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) .
10.17[(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).
10.18[(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).
10.19[(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).
10.20[(2)]	Employment Agreement effective March 10, 2005, between John E. Bergeron, Jr. and The Houston Exploration Company (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).
10.21[(2)]	Employment Agreement effective April 13, 2005, between Jeffrey B. Sherrick and The Houston Exploration Company (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).

10.22[2]	Employment Agreement dated January 18, 2006 between Robert T. Ray and The Houston Exploration Company (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).
10.23[2]	Compensation Table for Executive Officers (filed as Exhibit 10.2 to our Quarterly Report on Form 10-Q for the period ended September 30, 2005 (File No. 001-11899) and incorporated by reference).
10.24[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).
10.25	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 (Exhibit 2.1 to Current Report on Form 8-K dated October 15, 2003 (file No. 001-11899) and incorporated by reference).

Table of Contents

EXHIBITS	DESCRIPTION
10.26	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).
10.27	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).
10.28	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).
10.29	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).
10.30	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).
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.