HOUSTON EXPLORATION CO
Form 10-K
March 12, 2004

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

FORM 10-K

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

For the fiscal year ended December 31, 2003

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 7% Senior Subordinated Notes due 2013	New York Stock Exchange

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

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 Regulations S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. Yes þ No o

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

The aggregate market value of the voting stock held by non-affiliates of the registrant was approximately $499,877,963, based on the closing sales price of $34.70 per share of the registrant s common stock as reported by on the New York Stock Exchange as of June 30, 2003, the last business day of the registrant s most recently completed second fiscal quarter.. For purposes of the preceding sentence only, all directors, executive officers and beneficial owners of ten percent or more of the common stock are assumed to be affiliates. As of March 11, 2004, 31,786,097 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 June 3, 2004 are incorporated by reference into Part III of this Form 10-K.

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Forward-Looking Statements

This Annual Report on Form 10-K (Annual Report) and the documents we have incorporated by reference into this Annual Report contain forward-looking statements as that term is defined in Section 27A of the Securities Act of 1933, as amended and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). In some cases, these forward-looking statements generally can be identified by words such as anticipate, believe, continue, expect, estimate, intend, may, plan, potential, predict, project, should, target, expressions. All statements under the caption Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations relating to our anticipated capital expenditures, future production and reserves, schedules, plans, timing of development, future cash flows and borrowings, pursuit of potential future acquisition opportunities and sources of funding for exploration and development are forward-looking statements. Although we believe that these forward-looking statements are based on reasonable estimates and assumptions, our expectations may not occur and we cannot guarantee that the anticipated future results will be realized. A number of factors could cause our actual future results to differ materially from those anticipated or implied in the forward-looking statements. These factors include, among other things, the volatility of natural gas and oil prices, the requirement to take write downs if natural gas and oil prices decline, our ability to meet our substantial capital requirements, our substantial outstanding indebtedness, the uncertainty of estimates of natural gas and oil reserves and production rates, our ability to replace reserves, and our hedging activities. For additional discussion of these and other risks, uncertainties and assumptions, see Items 1 and 2. Business and Properties and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations contained in this Annual Report. We undertake no obligation to publicly update or revise any forward-looking statements.

In this Annual Report, unless the context requires otherwise, when we refer to we, us and our, we are describing The Houston Exploration Company and its sole subsidiary on a consolidated basis.

If you are not familiar with the natural gas and oil terms used in this 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.

Part I.

Items 1. and 2. Business and Properties

Overview of Our Business

We are an independent natural gas and oil company engaged in the exploration, development, exploitation and acquisition of natural gas and oil reserves in North America. Natural gas is our primary focus. Our core areas of operations are South Texas, offshore in the shallow waters of the Gulf of Mexico, the Arkoma Basin of Oklahoma and Arkansas and the Appalachian Basin of West Virginia. During 2003, we began operations in the Rocky Mountain Region with an initial focus in the Uinta Basin of northeastern Utah.

We were founded in December 1985 as a Delaware corporation and began exploring for natural gas and oil on behalf of KeySpan Corporation. KeySpan, a member of the Standard & Poor s 500 Index, 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. As of December 31, 2003, THEC Holdings Corp., an indirect wholly owned subsidiary of KeySpan, owned approximately 55% of the outstanding shares of our common stock.

In February 2003, KeySpan divested three million shares of our common stock. KeySpan has publicly announced it does not consider its investment in Houston Exploration a part of its core asset group and that it may sell or dispose of all or a portion of its non-core assets, including its investment in our company. Because market conditions are unpredictable, KeySpan is unable to determine if or when any additional dispositions of all or a portion of its remaining ownership interest in our company will take place.

Our corporate offices are located at 1100 Louisiana Street, Suite 2000, Houston, Texas 77002. Our telephone number is (713) 830-6800.

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Investment Strategy

We strive to maximize shareholder value while maintaining our financial flexibility by pursuing an investment strategy involving elements of each of the following activities:

Exploitation. Exploitation, both onshore and offshore, is one of our core competencies and the cornerstone of our investment strategy. We invest in exploitation and development properties intended to generate stable and growing cash flows from which we can fund future expansion of our business and reserve base.

Exploration. Founded as an exploration company, we continue to invest in exploratory prospects to supplement the reserves added through our exploitation activities. We generate the majority of our exploration prospects through our in-house geo-science personnel and currently have assembled a three-year inventory of offshore drilling prospects.

Acquisitions. We augment our exploration and exploitation activities with acquisitions of new properties that we believe conform to our operating philosophy and offer unexploited reserve potential.

We typically fund exploitation and exploration activities out of cash flows from operations. We typically fund acquisitions through our revolving bank credit facility. When we incur debt in connection with an acquisition, we focus on prompt repayment in order to minimize our debt service obligations. Our current debt levels provide flexibility to continually review and adjust our capital budgets during the year based on operational developments, commodity prices, service costs, acquisition opportunities and numerous other factors.

Operating Philosophy

Natural Gas Emphasis. Our production and reserve base is heavily weighted toward natural gas. We have focused our growth and operations in the United States. There is intense competition for the acquisition and development of domestic reserves. Since natural gas can only be transported from overseas in liquefied form and is thus more difficult to import than crude oil, we believe natural gas is better insulated from the price volatility associated with global geopolitical instability. The lease operating expense associated with natural gas properties is also typically less than oil properties, which allows us to maintain our low per-unit cost structure.

Operating Control. Whenever possible, we prefer to operate our properties because this allows us more control over the nature and timing of capital expenditures and overall operating expenses. As operator, we supervise production, maintain production records, employ or contract for field personnel, distribute revenues and perform other functions. As operator, we receive reimbursement for direct expenses incurred, as well as monthly per-well producing and drilling overhead reimbursements at rates customarily charged in the area by unaffiliated third parties. We currently operate approximately 85% of our wells.

Geographic Focus. By concentrating our operations within geographically focused areas, we can manage a large asset base with a relatively small number of employees and can integrate additional properties at relatively low incremental costs. Our strategy of focusing drilling activities on properties in relatively concentrated offshore and onshore areas permits us to more efficiently utilize our base of geological, engineering, exploration and production experience in these regions. At December 31, 2003, 90% of our reserves were located in our three core areas: South Texas, the Gulf of Mexico and the Arkoma Basin. Future growth opportunities may likely require the addition of new core areas.

Operating Environment. We focus our operations in areas that are conducive to low cost operations, avoiding areas where fractionalized ownership issues, local regulation or lack of a qualified workforce would drive up operational, legal and other costs.

Cash Flow Hedging. We maintain an active hedging program designed to reduce the impact of commodity price fluctuations and provide more predictable cash flows that allow us to better plan our capital expenditures. We utilize a variety of hedging strategies, including fixed price swaps, options and collars under which we are assured a minimum floor price for our production and the benefit of price increases up to a predetermined ceiling price. Depending on the outlook for future prices and the state of the derivatives markets, we may hedge up to 80% of our production for 2004 and up to 70% for 2005.

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Properties and Operating Areas

The table below summarizes certain data for our core operating areas for the year ended December 31, 2003.

Activity and Balances as of or for the Year Ended December 31, 2003

Area	Average Daily Production	Total Production	Total Proved Reserves	Percentage Total Proved Reserves	Total Wells Drilled	
					Total	Successful
	(MMcfe/d)	(MMcfe)	(MMcfe)		(Gross)	(Gross)
South Texas	140	51,137	315,437	42%	77	56
Gulf of Mexico	122	44,607	246,650	33%	17	9
Arkoma Basin	23	8,385	111,316	15%	51	46
West Virginia	3	1,194	50,455	7%	2	2
Other onshore	7	2,484	30,911	3%		
Total	295	107,807	754,769	100%	147	113

South Texas. Our South Texas properties are concentrated in the Charco, 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 total, our South Texas properties cover approximately 65,000 net acres and we own interests in 581 producing wells, 476 of which we operate. Our average working interest is 82%. Average well depth is between 8,000 to 12,500 feet with production from the Wilcox formations.

When we acquired the Charco Field in July 1996, it had approximately 150 producing wells and average daily production was 38 MMcfe per day, net to our interest. In December 2001, we expanded our existing production and reserve base with the acquisition of the Alexander, Hubbard and South Laredo Fields, and again, in May 2002, with the acquisition of the Northeast Thompsonville Field. In total, our net South Texas production has more than tripled since July 1996, to an average of 143 MMcfe per day during December 2003. Over the course of seven and a half years, we have drilled 228 successful wells at an average success rate of 82%, produced 241 Bcfe and added 444 Bcfe in reserves through drilling and acquisitions.

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, High Island, East Cameron, Vermilion and South Timbalier areas. In October 2003, we added to our existing production base through the acquisition of 11 producing fields in the central Gulf of Mexico. The properties were purchased for a net $147.5 million and had estimated proved reserves of 88.5 Bcfe. Of the proved reserves acquired, 75% were classified as natural gas and 68% were proved undeveloped. Taking into account the recent acquisition and as of December 31, 2003, we hold interests in 127 blocks in federal and state waters, of which 69 are developed. We operate 32 of our developed blocks, which accounts for approximately 65% of our offshore production. We have a total of 80 producing platforms and production caissons of which we operate 49.

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. We have approximately 36,000 net acres under lease and we own working interests in 275 producing natural gas wells, 170 of which we operate. Wells average a depth of 5,500 feet and production is from the Atoka formation. As a result of the downspacing from 640 acres to 160 acres per well approved by the Arkansas Oil and Gas Commission in September 2002, we were able to more than double the number of wells drilled during 2003 from 24 wells in 2002 to 51 wells in 2003. By December 2003, our average daily production had increased by 35% from an average of 20 MMcfe per day in 2002 to 27 MMcfe per day, net to our interest. In September 2003, the Arkansas Oil and Gas Commission approved further downspacing to 80 acres per well, allowing for continued expansion of our drilling opportunities.

*Appalachian Basin***.** Our property base is located in central West Virginia and includes the Belington, Clarksburg and Seneca Upshur Fields located in Barbour, Randolph, Upshur and Mingo Counties of West Virginia. On December 31,

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2003, we extended our existing reserve base through an acquisition of additional producing properties. The properties acquired are adjacent to our existing production base and include 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. We purchased net proved reserves of 23.4 Bcfe for $27.9 million. Average daily production is estimated at approximately 4 MMcfe per day, net to our interest. The properties purchased cover approximately 146,000 gross (83,950 net) acres and include approximately 774 producing wells. In addition, the interests acquired include approximately 300 wells in which we will have an overriding royalty interest. Giving effect to the acquisition and as of December 31, 2003, we have approximately 129,000 net acres under lease and own working interests in 1,411 wells of which we operate 1,304 or 92%. Our average working interest is 73%.

Other Onshore. During 2003, we also owned properties in East Texas and South Louisiana. East Texas properties are located in the Willow Springs Field in Gregg County, Texas and include interests in 24 wells of which we operate 23. The South Louisiana properties are located in the South Lake Arthur and Lake Pagie Fields located primarily in Vermillion and Terrebonne Parishes. On February 4, 2004 we completed the sale of our 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 net proceeds from the sale of $12.8 million were used to repay borrowings under our revolving bank credit facility.

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Natural Gas and Oil Reserves

The following table summarizes the estimates of our historical net proved reserves as of December 31, 2003, 2002 and 2001, and the present values attributable to these reserves at these dates. The reserve data and present values were fully engineered by Netherland, Sewell & Associates, Inc. and Miller and Lents, Ltd., independent petroleum engineering consultants.

	As of December 31,		
Net Proved Reserves:	**2003**	**2002**	**2001**
		(in thousands)	
Natural gas (MMcf)	709,883	610,409	568,208
Oil and natural gas liquids (MBbls)	7,481	6,533	6,605
Total (MMcfe)	754,769	649,607	607,838
Present value of future net revenues before income taxes[1]	$1,955,197	$1,326,314	$714,416
Standardized measure of discounted future net cash flows[2]	$1,504,406	$1,058,064	$551,525

(1) The present value of future net revenues attributable to our reserves was prepared using prices in effect at the end of the respective periods presented, discounted at 10% per annum (PV10) on a pre-tax basis. In accordance with current Securities and Exchange Commission (SEC) guidelines, the PV10 includes the fair value of our natural gas and oil hedges in place at December 31, 2003, 2002 and 2001 of a negative $101.2 million, a negative $38.6 million and a positive $65.8 million, respectively. Year-end prices per Mcf of natural gas used in making the present value determinations as of December 31, 2003, 2002 and 2001 were $ 5.79, $4.35 and $2.38, respectively. Year-end prices per Bbl of oil used in making the present value determinations as of December 31, 2003, 2002 and 2001 were $30.27, $28.74 and $17.78, respectively.

(2) The standardized measure of discounted future net cash flows represents the PV10 after income tax and 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 inflows from our hedging program.

In accordance with applicable requirements of the SEC, we estimate our net proved reserves and future net revenues using sales prices estimated to be in effect as of the date we make the reserve estimates. We hold the estimates 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. Volatility is expected to continue and price fluctuations 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 on Form 10-K represent only estimates. Reservoir engineering is a 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.

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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 during the year ended December 31, 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.

	For the Year Ended December 31, 2003					
	Successful - Productive		Unsuccessful - Dry		Total Drilled	
	Gross	Net	Gross	Net	Gross	Net
Exploratory:						
South Texas	3	3.0	3	3.0	6	6.0
Gulf of Mexico	6	2.4	8	3.6	14	6.0
Arkoma			1	0.4	1	0.4
Total exploratory	9	5.4	12	7.0	21	12.4
Development:						
South Texas	53	51.3	18	17.5	71	68.8
Gulf of Mexico	3	2.0			3	2.0
Arkoma	46	28.6	4	2.5	50	31.1
West Virginia	2	2.0			2	2.0
Other onshore						
Total development	104	83.9	22	20.0	126	103.9
Total wells drilled	113	89.3	34	27.0	147	116.3

As of December 31, 2003, we were drilling or participating in the drilling of 16 gross (12.2 net) wells. Of these wells, through March 12, 2004, 12 gross (9.7 net) wells have been determined to be successful and 3 gross (23 net) were unsuccessful with the remaining 1 gross (0.2 net) wells still in progress.

Productive Wells

The following table sets forth the number of productive wells in which we owned an interest as of December 31, 2003. Productive wells consist of producing wells and wells capable of production, including wells awaiting connections. Wells that are completed in more than one producing horizon are counted as one well. The day-to-day operations of natural gas properties are the responsibility of an operator designated under an operating agreement.

	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	476	461.4	105	14.3					581	475.7
Gulf of Mexico	72	58.5	43	16	16	12.3	10	1.4	141	88.2
Arkoma Basin	170	116.4	105	24.8					275	141.2
West Virginia	1,304	985.1	107	47.3					1,411	1,032.4
Other onshore	28	17.7	24	6.0			5	1.2	57	24.9

Total	2,050	1,639.1	384	108.4	16	12.3	15	2.6	2,465	1,762.4

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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, 2003. 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, 2003					
	Undeveloped		Developed		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
South Texas	20,296	15,564	65,478	49,213	85,774	64,777
Gulf of Mexico	223,965	180,479	299,333	183,448	523,298	363,927
Arkoma Basin	18,958	7,088	59,707	28,322	78,665	35,410
West Virginia	2,755	2,755	204,518	125,707	207,273	128,462
Rocky Mountain	198,458	182,905			198,458	182,905
Other onshore	442	39	9,389	5,002	9,831	5,041
Total	464,874	388,830	638,425	391,692	1,103,299	780,522

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, 2003									
	2004		2005		2006		2007		2008	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
South Texas	6,532	4,920	6,979	5,499	1,081	594				
Gulf of Mexico	50,502	44,742	43,511	42,071	26,499	22,017	46,181	37,921	57,274	33,727
Arkoma Basin							2,750	898		
West Virginia										
Rocky Mountain	3,270	3,265	31,410	31,218	2,560	2,016	22,474	22,410	2,774	2,774
Other onshore	383	8	56	30	2	1				
Total	60,687	52,935	81,956	78,818	30,142	24,628	71,405	61,229	60,048	36,501

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 sell substantially all of our production to a variety of purchasers under short-term (usually one month) contracts or spot gas purchase contracts ranging anywhere from one to 30 days, all at market prices. 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 portions of our natural gas production to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in gas prices. For more a detailed discussion, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations General and Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

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We incur gathering and transportation expenses to move our natural gas from the wellhead to a purchaser-specified delivery point. These expenses vary based on the volume and distance shipped, and the fee charged by the third party transporter. We do not have any material transportation agreements and we have not contracted for firm capacity for which we would pay monthly demand charges. Our natural gas and oil are transported through third party gathering systems and pipelines. Transportation space on these gathering systems and pipelines 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 read the section entitled Risk Factors Operating Hazards and Uninsured Risks.

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 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 is intensifying 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 and which, in many instances, have been engaged in the oil and gas business for a much longer time than we have. Our ability to acquire additional properties and to discover new reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in this highly competitive environment.

Seasonal Nature of Business

The demand for natural gas often decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation. In addition, pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations.

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Regulation

The oil and gas industry is extensively regulated by numerous federal, state and local authorities. 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, 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 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 in which we operate also regulate:

- 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 which 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.

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, 2003, we did not incur any material capital expenditures for environmental control facilities. As of the date of our report, we are not aware of any environmental issues or claims that will require material capital expenditures during 2004 or that will have a material impact on our financial position or results of operations.

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

Resource Conservation and Recovery Act. The Resource Conservation and Recovery Act 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. At this time, 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 believe we are in substantial compliance

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

Federal Clean Air Act. The Federal Clean Air Act restricts the emission of air pollutants and affects both onshore and offshore oil and gas operations. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to incur capital costs in order to remain in compliance. In addition, EPA has developed and continues to develop more stringent regulations governing emissions of toxic air pollutants. These regulations may increase the costs of compliance for some facilities. We 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. If the Protocol enters into force, it would 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.

Natural Gas Sales 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, unregulated, 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 less stringent regulatory approach recently pursued by FERC and Congress 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, 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 issues 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, gathering is regulated by FERC under the Outer Continental Shelf Lands Act. The Outer Continental Shelf Lands Act requires open access and non-discriminatory rates, but does not provide for cost-based rates. Although its policy is still in flux, FERC has recently reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting gas to point-of-sale locations.

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Risk Factors Affecting Our Business

A Decline in Natural Gas and Oil Prices May Adversely Affect Our Financial Results.

As an independent natural gas and oil producer, the revenues we generate from our operations are highly dependent on the price of, and demand for, natural gas and oil. Even relatively modest changes in natural gas and oil 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;
- the price of foreign imports;
- overall domestic and global economic conditions;
- terrorist attacks or military conflicts;
- political and economic conditions in oil producing countries, including the Middle East and South America;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the level of consumer product demand;
- weather conditions;
- domestic and foreign governmental regulations; and
- the price and availability of alternative fuels.

If natural gas and oil prices decline, the amount of natural gas and oil we can economically produce will be reduced, which may result in a material decline in our revenues.

We May Be Required to Take Writedowns of the Carrying Value of Our Natural Gas and Oil Properties.

We may be required under full cost accounting rules to write down the carrying value of our natural gas and oil properties when natural gas and oil prices are low 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 Regulation S-X Rule 4-10 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 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 the 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 2003 as a function of our higher finding and development cost 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, we will become more susceptible to ceiling test writedowns in low price environments.

The Success of Our Business Depends Upon Our Ability to Find, Develop and Acquire Oil and Gas 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 increasingly more difficult to find 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. If we are not able to replace reserves at sufficient levels, the amount of credit available to us may decrease

since the maximum amount of borrowing capacity available under our revolving credit facility is based, at least in part, on the estimated quantities of our proved reserves.

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Our Acquisition and Investment Activities May Not Be Successful.

The successful acquisition of producing properties requires assessment of reserves, future commodity prices, operating costs, 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 with respect to acquired properties. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We are generally not entitled to contractual indemnification for environmental liabilities and we typically acquire structures on a property on an as is basis.

We 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 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. Without continued employment of capital, our oil and gas reserves will decline. We may not be able to obtain debt or equity financing, and cash generated by operations or available under our revolving credit facility may not be sufficient to meet our capital requirements.

The Amount of Our Outstanding Indebtedness May Restrict Our Financial Flexibility.

Our level of indebtedness affects our operations in a number of ways. Our revolving credit facility and the indenture governing our senior subordinated notes contain covenants that require a substantial portion of our cash flow from operations to be dedicated to the payment of interest on our indebtedness. Funds dedicated to debt service payment will not be available for other purposes. Further, other covenants in these agreements require us to meet the financial tests specified in these agreements and establish other restrictions that limit our ability to borrow additional funds or dispose of assets. They may also affect our flexibility in planning for, and reacting to, changes in business conditions. Future acquisition and development activities may require us to significantly alter our capitalization structure, which may alter our indebtedness. Our ability to meet our debt service obligations and reduce our total indebtedness will depend upon our future performance.

Estimates of Proved Reserves and Future Net Revenue May Change.

The estimates of proved reserves of natural gas and oil included in this document are based on various assumptions. The accuracy of any reserve estimate is a function of the quality of available data, engineering, geological interpretation and judgment and the assumptions used regarding quantities of recoverable natural gas and oil reserves and prices for crude oil and natural gas. 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. 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, results of drilling, testing and production and changes in crude oil and natural gas prices after the date of the estimate may result in downward revisions.

The Oil and Gas 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 of 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;
- explosions;
- encountering formations with abnormal pressures;

blowouts;

cratering;

unexpected operational events;

- pipeline ruptures; and
- spills.

We are insured against some, but not all, of the hazards associated with our business. As a result, we may be liable or sustain losses that could be substantial due to events that are not insured.

Our Reserves, Production and Cash Flow are Highly Dependent upon Operations that are Concentrated in Three Primary Areas.

During 2003, approximately 96% of our production was generated from three primary areas of operations with 46% from our South Texas, 41% from offshore Gulf of Mexico and 8% from the Arkoma Basin. 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 tropical weather disturbances, some of which can be severe enough to cause substantial damage to facilities and production infrastructure. We are not insured against all potential losses. Losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our financial condition and results of operations.

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 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.

Our Hedging Activities Could Result in Financial Losses or Could Reduce Our Income.

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently and may in the future enter into hedging arrangements for a significant portion of our natural gas and oil production. For 2004 we have entered into derivative instruments relating to about 70% of our planned production utilizing a variety of instruments, including fixed price swaps, collars and options. Many derivative instruments that we employ require us to make cash payments to the extent the NYMEX index exceeds a predetermined price, thereby limiting our ability to realize the benefit of increases in natural gas prices. As we typically index 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-indexed derivative instruments are deemed ineffective in hedging price fluctuations at our sales points. 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 diminution of our liquidity. Lastly, an attendant risk exists in hedging activities that the counterparty in any derivative transaction cannot or will not perform under the instrument and that we will not realize the benefit of the hedge. It is also important to note that it is not practical to hedge the cash flows relating to all of our production, and we therefore retain the risk of a price decrease on our un-hedged volumes.

We May Incur Substantial Costs to Comply With Environmental and Other Governmental Regulations.

Our exploration and production operations are regulated extensively at the federal and state levels. Environmental and other governmental regulations have increased the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. We have made and will continue to make all necessary expenditures, both financial and managerial, in our efforts to comply with the requirements of environmental and governmental regulations. 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 increasing impact on our operations. Accordingly, increasingly strict environmental laws, regulations and enforcement policies and claims for damages to property, employees, other persons and the environment resulting from our operations, could result in substantial costs and liabilities in the future.

Competitive Industry Conditions May Adversely Affect Our Results of Operations.

As an independent natural gas and oil producer, we face strong competition in all aspects of our business. Many of our competitors are large, well-established companies that have substantially larger operating staffs and greater capital

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resources than we do. These companies may be able to pay more for productive natural gas and oil properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial and human resources permit.

The Inability of One or More of Our Customers to Meet Their 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. In addition, our natural gas futures and swap contracts also expose us to credit risk in the event of nonperformance by counterparties.

Potential Conflicts of Interest With Our Majority Stockholder.

A variety of conflicts of interest between KeySpan and our public stockholders may arise as a result of KeySpan s controlling interest in our company. As of the date of this report, KeySpan owns approximately 55% of our common stock, and we are one of their indirect subsidiaries. KeySpan is in a position to control:

- the election of the entire Board of Directors;
- the outcome of the vote on all matters requiring the vote of our stockholders;
- all matters relating to our management;
- the acquisition or disposition of our assets, including the sale of our business as a whole;
- payment of dividends on our common stock;
- the future issuance of our common stock or other securities; and
- hedging, drilling, operating and acquisition expenditure plans.

The Chairman of our Board of Directors, Robert B. Catell, is also the Chairman of the Board of Directors and Chief Executive Officer of KeySpan. In addition to Mr. Catell, six of our eleven other directors are currently or previously affiliated with KeySpan: Gerald Luterman is Executive Vice President and Chief Financial Officer of KeySpan; H. Neil Nichols is Senior Vice President of Corporate Development and Asset Management of KeySpan; Robert J. Fani is President of KeySpan Energy Services and Supply; Stephen W. McKessy is a member of KeySpan s Board and serves on the Audit Committee and James Q. Riordan, former Chairman of our Audit Committee, retired from KeySpan s Board in May 2002.

Our Majority Stockholder has Indicated its Desire to Divest.

In February 2003, KeySpan divested three million shares of our common stock. KeySpan has publicly announced it does not consider its investment in Houston Exploration a part of its core asset group and that it may sell or dispose of all or a portion of its non-core assets, including its investment in our company. Because market conditions are unpredictable, KeySpan is unable to determine if or when any additional dispositions of all or a portion of its remaining ownership interest in our company will take place.

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Employees

As of December 31, 2003, we had 170 full time employees, 117 of whom are located at our headquarters in Houston, Texas and the remainder of whom are located in our South Texas, Arkansas, West Virginia, 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

We currently lease approximately 69,000 square feet of office space in Houston, Texas at 1100 Louisiana Street, where our principal offices are located. We maintain approximately 2,250 square feet of office space in Denver, Colorado at 700 17th Street. In addition, we maintain field operations offices in South Texas, Arkansas, West Virginia and East Texas.

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 internet website at http://www.houstonexploration.com as soon as reasonably practicable after we electronically file such material with, or 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 website at www.houstonexploration.com under the heading Corporate Governance. We intend to promptly disclose on our website information about any 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 Corporate Governance Committee, and Compensation Committee are also available on the Shareholder/Financial section of our website 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 website 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.

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

Item 3. Legal Proceedings

We are not a party to any material pending legal or governmental proceedings, other than ordinary routine litigation incidental to our business. Where the ultimate outcome and impact of any proceeding cannot be predicted with certainty, our management believes that the resolution of any proceeding 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, 2003.

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Part II.

Item 5. Market for the Registrant s Common Equity and Related Stockholder Matters

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, 2002 through December 31, 2003 as reported on the New York Stock Exchange:

Year Ended December 31, 2003	High	Low
First Quarter	$31.45	$25.81
Second Quarter	35.20	26.72
Third Quarter	36.28	31.25
Fourth Quarter	37.70	33.35

Year Ended December 31, 2002	High	Low
First Quarter	$33.65	$27.32
Second Quarter	31.85	28.40
Third Quarter	31.45	23.80
Fourth Quarter	34.00	28.21

As of March 11, 2004, 31,786,097 shares of common stock were outstanding, and we had approximately 40 stockholders of record and approximately 4,500 beneficial owners.

Dividends

We have never declared or paid any cash dividends and do not anticipate declaring any dividends in the foreseeable future. We plan to retain our cash for the operation and expansion of our business, including exploration, development and acquisition activities. In addition, our revolving bank credit facility and the indenture governing our 7% senior subordinated notes due 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.

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Item 6. Selected Financial Data

The following table shows selected financial data derived from our consolidated financial statements for each of the five years in the period ended December 31, 2003. 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,				
	2003	2002	2001	2000	1999
	(in thousands, except per share data)				
Income Statement Data:					
Revenues:					
Natural gas and oil revenues[1]	$491,440	$344,295	$387,156	$277,487	$157,137
Other	1,312	1,086	1,353	1,738	1,147
Total revenues[1]	492,752	345,381	388,509	279,225	158,284
Expenses:					
Lease operating expense	47,072	33,976	25,291	23,553	18,406
Severance tax	15,958	9,487	11,035	9,757	5,444
Transportation expense [1]	10,387	9,317	7,652	6,892	6,557
Asset retirement accretion expense	3,668				
Depreciation, depletion and amortization	197,530	171,610	128,736	89,239	74,051
Writedown in carrying value			6,170		
General and administrative, net	19,542	13,077	17,110	8,928	4,150
Total operating expenses	294,157	237,467	195,994	138,369	108,608
Income from operations	198,595	107,914	192,515	140,856	49,676
Other (income) expense [2]	(15,746)	(9,070)	119	1,752	
Interest expense, net	8,342	7,398	2,992	11,361	13,307
Income before income taxes	205,999	109,586	189,404	127,743	36,369
Income tax provision	72,187	39,092	66,803	42,485	11,748
Income before cumulative effect of change in accounting principle	$133,812	$ 70,494	$122,601	$ 85,258	$ 24,621
Cumulative effect of change in accounting principle [3]	2,772				
Net income	$131,040	$ 70,494	$122,601	$ 85,258	$ 24,621
Earnings per share:					
Basic:					
Income per share before cumulative effect of change in accounting principle change	$ 4.30	$ 2.31	$ 4.06	$ 3.06	$ 1.03
Cumulative effect of change in accounting principle [3]	0.09				
Net income per share basic	$ 4.21	$ 2.31	$ 4.06	$ 3.06	$ 1.03
Fully Diluted:					
Income per share before cumulative effect of change in accounting principle	$ 4.29	$ 2.28	$ 4.00	$ 3.02	$ 0.95
	(0.09)				

Cumulative effect of change in accounting principle [3]					
Net income per share fully diluted	$ 4.20	$ 2.28	$ 4.00	$ 3.02	$ 0.95
Weighted average shares	31,097	30,569	30,228	27,860	23,906
Weighted average shares diluted	31,213	30,878	30,645	28,213	28,310
Ratio of earnings to fixed charges [4]	13.6x	7.6x	12.8x	5.5x	2.0x

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	Years Ended December 31,				
	2003	2002	2001	2000	1999
	(in thousands)				
Cash Flow Data:					
Net cash provided by operating activities	$390,832	$243,869	$358,032	$200,791	$110,072
Net cash used in investing activities	461,822	252,125	368,277	184,512	147,654
Net cash provided by (used) in financing activities	55,528	17,668	9,189	(22,106)	48,439

	At December 31,				
	2003	2002	2001	2000	1999
Balance Sheet Data:					
Working capital (deficit)	$ (36)	$ 10,550	$ 34,314	$ 19,746	$ (71,219)
Property, plant and equipment, net	1,371,129	1,151,068	938,761	705,390	610,116
Total assets	1,509,065	1,138,816	1,059,092	837,384	678,483
Long-term debt and notes	302,000	252,000	244,000	245,000	281,000
Stockholders equity	735,534	592,789	565,881	396,742	217,590

(1) For all periods presented, we applied Emerging Issues Task Force (EITF) No. 00-10 Accounting for Shipping and Handling Fees and Costs. For the years ended December 31, 2001, 2000 and 1999, transportation expenses previously reflected as a reduction to natural gas and oil revenues were added back to revenues and reflected as a separate component of operating expense.

(2) For 2003 and 2002, other income includes $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. Additionally, 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. Please see Note 2 Long-Term Debt and Notes. For 2001 and 2000, other expense of $0.2 million and $1.8 million, respectively, represents nonrecurring expenses incurred in connection with a strategic review of alternatives for Houston Exploration and KeySpan s investment in our company, including the possible sale of all or a portion of Houston Exploration. See Note 6 Related Party Transactions.

(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.

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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 conditions. 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 statements. 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 Risk Factors Affecting Our Business found on page 13 for additional discussion of some of these factors and risks.

Overview of Our Business

We are an independent natural gas and oil company engaged in the exploration, development, exploitation and acquisition of natural gas and oil reserves in North America. Natural gas is our primary focus. Our core areas of operations are South Texas, offshore in the shallow waters of the Gulf of Mexico, the Arkoma Basin of Oklahoma and Arkansas and the Appalachian Basin of West Virginia. During 2003, we commenced operations in the Rocky Mountain Region, with an initial focus in the Uinta Basin of northeastern Utah. We operate in one segment as each of our operating areas has similar economic characteristics and each meets the criteria for aggregation as defined in SFAS 131.

Source of Our Revenues

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 utilize derivative instruments to hedge future sales prices on a significant portion of our natural gas production. The use of certain types derivative instruments may prevent us from realizing the benefit of upward price movements. At December 31, 2003, KeySpan held 55% of our common stock. KeySpan has indicated a desire to divest of its shares held in our company. In February 2003, KeySpan divested three million shares of our common stock. KeySpan has publicly announced it does not consider its investment in Houston Exploration a part of its core asset group and that it may sell or dispose of all or a portion of its non-core assets, including its investment in our company. Because market conditions are unpredictable, KeySpan is unable to determine if or when any additional dispositions of all or a portion of its remaining ownership interest in our company will take place.

Principal Components of Our Cost Structure

*Lifting Costs.*The day-to-day costs incurred to bring hydrocarbons out of the ground and to the market together with the daily costs incurred to maintain our producing properties. These costs include: lease operating expense, severance tax and transportation expense.

Depreciation, Depletion and Amortization (DD&A). The systematic expensing of the capital costs incurred to acquire, explore and develop natural gas and oil. As a full cost company, we capitalize all direct costs associated with our acquisition, exploration and development efforts, including interest and certain general and administrative costs, and apportion these costs to each unit of production sold through DD&A expense. Generally, if reserve quantities are revised up or down, the DD&A rate per unit of production will change inversely. When the depreciable base increases or decreases, the DD&A rate will move in the same direction.

Asset Retirement Accretion Expense (ARO). The systematic, monthly accretion of future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and other facilities.

General and Administrative (G&A). Overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, managing our production and development operations and legal compliance are included in our general and administrative expense (G&A). We capitalize G&A directly related to our acquisition, exploration and development activities.

Interest. We typically finance acquisitions with borrowings under our revolving bank credit facility, and longer term, with public traded debt instruments. As a result, we incur substantial interest expense that correlates to both fluctuations in interest rates and our acquisition activity. Acquisitions are a critical element of our growth strategy. We expect to continue to incur significant interest expense as we continue to grow. We capitalize interest directly related to our unevaluated properties and certain properties under development, which are not being amortized.

Income Taxes. We are generally subject to a 35% federal income tax rate. For income tax purposes, we are allowed deductions for accelerated depreciation, depletion and intangible drilling costs that reduce our current tax liability. Prior to 2003, all of our taxes, both

federal and state, were deferred; however, during 2003, we utilized all of our net operating loss carryforwards and as a result, we recognized current income tax expense and will continue to recognized current tax expense as long as we are generating taxable income.

Industry Environment

We currently operate exclusively in North America. After over 100 years of active natural gas and oil exploration and production within the lower 48 states and Gulf of Mexico, the region has matured and production of natural gas and oil has declined. Numerous technological advances during this timeframe, including increasingly sophisticated geophysical tools that allow more accurate identification of reservoirs , horizontal and other drilling technologies that facilitate and enhance the extraction process, and advanced completion techniques have accelerated production rates and hastened depletion. While new discoveries are still being made in North America, the frequency and size of these discoveries is declining. As a result,

domestic natural gas and oil production as a whole may have peaked and is expected to decline in the future, with the exception of regions such as the Rocky Mountains, which we believe, continues to hold the prospect for production growth.

In this mature environment, companies will find it increasingly difficult to replace their reserves through traditional exploration and development efforts, and companies will increasingly be forced to rely on acquisitions to sustain their growth. Our future success growing our reserve base at an acceptable finding cost will depend in large part on our ability to acquire new proven reserves and unevaluated acreage on which we can explore for new discoveries. We maintain a very active acquisition program and will continue to devote significant resources to identifying and pursuing both tactical acquisitions that augment our existing property base as well as substantial, strategic acquisitions.

We anticipate that the continued decline of the North American gas basin 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 will rise as the industry makes fewer discoveries of smaller reserve size. For full cost companies such as ours, this will result in higher finding and development costs and higher DD&A rates and ultimately the increased likelihood of a writedown in carrying value of our natural gas and oil properties. In addition, we think lease operating expenses will continue to rise as producers are forced to make operational enhancements to maintain aging fields.

Like any commodity, the price that we receive for the gas we produce is largely a function of supply and demand. Demand for natural gas is affected by general economic conditions, such as growth in the space heating, industrial and power generation segments, and seasonal conditions. Demand has also typically been impacted by seasonal fluctuations, with the peak demand during the winter heating season and summer air conditioning season. As natural gas is difficult to import, 80% to 85% of the United States natural gas demand in recent years has been supplied by domestic production. Imports from Canada have made up 10% to 15% of the United States natural gas needs and imports from a variety of other countries now make up for 1% to 2% of total supply in the form of liquefied natural gas, or LNG.

Situations involving over or under supply of natural gas can result in substantial price volatility. For example, concerns over the adequacy of natural gas in storage during the first quarter of 2003 resulted in prices exceeding $9.00 during the quarter and emerging 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 and into 2004. As a direct result, we were able to increase our net income, generate substantial cash flows to fund acquisitions, our capital budget and repay borrowings on our revolving bank credit facility. However, historically, commodity prices have been very volatile, and we expect the volatility to continue in the future. 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 comodity prices our ability to acquire, find and develop new reserves at economical costs.

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Critical Accounting Estimates

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

Asset Retirement Obligation. 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, the our credit adjusted risk free interest rate, the estimated settlement date of the liability and the estimated current cost to settle the liability which we compute from third party quotes. Changes in timing or to the original estimate of cash flows will result in changes to the carrying amount of the liability.

Derivative Instruments. Under SFAS 133, Accounting for Derivative Instruments and Hedging Activities, as amended, we reflect the fair market value of our derivative instruments on our balance sheet. Our estimates of fair value are determined by obtaining independent market quotes from third parties, as well as utilizing a Black-Scholes option valuation model that is based upon underlying forward price curve data, a risk-free interest rate and estimated volatility factors.

Recent Accounting Developments

SFAS 141, Business Combinations and SFAS 142, Goodwill and Intangible Assets, became effective on July 1, 2001 and January 1, 2002, respectively. These new standards emphasize a more precise evaluation of assets and their balance sheet classification as either tangible or intangible assets. We understand that the issue is under evaluation as to whether provisions of SFAS 141 and SFAS 142 may call for mineral rights held under lease or other contractual arrangements together with cash costs for the acquisition of natural gas and oil leasehold interests to be classified in the balance sheet as intangible assets. If these types of leasehold costs (both proved and unevaluated) are determined to be intangible assets, they would be classified separately from natural gas and oil properties as intangible assets on our balance sheets. This issue relates only to balance sheet classification and presentation and we do not believe it will have an effect on cash flows or results of operations. At December 31, 2003, if we applied the interpretation currently under discussion, undeveloped leasehold costs of $117.1 million and developed leasehold costs of $221.3 million, net of accumulated amortization, would be reclassified from tangibles to intangibles, representing costs incurred since June 30, 2001, the effective date of SFAS 141. At December 31, 2002, we had undeveloped leasehold costs of $49.5 million and developed leasehold costs of $111.5 million, net of accumulated amortization that would be reclassified from tangibles to intangibles. Consistent with current industry practice, we will continue to classify our natural gas and oil leasehold costs as tangible natural gas and oil properties until the Emerging Issues Task Force issues further guidance.

New Accounting Pronouncements

In November 2002, FASB issued Financial Interpretation No. (FIN) 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others. FIN 45 requires certain guarantees to be recorded at fair value, which is different from the previous practice of recording a liability only when a loss is probable and reasonably estimable, as those terms are defined in SFAS 5, Accounting for Contingencies. FIN 45 has a dual effective date. The initial recognition and measurement provisions are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure requirements in the interpretation are effective for financial statements for interim or annual periods ending after December 15, 2002. As of our December 31, 2003, and December 31, 2002, balance sheet dates, we did not have any guarantees of indebtedness of others and as a result, our adoption of FIN 45 did not have an effect on our financial statements.

In January 2003, the FASB issued FIN 46, Consolidation of Variable Interest Entities An Interpretation of Accounting Research Bulletin 51. FIN 46 addresses consolidation by business enterprises of variable interest entities (VIEs) and the primary objective is to provide guidance on the identification of, and financial reporting for, entities over which control is achieved through means other than voting rights; such entities are known as VIEs. FIN 46 requires an entity to consolidate a VIE if the entity has a variable interest (or combination of variable interests) that will absorb a majority of the entity s expected losses if they occur, receive a majority of the entity s expected residual returns if they occur or both. This guidance applies immediately to VIEs created after January 31, 2003, and to VIEs in which an enterprise obtains an interest after that date. However, on October 8, 2003, the FASB decided to grant a broader deferral of the implementation of FIN 46. Pursuant to this deferral, public companies must complete their evaluations of VIEs that existed prior to February 1, 2003, and the consolidation of those for which they are the primary beneficiary for financial statements issued for the first period ending after December 15, 2003. For calendar year companies, consolidation of previously existing VIEs will be required in their December 31, 2003, financial statements. We have completed our evaluation

of FIN 46 and because we do not believe that we have any VIEs there is no impact to our consolidated financial statements.

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Overview of 2003 Results

Strong energy commodity prices were the primary force behind a record year for operations, earnings and cash flows. The increase in our cash flows allowed for increased capital spending for drilling, acquisitions, and the repayment of debt, all of which improved our balance sheet. During 2003:

We generated, $131.0 million in net income, an 86% increase from 2002, which was primarily attributable to a 37% increase in average realized natural gas prices;

We produced a total of 108 Bcfe, and increased our average daily production rate by 5% to 295 MMcfe, per day, and we closed out 2003 with a record production rate of 319 MMcfe per day during December;

We increased our total net proved reserves by 16% to 755 Bcfe with a pre-tax net present value, discounted at 10%, of future net cash flows of $2.0 billion;

We replaced 198% of our production by adding 213 Bcfe of net proved reserves through a combination of drilling and acquisitions;

We drilled a record 147 wells, 130 onshore and 17 offshore, of which 113 were successful reflecting a success rate of 77%;

We participated in and brought on-line our first deep shelf discovery at High Island 115 and had a 40% success rate on deep shelf tests for the year;

We completed our largest acquisition of producing properties to date in October, by purchasing 88.5 Bcfe of net proved reserves in the Gulf of Mexico from Transworld Exploration and Production Inc. for a net $147.5 million;

We added to our West Virginia production base in December by acquiring producing properties adjacent to our existing fields and acquired 23.4 Bcfe of net proved reserves for a net $27.9 million. In conjunction with this acquisition and in an effort to improve our onshore asset portfolio;

We agreed to divest of our South Louisiana properties, effective November 1, 2003,and sold 12.3 Bcfe of net proved reserves for a net $12.8 million in February 2004;

We established a new operating area in the Rocky Mountain Region by leasing more than 200,000 net undeveloped acres throughout southwestern Montana, the Green River Basin of southwestern Wyoming and in the Uinta Basin of northeastern Utah and successfully drilled our first exploratory well in the Uinta Basin during December, with an estimated 30 wells planned for 2004;

We recouped and recognized as other income $21.6 million ($14.0 million net of tax) of prior years severance tax expense pursuant to the high-cost/tight-gas formation designation received during the second half of 2002 for a portion of our South Texas production;

We generated $390.8 million in net cash flows from operating activities and invested a net $460.0 million in natural gas and oil properties, which included $175.4 million for producing property acquisitions;

We added 141 Bcfe in total proved reserves through the drill bit, 112 Bcfe through acquisitions and incurred downward revisions of 40 Bcfe bringing our all-in finding and development cost to $2.16 per Mcfe for 2003 and $1.93 per Mcfe for a five-year average;

We assisted KeySpan in divesting three million shares of our common stock which reduced their ownership interest to 55%;

We took advantage of favorable long-term interest rates by redeeming our $100 million of 8-5/8% senior subordinate notes due 2008 and issuing $175 million of 7% senior subordinated notes due 2013; and,

We announced our 2004 capital expenditure budget of $315 million.

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Operating and Financial Results for 2003 Compared to 2002

	For the Years Ended December 31,			
	2003	2002	Variance	% change
Summary operating information:				
Operating revenues	$492,752	$345,381	$147,371	43%
Operating expenses	294,157	237,467	56,690	24%
Income from operations	198,595	107,914	90,681	84%
Net income	$131,040	$ 70,494	$ 60,546	86%
Production:				
Natural gas (MMcf)	99,965	97,368	2,597	3%
Oil (MBbls)	1,307	859	448	52%
Total (MMcfe) [2]	107,807	102,522	5,285	5%
Average daily production (MMcfe/day)	295	281	14	5%
Average Sales Prices:				
Natural Gas (per Mcf) realized [1]	$ 4.55	$ 3.32	$ 1.23	37%
Natural Gas (per Mcf) unhedged	5.23	3.16	2.07	66%
Oil (per Bbl) realized [1]	28.15	23.99	4.16	17%
Oil (per Bbl) unhedged	28.46	23.99	4.47	19%

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

(2) Mcfe is defined 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.

Operating Income

Higher natural gas prices were the primary factor contributing to our 86% increase in net income and our 84% increase in operating income in 2003 over 2002. Adding to the effects of higher commodity prices was an increase of 5% in production volume. Increased revenues were offset in part by a 24% increase in operating costs due primarily to the continued expansion of our operations combined with an increase in costs to maintain our existing production base together with higher DD&A rates for 2003.

Commodity Prices

Our average wellhead price during 2003, before the effects of our hedging program, was $5.23 per Mcfe up 66% over 2002. This increase in natural gas prices during 2003 accounted for $207 million, or approximately 89% of our $232 million increase, in revenues before the effects of our hedging program.

Our increase in natural gas and oil revenues was substantially offset by a $68.3 million loss from our hedging program, which lowered the price that we realized on our natural gas production by $0.68 Mcf during the period. The largest portion of this loss resulted from fixed price swaps for natural gas that we entered into during the fourth quarter of 2001 in connection with our acquisition of producing properties in South Texas. As a result of these swaps, we effectively fixed the price that we received on approximately 40 MMcf per day at $3.19, resulting in a loss of $32 million, or 47% of our total hedging loss for 2003.

Production Volume

The 5% increase in production for the current year is a result of newly developed production combined with additions from acquisitions made in 2003 and 2002.

Onshore, our daily production rates increased 12% from an average of 155 MMcfe/day during 2002 to 173 MMcfe/day during 2003. The increase in onshore production is primarily attributable to newly developed production in South Texas and Arkoma. In South Texas we drilled 56 successful wells and increased our average daily production rate to 140 MMcfe/day during 2003 from 123 MMcfe/day in 2002. In Arkoma, we more than doubled the number of wells drilled in 2002 by successfully drilling 46 wells during 2003. The impact of the newly developed production was seen in the fourth quarter of 2003 as our average daily rate in Arkoma increased to 25 MMcfe/day. For 2004, we expect our

onshore daily production rate to grow by an estimated 5% or to average between 180 and 184 MMcfe/day.

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Offshore, our production decreased 3% from an average of 126 MMcfe/day during 2002 to an average of 122 MMcfe/day during 2003. For the first nine months of 2003, offshore production averaged 117 MMcfe/day as production declines due to maturing reservoirs from existing key fields, Mustang Island A-31/32, High Island 39, West Cameron 587 and South Marsh Island 253, were greater than new production added from wells and facilities brought on-line throughout 2003. Specifically, we had disappointing results at South Timbalier 314/317 that was brought on-line in early 2003. Contributing to the year-over-year production decline was the effect of shifting approximately $40 million of our 2002 offshore capital expenditure budget to our onshore region to fund the May 2002 acquisition of producing properties in South Texas from Burlington Resources. During the fourth quarter of 2003, offshore production increased by approximately 16% to an average rate of 136 MMcfe/day as we began to absorb the properties acquired from Transworld in mid-October and experienced production increases from newly developed fields, in particular, High Island 115 and High Island 47. For 2004, we expect offshore production to increase by 25% to approximately 155 MMcfe/day, which will include an estimated 35 MMcfe per day from the Transworld properties.

Effects of Hedging

For 2003, we realized an average natural gas price of $4.55 per Mcf, which was 87% or $0.68 per Mcf lower than our average unhedged natural gas price or wellhead price of $5.23 for the period. Included in natural gas revenues is a loss of $67.9 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 No. 133. The ineffectiveness was a result of changes during the period in the price differentials between the index price of the derivative contract, which uses a New York Mercantile Exchange (NYMEX) index, 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 2002, we realized an average gas price of $3.32 per Mcf, which was 105% of the average unhedged natural gas price of $3.16 for the period. This resulted in natural gas revenues that were $16.4 million higher than the revenues we would have achieved if hedges had not been in place during the period. For 2002, our natural gas revenues included a realized gain of $16.4 million from hedging activities.

For 2003, we realized an average oil price of $28.15 per Bbl, which was 99% or $0.31 per Bbl lower than the average unhedged price of $28.46 per Bbl for the period. As a result of oil hedging activities, oil revenues for 2003 were $0.4 million lower than the revenues we would have achieved if oil hedges had not been in place during the period. We had no oil hedges in place during 2002 and realized an average oil price of $23.99 per Bbl.

Operating Expenses

	Years Ended December 31,			
Operating Expenses (per Mcfe):	**2003**	**2002**	**Variance**	**%change**
Lease operating expense	$0.44	$0.33	$0.11	33%
Severance tax	0.15	0.09	0.06	67%
Transportation expense	0.10	0.09	0.01	11%
Asset retirement accretion expense	0.03		0.03	100%
Depreciation, depletion and amortization	1.83	1.67	0.16	10%
General and administrative, net	0.18	0.13	0.05	38%
Total operating expenses per unit of production	$2.73	$2.31	$0.42	18%

Lease Operating Expense. The increase in lease operating expenses for 2003 is attributable to the continued expansion of our operations both onshore and offshore. Our overall operating expenses are increasing as we add new wells and production facilities and continue to maintain production from existing, maturing properties. Specific increases for 2003 were incurred for production enhancement and compression, insurance and contract services. In addition, we incurred $2.6 million in non-recurring expenses associated with workovers.

The acquisition of the Transworld properties in October 2003 caused our lease operating expense on a per unit basis to increase from an average of $0.42 per Mcfe for the first nine months of 2003 to $0.47 per Mcfe during the fourth quarter of 2003. The majority of the Transworld fields were originally developed by major oil and gas producers and due to their age and complexity, lease operating expenses for these properties are expected to be significantly higher than that of our existing offshore fields. Our plan for 2004 is to reduce operating expenses per unit of production for these properties through integration and exploitation. We estimate that our lease operating expenses will average $0.54 per Mcfe during the first quarter of 2004.

Severance Tax. Severance tax is a function of volume and revenues generated from onshore production. The increase in severance tax expense and severance tax per Mcfe for 2003 is due to a 66% increase in average wellhead prices for natural gas during 2003 combined with a 12% increase in onshore production during 2003.

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Depreciation, Depletion and Amortization. The increase in our DD&A expense for 2003 was primarily a result of a higher depletion rate combined with a 5% increase in production volumes for 2003. Our depletion rate increased as a result of:

- downward reserve revisions related to reservior performance of approximately 40 Bcfe;
- the addition of more costs to our depreciation base with fewer additions for reserves as our average finding and development cost increased from $1.75 per Mcfe during 2002 to $2.16 per Mcfe during 2003; and
- a 52% increase in our estimated future development costs at year end, the majority of which was due to the proved undeveloped classification of 68% of the reserves acquired from Transworld.

For 2004, based on our current reserve base, we expect our depreciation, depletion and amortization rate to average $2.00 per Mcfe.

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

General and Administrative per Mcfe:	Years Ended December 31, 2003	2002	Variance	% change
Gross general and administrative expense	$ 0.32	$ 0.28	$0.04	14%
Operating overhead reimbursements	(0.02)	(0.02)		
Capitalized general and administrative expense	(0.12)	(0.13)	0.01	-8%
General and administrative expense, net	$ 0.18	$ 0.13	$0.05	38%

The increase in aggregate general and administrative expense is due primarily to the expansion of our workforce that corresponds to the continued expansion of our operations. As our workforce expands, we have experienced an increase in salaries and related employee benefit expenses that include increases in our incentive compensation expense together with expense for stock compensation as we adopted the fair value expense provisions for stock options under SFAS No. 123, as amended, in January 2003. Our rent expense increased as we expanded our leased office space in downtown Houston to accommodate our growing workforce and opened an office in Denver to coordinate our expansion into the Rocky Mountains. Our legal, audit and accounting expenses increased as we implemented new corporate governance policies required by the Sarbanes Oxley Act of 2002 and engaged an outside firm to perform ongoing internal auditing functions.

The higher rate per Mcfe during 2003 reflects the increase in our aggregate general and administrative expenses combined with a proportional reduction in the amount of general and administrative expense capitalized during 2003. The mix of our capitalized expenses has changed as we incurred more costs during 2003 that were not directly related to our natural gas and oil exploration and development activities. We expect that as our company continues to grow and expand, our general and administrative expenses will increase. For 2004, we estimate that net general and administrative expenses will average between $0.19 and $0.20 per Mcfe.

Other Income and Expense, Interest and Taxes

Other Income and Expense. For 2003, Other Income and Expense includes two components: debt extinguishment expenses totaling $5.9 million ($3.9 million net of tax); and income of $21.6 million ($14.0 million net of tax) related to the recoupment of prior years severance tax expense. 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. In 2002, we recognized as other income, $9.1 million ($5.9 million net of tax) related to the recoupment of prior years severance tax expense. For future periods, we do not expect to recognize additional refunds in excess of $1 million. The debt extinguishment expenses were incurred in June pursuant to the call and early redemption of our $100 million 8-5/8% notes and the issuance of $175 million of 7% senior subordinated notes. We paid a premium for early redemption of $4.3 million and incurred a non-cash charge of $1.6 million to write-off the balance of the unamortized costs associated with issuing the $100 million 8-5/8% senior subordinated notes.

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Interest Expense, Net of Capitalized Interest.

Interest Expense and Average Borrowings	Years Ended December 31, 2003	2002	Variance	% change
Gross interest	$ 15,642	$ 15,373	$ 269	2%
Capitalized interest	(7,300)	(7,975)	675	-8%
Interest expense, net of amounts capitalized	8,342	7,398	944	13%
Average borrowings	$240,000	$263,600	23,600	9%
Average interest rate	6.08%	5.38%	0.70%	13%

During 2003, our average borrowings decreased and our average interest rate increased as we replaced our existing fixed debt of $100 million at 8-5/8% with new fixed debt of $175 million at 7% and used excess proceeds from the newly issued debt to repay outstanding borrowings under our revolving bank credit facility which bears interest at lower rates that averaged 3.4% during both 2003 and 2002. In addition, capitalized interest decreased during 2003. Our capitalized interest is a function of unevaluated properties and the decrease corresponds to the decrease in our average unevaluated property balance throughout 2003 prior to our October 2003 acquisition of producing properties from Transworld.

Income Tax Provision. During 2003, our current provision increased to $12.5 million as we depleted our net operating loss carryforwards and moved to a tax paying status where, as in prior years, all federal and state income taxes were deferred.

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Operating and Financial Results for 2002 Compared to 2001

	For the Years Ended December 31,			
	2002	2001	Variance	% change
Summary operating information:				
Operating revenues	$345,381	$388,509	$(43,128)	-11%
Operating expenses	237,467	195,994	41,473	21%
Income from operations	107,914	192,515	(84,601)	-44%
Net income	$ 70,494	$122,601	$(52,107)	-43%
Production:				
Natural gas (MMcf)	97,368	87,095	10,273	12%
Oil (MBbls)	859	459	400	87%
Total (MMcfe)	102,522	89,849	12,673	14%
Average daily production (MMcfe/day)	281	246	35	14%
Average Sales Prices:				
Natural Gas (per Mcf) realized [1]	$ 3.32	$ 4.32	$ (1.00)	-23%
Natural Gas (per Mcf) unhedged	3.16	4.18	(1.02)	-24%
Oil (per Bbl) realized [1]	23.99	22.83	1.16	5%

[1] Average realized prices include the effect of hedges.

Operating Income

Significantly lower natural gas prices were the primary factor contributing to our 43% decrease in net income and our 44% decrease operating income in 2002 from 2001. Operating expenses increased by 21% due to a combination of the continued expansion of our operations, an increase in costs to maintain our existing production base and higher DD&A rates. Offsetting the effects of lower natural gas prices and higher operating expenses was an increase of 14% in production volume.

Commodity Prices

Our average wellhead price during 2002 was $3.16 per MMcfe, before the effects of our hedging program, down 24% over 2001. Natural gas and oil revenues, before effects of hedging, decreased by $46.3 million during 2002. The effect of the decrease in natural gas prices from 2001 levels accounted for $99.3 million of the decrease which was offset in part by an increase of $52 million attributable to the 14% increase in production volume and $1.0 million related to the increase in oil prices during 2002. For 2002, our natural gas and oil revenues were increased by a $16.4 million gain from our hedging program, which increased our average realized price for natural gas production by $0.32 Mcf during the period.

Production Volume

During 2002, our production increased 14%. The increase was primarily attributable to production added from properties acquired in South Texas since December 31, 2001 together with newly developed production generated from our subsequent development and workover programs initiated on these acquired properties during 2002. During 2002, we successfully drilled and completed a total of 84 new wells, consisting of 75 onshore wells and 9 offshore wells. Of the 75 wells drilled onshore, 54 were drilled in South Texas, of which 27 were drilled on our newly acquired acreage with the balance being drilled in our Charco Field.

Onshore, our daily production rates increased 32% from an average of 117 MMcfe/day during 2001 to an average of 155 MMcfe/day during 2002. Properties acquired from Conoco Inc. on December 31, 2001 accounted for 33 MMcfe/day of the increase for 2002 and properties acquired from Burlington Resources on May 30, 2002 accounted for 7 MMcfe/day of the increase for 2002. Production from our Charco Field in South Texas averaged 83 MMcfe/day during the current year and remained unchanged from 2001 rates. Production from all other onshore areas (Arkoma, East Texas, West Virginia and South Louisiana) decreased 2 MMcfe/day or approximately 6% from an average of 34 MMcfe/day during 2001 to 32 MMcfe/day during 2002 primarily a result of a decrease in production in South Louisiana due principally to natural reservoir decline.

Offshore, our production decreased 2% from an average of 129 MMcfe/day during 2001 to an average of 126 MMcfe/day during 2002. During January 2002, we initiated production from our newly completed facilities at Vermilion 408. We

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added new facilities and a series of new wells throughout 2002 at East Cameron 81, 82 and 83. During September and October 2002 we evacuated and shut-in offshore platforms and facilities due to Tropical Storms Faye and Isidore and Hurricane Lili. We estimate that we shut-in approximately 750 MMcfe or 2 MMcfe/day on an annualized basis. In October 2002, we acquired from KeySpan incremental working interests in 17 offshore wells that were initially developed under a joint exploration agreement with KeySpan (see Note 6 - Related Party Transactions *KeySpan Joint Venture*) from 1999 through 2002. Overall, for the year 2002, increments in production growth resulting from our acquisition and our new exploration and development projects was offset by natural production declines in existing properties.

Effects of Hedging

As a result of hedging activities, we realized an average gas price of $3.32 per Mcf for 2002, which was $0.16 per Mcf or 105% greater than the average unhedged natural gas price of $3.16 that we otherwise would have received if hedges had not been in place during the year. For 2002, our hedging activities resulted in a gain of $16.4 million that is included in natural gas and oil revenues. For 2001, we realized an average gas price of $4.32 per Mcf, which was $0.14 per Mcf or 103% higher than the average unhedged natural gas price of $4.18. As a result, natural gas and oil revenues for 2001 include a realized gain of $12.9 million from hedging activities.

Operating Expenses

	Years Ended December 31,			
	2002	**2001**	**Variance**	**% change**
Operating expenses (per Mcfe):				
Lease operating expense	$0.33	$0.28	$ 0.05	18%
Severance tax	0.09	0.12	(0.03)	-25%
Transportation expense	0.09	0.09		
Depreciation, depletion and amortization	1.67	1.43	0.24	17%
Writedown in carrying value of properties		0.07	(0.07)	100%
General and administrative, net	0.13	0.19	(0.06)	-32%
Total operating expenses per unit of production	$2.31	$2.18	$ 0.13	6%

Lease Operating Expense. The increase in both lease operating expenses and lease operating expenses per unit is attributable to the continued expansion of our operations combined with an increase in expenses incurred during 2002. Onshore operations expanded with the acquisition of approximately 304 new producing wells in South Texas from the December 31, 2001 acquisition from Conoco Inc. and the May 30, 2002 acquisition from Burlington Resources. Excluding the incremental expenses relating to newly acquired properties, the increase in our onshore lease operating expenses is due primarily to increased ad valorem taxes and increased compression expenses. Ad valorem taxes increased as a result of the high natural gas prices experienced in 2001. Compression expenses increased during the second half of 2002 as we implemented a project in the Charco Field to boost production by adding compressors to streamline and lower gathering system pressure. Offshore, our lease operating expenses increased due to the addition

of production facilities at Vermilion 408 and East Cameron 81, new processing fees attributable to oil production at Vermilion 408 where we have chosen to have a third party process our oil rather than constructing our own oil facilities, the implementation of compression projects to enhance production capabilities at several of our existing facilities and finally, an increase in well control insurance premiums during the current year.

Severance Tax. The decrease in severance tax expense is primarily due to $1.3 million recorded during the fourth quarter of 2002 related to refunds of expense incurred during the current year. 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 (see Note 9 - Commitments and Contingencies *Severance Tax Refund*). In addition to the $1.3 million recorded as a reduction to current year severance tax expense, we recognized as other non-operating income $9.1 million for refunds relating to prior periods. Excluding the effect for the $1.3 million, severance tax would have been $10.8 million and $0.11 per Mcfe during 2002 compared to $11.0 million and $0.12 per Mcfe for 2001. Expense is comparable because wellhead prices were 25% lower during 2002 as compared to wellhead prices received during 2001; however, our onshore production increased by 32% during 2002 which accounts for the decrease in the adjusted severance tax on a per unit basis.

Depreciation, Depletion and Amortization. The increase in depreciation, depletion and amortization expense was a result of higher production volumes combined with a higher depletion rate. Our depletion rate increased in 2002 as we completed the evaluation of several properties that were classified as unproved at December 31, 2001. As evaluation is completed, the costs associated with these properties were reclassified into our amortization base. The higher depletion rate is a result of a combination of adding costs to the full cost pool with fewer new reserves being added from exploration and developmental drilling together with an overall increase in our finding and development costs. We believe that higher finding costs are

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being experienced across the industry, particularly for companies our size whose primary area of exploration is the Outer Continental Shelf or the shallow waters of the Gulf of Mexico.

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

	Years Ended December 31,			
General and Administrative per Mcfe:	**2002**	**2001**	**Variance**	**%change**
Gross general and administrative expense	$ 0.28	$ 0.34	$(0.06)	-18%
Less effects of 2001 on-time charge		(0.06)	(0.06)	100%
Gross general and administrative expense, adjusted	0.28	0.28		
Operating overhead reimbursements	(0.02)	(0.01)	(0.01)	100%
Capitalized general and administrative expense	(0.13)	(0.14)	0.01	-7%
General and administrative expense, net	$ 0.13	$ 0.13	$	

Included in aggregate and net administrative expenses during 2001 were payments totaling $5.2 million, $0.06 per Mcfe in 2001, made in connection with the termination of former executive officers employment contracts. Excluding the one-time charges during 2001, both aggregate and net general and administrative expenses for 2002 are comparable to 2001. Per unit expense were unchanged as aggregate dollars increased by 8% year over year (excluding the effect of the one-time charge in 2001) as a result of the 14% increase in production for 2002. Aggregate expenses incurred increased as a result of the overall expansion of our business, our workforce and our office space. Payroll and employee benefits, rent and utilities and legal, accounting and consulting expenses all increased during 2002. Overhead reimbursements increased due to an increase in the number of producing properties operated that have third party working interests. On a percentage basis, we capitalized approximately the same percentage of general and administrative expenses during both 2002 and 2001.

Other Income and Expense, Interest and Taxes

Other Income and Expense. For 2002, we recorded other income of $9.1 million relating to refund of severance tax paid in prior periods and recorded pursuant to our receipt of a high-cost/tight sand designation for a portion of our South Texas production (see Note 9 Commitments and Contingencies *Severance Tax Refund*). For 2001, we incurred an additional $0.1 million in expenses relating to a strategic review initiated in the fourth quarter of 1999 and completed in the first quarter of 2000. In September 1999, together with KeySpan, our majority stockholder, we had announced our intention to review strategic alternatives for our company and KeySpan s investment in our company. Consideration was given to a full range of strategic transactions including the possible sale of all or a portion of our assets. On February 25, 2000, we announced, together with KeySpan, that the review of strategic alternatives for Houston Exploration had been completed.

Interest Expense, Net of Capitalized Interest.

	Years Ended December 31,			
Interest Expense and Average Borrowings	**2002**	**2001**	**Variance**	**%change**
Gross interest expense	$ 15,373	$ 15,034	$ 339	2%
Capitalized interest	(7,975)	(12,042)	4,067	-34%
Interest expense, net of amounts capitalized	$ 7,398	$ 2,992	$ 4,406	147%
Average borrowings	$263,600	$190,900	$72,700	38%
Average interest rate	5.38%	7.43%	$ 0.05	-28%

During 2002, aggregate interest increased slightly by 2% as our average outstanding borrowing increased and our average interest rate decreased. Net interest expense increased substantially during 2002 as we capitalized 34% less interest as a result of a decrease in exploratory drilling during 2002. Our capitalized interest is a function of exploratory drilling and unevaluated properties, both of which were at lower levels during 2002.

Income Tax Provision. The provision for income taxes decreased due to the 42% decrease in pre-tax income during 2002 as a result of the combination of a decrease in natural gas revenues and increases in both operating expenses and net interest expense.

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Liquidity

Capital Requirements

Our principal requirements for capital are to fund our capital investment program and to satisfy our contractual obligations, primarily the repayment of long-term debt. Our capital investments include the following:

- Costs of acquiring and maintaining our lease acreage position and our seismic resources;
- Costs of drilling and completing new natural gas and oil wells;
- Costs of installing new production infrastructure;
- Costs of maintaining, repairing, and enhancing existing natural gas and oil wells;
- Costs related to plugging and abandoning unproductive or uneconomic wells; and
- Indirect costs related to our exploration activities, including payroll and other expense attributable to our exploration professional staff.

Our capital expenditure budget for 2004 has been set at an initial level of $315 million. We are the designated operator of approximately 85% of our wells. Operating allows us the ability to exercise control over the magnitude and timing of our capital program and provides us significant latitude to increase or decrease our spending in response to changes in price, operational developments or acquisition opportunities. To maintain flexibility of our capital program, we do not enter into material long-term obligations with any of our drilling contractors or service providers with respect to our operated properties. We do not include property acquisition costs in our 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 drilling results, natural gas prices, economic conditions and future acquisitions.

During 2003, we invested $459.9 million in natural gas and oil properties, which includes $175.4 million for the acquisition of producing properties, and $1.9 million for other property and equipment. Investments in non-natural gas and oil properties includes the expansion of our Houston office space together with upgrades to our information technology systems and equipment and compares to $2.4 million spent in 2002. For 2003, we spent 59% offshore and 36% onshore with the balance of 5% on capitalized interest and general and administrative costs. We completed the drilling of a record 147 gross wells (116.3 net) of which 77% or 113 (89.3 net) were successful and 38 (27.0 net) were unsuccessful with an additional 16 wells (12.2 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, total net proved reserve additions and our average all-in finding and development costs.

	Years Ended December 31,				
	(in thousands, except per unit amounts)				
	2003	2002	2001	2000	1999
Natural gas and oil capital expenditures					
Producing property acquisitions [1]	$175,420	$ 68,042	$ 69,010	$ 13,935	$ 21,746
Leasehold and lease acquisition costs[2]	56,076	36,458	48,068	32,599	25,696

Development	162,235	122,036	177,256	103,335	87,965
Exploration	66,259	26,536	72,056	34,160	12,257
Total natural gas and oil capital expenditures	$459,990	$253,072	$366,390	$184,029	$147,664
Proved reserve additions, net of revisions (MMcfe)	212,969	144,291	136,231	100,352	135,791
Finding and development cost per Mcfe	$ 2.16	$ 1.75	$ 2.69	$ 1.83	$ 1.09

(1) For 2002, producing property acquisitions is net of dispositions of $5.3 million.

(2) For 2003, 2002, 2001, 2000 and 1999, leasehold costs include capitalized interest and general and administrative expenses of $20.2 million, $21.1 million, $24.9 million, $23.3 million and $17.4 million, respectively.

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Future Commitments

In addition to our capital expenditure program, we are committed to making cash payments in the future on two types of contracts: note agreements and operating leases. We do not have off-balance sheet debt or other such unrecorded obligations, and we have not guaranteed the debt of any other party. 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, 2003. In addition to the contractual obligations listed on the table below, our balance sheet at December 31, 2003, reflects accrued interest payable on our revolving bank credit facility of $12,200 which is payable over the next 90-day period. We expect to make annual interest payments of $12.5 million per year on our $175 million of 7% senior subordinated notes due June 2013. And, we anticipate making income tax payments of approximately $30 million to $40 million in 2004.

	At December 31, 2003 Payments Due by Period				
	Total	1 year or less	2 - 3 years	4 - 5 years	after 5 years
	(in thousands)				
Contractual Obligations:					
Revolving bank credit facility, due July 2005	$127,000	$	$127,000	$	$
7% senior subordinated notes, due June 2013	175,000				175,000
Operating leases	8,343	1,470	4,374	2,500	
	310,343	1,470	131,374	2,500	175,000
Other Long-Term Obligations:					
Asset retirement obligations	92,357	7,543	13,555	6,825	64,435
Total contractual obligations and commitments	$402,700	$ 9,013	$144,929	$ 9,325	$239,435

Capital Resources

We intend to fund our capital expenditure program and contractual commitments through cash flows from our operations and borrowings under our revolving bank credit facility. To the extent we make a significant acquisition, we may also access public markets for debt. Our primary sources of cash during 2003 were from funds generated from operations and net proceeds received from the concurrent early redemption of our $100 million 8-5/8% senior subordinated notes and the issuance of $175 million 7% senior subordinated notes in June. Cash was used to fund acquisitions, exploration and development expenditures and to reduce debt under our revolving bank credit facility. We made aggregate cash payments of $18.4 million and $14.8 million, respectively, for interest and taxes. The table below summarizes the sources of cash during 2003 and 2002.

	Years Ended December 31,			
	2003	**2002**	**variance**	**% change**
Net income	$131,040	$ 70,494	$ 60,546	86%
Non-cash charges	268,228	211,555	56,673	27%
Cash from operations before changes in operating assets and liabilities	399,268	282,049	117,219	42%
Change (increase) in operating assets and liabilities	(8,436)	(38,180)	29,744	78%
Net cash provided by operating activities	390,832	243,869	146,963	60%
Net cash used for investments in property and equipment	461,822	252,125	209,697	83%
Net cash provided by financing activities	55,528	17,668	37,860	214%
Net (decrease) increase in cash	$ (15,462)	$ 9,412	$ (24,874)	-264 %

At December 31, 2003, we had a working capital deficit of $36,000, long-term debt of $302 million and $172.6 million of borrowing capacity available under our revolving bank credit facility. The working capital deficit was due to a current liability of $36.5 million representing the fair value of our derivative instruments. 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.

The 60% increase in net cash provided by operating activities during 2003 was primarily attributable to the increase in net income as a result of a 37% increase in average realized natural gas price, which includes the effects of hedging, together with a 5% increase in production volume, offset in part by a 24% increase in operating expenses. The increase in non-cash charges for 2003 was primarily a result of the increase in depreciation, depletion and amortization and deferred tax expense combined with current year charges for debt extinguishment, ineffectiveness of our derivative instruments and the cumulative effect of adopting SFAS 143 for asset retirement obligations. The increase in cash from operations was reduced in part by a net increase in operating assets and liabilities. Fluctuations in operating assets and liabilities are caused by the timing of cash receipts and disbursements.

During 2003, we took advantage of lower long-term interest rates to increase our available borrowing capacity under our revolving bank credit facility. In June, we called and redeemed our $100 million 8-5/8% notes due 2008 and issued $175 million 7% senior subordinated notes. The net proceeds from the $175 million notes were used to repay the outstanding principal and interest on the $100 million notes together with a premium of $4.3 million for early redemption. We used the remaining net proceeds to repay outstanding borrowings under our revolving bank credit facility and by the end of the third quarter of 2003, we had reduced our bank borrowings from $157 million at December 31, 2002 to zero at September 30, 2003. In the fourth quarter of 2003, we increased our bank borrowings to $127 million of which $115 million was used in October to finance a portion of the Transworld net purchase price of $147.5 million with the balance borrowed in December to fund a portion of the $27.9 million net purchase price for the EnerVest properties. For 2003, total long-term debt increased by a net $50 million as we increased fixed debt by $75 million and reduced our bank debt by $25 million compared to an increase of $8 million in total long-term borrowings during 2002. We received cash proceeds of $10.2 million for the issuance of common stock from the exercise of stock options compared to $9.7 million received in 2002. And, during the first quarter of 2003, we sold 3 million newly issued shares of our common stock in a public offering for net proceeds of $79.2 million, and simultaneously repurchased the same number of shares from KeySpan for $79.2 million.

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 Fleet National Bank as co-syndication agents and BNP Paribas as documentation agent. The credit facility provides us with a commitment of $300 million which may be increased at our request and with prior approval from Wachovia to a maximum of $350 million by adding one or more lenders or by allowing one or more lenders to increase their commitments. The credit facility is subject to borrowing base limitations. Our current borrowing base is $300 million and is redetermined semi-annually, with the next redetermination scheduled for April 1, 2004. Up to $25 million of the borrowing base is available for the issuance of letters of credit. The credit facility matures July 15, 2005, is unsecured and with the exception of trade payables, ranks senior to our 7% senior subordinated notes. At December 31, 2003, we were in compliance with all covenants. See Note 2 Long-term Debt and Notes for a summary of material covenants.

At December 31, 2003, we had borrowings under our revolving bank credit facility of $127 million and $0.4 million in outstanding letter of credit obligations. Subsequent to December 31, 2003, we repaid a net $37 million in outstanding borrowing under the facility, the primary source of these funds was proceeds received from the sale of our South Louisiana properties in early February 2004. At March 12, 2004, the date of this report, outstanding borrowings and letter of credit obligations under our revolving bank credit facility total $90.4 million.

In an effort to increase our borrowing capacity for property acquisitions, we are in the process of amending our current revolving bank credit facility to increase the borrowing capacity from $300 million to $400 million. The lenders and the primary terms and conditions of the new facility are expected to be consistent with the existing facility. The commitment is expected to increase to $400 million with the capability to increase the commitment to $450 million and we expect to have $40 million of the borrowing base available for letters of credit. The new facility is expected to become effective on April 1, 2004. Our initial borrowing base is expected to be $375 million and is scheduled for redetermination October 1, 2004. Outstanding borrowings are expected to continue to be unsecured and with the exception of trade payables, the new facility is expected to rank senior to our $175 million 7% subordinated notes. The new facility is expected to mature on April 1, 2008.

Senior Subordinated Notes. On June 10, 2003, we issued $175 million 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 which 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 $175 million 7% senior subordinated notes were issued in conjunction with the call and early redemption of our $100 million 8-5/8% senior subordinated notes due January 1, 2008. The redemption and payment of the call premium on the $100 million notes was funded with a portion of the proceeds received from the issuance of the $175 million 7% senior subordinated notes. Pursuant to the early redemption of the $100 million notes, we incurred debt extinguishment expenses totaling $5.9 million ($3.9 million net of tax) consisting of the call premium of $4.3 million together with a non-cash charge of $1.6 million for the write-off of the balance of the unamortized issue costs of the 8-5/8% notes. The debt extinguishment expenses of $5.9 million are included in the line item Other (Income) Expense on the Statement of Operations for the year ended December 31, 2003.

Access to Capital Markets. We currently have on file with the SEC a shelf registration statement covering the sale, from time to time, of our common stock, preferred stock, depositary shares and debt securities, or a combination of any of these securities. The shelf was filed in May 1999 and provided for an initial aggregate public offering price of up to $250 million. In February 2003, we sold 3,000,000 shares of our common stock to the public under the shelf registration statement and used the proceeds to concurrently repurchase three million shares of our common stock from KeySpan. Following that offering, we had approximately $169.8 million of capacity remaining under the shelf. In March 2004, we plan to terminate our existing shelf registration statement and replace it with a new shelf registration statement to be filed with the SEC covering the offering, from time to time, of up to $600 million of our common stock, preferred stock, depositary shares and debt securities, or a combination of any of these securities.

We believe that operating cash flow and our credit facility will be adequate to meet our capital and operating requirements for 2004. 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. Although we have no specific budget for property acquisitions, should attractive opportunities arise, we believe we could finance the additional capital expenditures with cash on hand, operating cash flow, additional borrowing under our revolving bank credit facility, issuances of additional equity or debt securities or development with industry partners.

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

Natural Gas and Oil Hedging

We utilize derivative commodity instruments to hedge future sales prices on a portion of our natural gas and oil production to achieve a more predictable cash flow, as well as to reduce our exposure to adverse price fluctuations of natural gas. Our derivatives are not held for trading purposes. While the use of hedging arrangements limits the downside risk of adverse price movements, it also limits increases in future revenues as a result of favorable price movements. 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 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 futures and swap contracts 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.

Our hedges are cash flow hedges and qualify for hedge accounting under SFAS No.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 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 other income or expense. In 2003, we recognized $1.9 million of ineffectiveness. The ineffectiveness was a result of changes during the period in the price differentials between the index price of the derivative contract, which uses a NYMEX index, 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. Ineffectiveness was not material prior to 2003.

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, 2003 and 2002 and provides the fair value at the end of each period.

	2003		2002	
	Before Tax	After Tax	Before Tax	After Tax
Change in Fair Value of Derivatives Instruments				
Fair value of contracts at January 1	$(38,772)	$(25,202)	$ 53,771	$ 34,951
(Gain) loss on contracts settled and realized	66,408	43,165	(16,358)	(10,633)
Fair value of new contracts when entered into during period	5,288			
(Decrease) in fair value of all open contracts	(69,786)	(44,091)	(76,185)	(49,520)
Fair value of contracts outstanding at December 31	$(36,862)	$(26,128)	$(38,772)	$(25,202)

Derivatives in Place as of the Date of Our Report

As of March 12, 2004, the date of this report, the following table summarizes, on a monthly basis, our natural gas hedges in place for 2004 and 2005. For each month of 2004, we have hedged approximately 70% of our estimated production or a total of 240,000 million British thermal units per day or MMBtu/day. For the three months January through March 2004, our floor price will average $4.472/MMBtu on 240,000 MMBtu/day and our ceiling price will average $5.021/MMBtu on 140,000 MMBtu/day, with no ceiling price on the remaining 100,000 MMBtu/day. For the remaining nine months of 2004, our floor price will average $4.264/MMBtu on 240,000 MMBtu/day and our ceiling price will average $5.845/MMBtu on 240,000 MMBtu/day. For each calendar month of 2005, we have 150,000 MMBtu/day hedged with an effective floor price of $4.589 and an effective ceiling price of $5.255. All amounts in the table below are in thousands, except for prices.

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Natural Gas Hedges	Options - Puts		Fixed Price Swaps		Collars		
Period	Volume (MMbtu)	NYMEX Contract Price	Volume (MMbtu)	NYMEX Contract Price	Volume (MMbtu)	NYMEX Contract Price	
						Avg Floor	Avg Ceiling
January 2004	3,100	$ 5.000	1,240	$ 4.960	3,100	$3.750	$5.045
February 2004	2,900	5.000	1,160	4.960	2,900	3.750	5.045
March 2004	3,100	5.000	1,240	4.960	3,100	3.750	5.045
April 2004			1,200	4.960	6,000	4.125	6.023
May 2004			1,240	4.960	6,200	4.125	6.023
June 2004			1,200	4.960	6,000	4.125	6.023
July 2004			1,240	4.960	6,200	4.125	6.023
August 2004			1,240	4.960	6,200	4.125	6.023
September 2004			1,200	4.960	6,000	4.125	6.023
October 2004			1,240	4.960	6,200	4.125	6.023
November 2004			1,200	4.960	6,000	4.125	6.023
December 2004			1,240	4.960	6,200	4.125	6.023
January 2005			1,550	4.766	3,100	4.500	5.500
February 2005			1,450	4.766	2,800	4.500	5.500
March 2005			1,550	4.766	3,100	4.500	5.500
April 2005			1,500	4.766	3,000	4.500	5.500
May 2005			1,550	4.766	3,100	4.500	5.500
June 2005			1,500	4.766	3,000	4.500	5.500
July 2005			1,550	4.766	3,100	4.500	5.500
August 2005			1,550	4.766	3,100	4.500	5.500
September 2005			1,500	4.766	3,000	4.500	5.500
October 2005			1,550	4.766	3,100	4.500	5.500
November 2005			1,500	4.766	3,000	4.500	5.500
December 2005			1,550	4.766	3,100	4.500	5.500

For natural gas, transactions are settled based upon the New York Mercantile Exchange or NYMEX price on the final trading day of the month. For oil, our swaps are settled against the average NYMEX price of oil for the calendar month rather than the last 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.

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Item 8. Financial Statements

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

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

None.

Item 9A. Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports we file under the Securities Exchange Act of 1934, as amended (Exchange Act) is communicated, processed, summarized and reported within the time periods specified in the SEC s rules and forms. We carried out an evaluation under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-14 of the Exchange Act), as of the end of the period covered by this report. Based on that evaluation, our principal executive officer and principal financial officer concluded that, as of December 31, 2003, our disclosure controls and procedures are functioning effectively as designed. There have been no changes in our internal control over financial reporting that occurred during the most recent fiscal quarter prior to the end of the period covered by this report that have materially affected, or are reasonable likely to materially affect, our internal controls over financial reporting.

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, Board Committees - Audit Committee, Board Committees Nominating and Corporate Governance Committee and Compliance with 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, 2003.

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 Executive Compensation and Election of Directors Director s Meetings and 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, 2003. 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 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 Securities Authorized for Issuance Under Equity Compensation Plans 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, 2003.

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 Certain Relationships and Related Party Transactions and Compensation Committee Interlocks and Insider 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, 2003.

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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 2003 and 2002 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, 2003.

Part IV.

Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

(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-37 for a description of the exhibits filed as a part of this report.

(b) Reports on Form 8-K.

Current Report on Form 8-K filed on October 29, 2003 to report under Item 2. Acquisition or Disposition of Assets our completion of the acquisition of the natural gas and oil properties from Transworld Exploration and Production Inc. on October 15, 2003.

Current Report on Form 8-K filed on November 6, 2003 to furnish under Item 12 - Results of Operations and Financial Conditions our earnings release for the third quarter of 2003 and the nine-month period ended September 30, 2003.

Current Report on Form 8-K filed on November 10,2003 to report under Item 11 - Temporary Suspension of Trading Under Registrant s Employee Benefit Plans our notice sent to our directors and executive officers subject to Section 16 of the Securities and Exchange Act of 1934, informing them of a blackout period under our 401(k) Plan and Trust.

Current Report on Form 8-K/A filed on December 4, 2003 that amended our Form 8-K filed on June 3, 2003 to report under Item 5 Other Events and Regulation FD Disclosure selected historical financial data and a reconciliation of non-GAAP financial measures to GAAP measures.

Current Report on Form 8-K filed on February 5, 2004 to furnish under Item 12 - Results of Operations and Financial Conditions our earnings release for the fourth quarter of 2003 and the twelve-month period ended December 31, 2003.

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SIGNATURES

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

THE HOUSTON EXPLORATION COMPANY

By: /s/ William G. Hargett

William G. Hargett
President and Chief Executive Officer

Date: March 12, 2004

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POWER OF ATTORNEY

Each person whose signature appears below hereby constitutes and appoints John H. Karnes 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	President, Chief Executive Officer and Director (Principal Executive Officer)	March 12, 2004
/s/ John H. Karnes John H. Karnes	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 12, 2004
/s/ James F. Westmoreland James F. Westmoreland	Vice President and Chief Accounting Officer (Principal Accounting Officer)	March 12, 2004
/s/ Robert B. Catell Robert B. Catell	Chairman of the Board of Directors	March 12, 2004
/s/ Gordon F. Ahalt Gordon F. Ahalt	Director	March 12, 2004
/s/ John U. Clarke John U. Clarke	Director	March 12, 2004
/s/ David G. Elkins David G. Elkins	Director	March 12, 2004
/s/ Robert J. Fani Robert J. Fani	Director	March 12, 2004
/s/ Harold R. Logan, Jr.	Director	March 12, 2004

Harold R. Logan, Jr.		
/s/ Gerald Luterman	Director	March 12, 2004
Gerald Luterman		
/s/ Stephen W. McKessy	Director	March 12, 2004
Stephen W. McKessy		
/s/ H. Neil Nichols	Director	March 12, 2004
H. Neil Nichols		
/s/ James Q. Riordan	Director	March 12, 2004
James Q. Riordan		
/s/ Donald C. Vaughn	Director	March 12, 2004
Donald C. Vaughn		

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Glossary of Oil and Gas Terms

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

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

Bbl/d. One barrel per day.

Bcf. Billion cubic feet.

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

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

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

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

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

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

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.

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.

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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.

Oil. Crude oil and condensate.

Present value. 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). The rule is available at the SEC website, http://www.sec.gov/divisions/corpfin/forms/regsx.htm#gas.

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

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required from recompletion.

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

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

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

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.

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INDEPENDENT AUDITORS REPORT

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

We have audited the accompanying consolidated balance sheets of The Houston Exploration Company (a Delaware corporation and an indirect 55% owned subsidiary of KeySpan Corporation) and subsidiary (the Company) as of December 31, 2003 and 2002, and the related consolidated statements of operations, stockholders equity and comprehensive income (loss) and cash flows for each of three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidences supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

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
February 17, 2004

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

	December 31,	
	2003	**2002**
Assets:		
Cash and cash equivalents	$ 2,569	$ 18,031
Accounts receivable	87,949	86,713
Accounts receivable Affiliate	6,733	3,106
Derivative financial instruments	3,458	
Inventories	1,071	1,432
Deferred tax asset	19,644	12,252
Prepayments and other	5,818	2,196
Total current assets	127,242	123,730
Natural gas and oil properties, full cost method Unevaluated properties	134,491	96,192
Properties subject to amortization	2,324,011	1,828,160
Other property and equipment	12,617	10,699
	2,471,119	1,935,051
Less: Accumulated depreciation, depletion and amortization	1,099,990	912,637
	1,371,129	1,022,414
Other non-current assets	10,694	4,924
Total Assets	$1,509,065	$1,151,068
Liabilities:		
Accounts payable and accrued expenses	$ 83,983	$ 78,175
Derivative financial instruments	35,592	35,005
Asset retirement obligation	7,703	
Total current liabilities	127,278	113,180
Long-term debt and notes	302,000	252,000
Derivative financial instruments	4,728	3,767
Deferred federal income taxes	251,425	188,215
Asset retirement obligation	84,654	
Other deferred liabilities	3,446	1,117

Total Liabilities	773,531	558,279
Commitments and Contingencies (see Note 9)		
Stockholders Equity:		
Common Stock, $.01 par value, 50,000,000 shares authorized and 31,437,581 and 30,954,018 shares issued and outstanding at December 31, 2003 and 2002, respectively	315	310
Additional paid-in capital	366,781	353,454
Unearned compensation	(808)	(107)
Retained earnings	395,374	264,334
Accumulated other comprehensive income	(26,128)	(25,202)
Total Stockholders Equity	735,534	592,789
Total Liabilities and Stockholders Equity	$1,509,065	$1,151,068

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

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

	For the Years Ended December 31,		
	2003	**2002**	**2001**
Revenues:			
Natural gas and oil revenues	$491,440	$344,295	$387,156
Other	1,312	1,086	1,353
Total revenues	492,752	345,381	388,509
Operating expenses:			
Lease operating	47,072	33,976	25,291
Severance tax	15,958	9,487	11,035
Transportation expense	10,387	9,317	7,652
Asset retirement accretion expense	3,668		
Depreciation, depletion and amortization	197,530	171,610	128,736
Writedown in carrying value of natural gas and oil properties			6,170
General and administrative, net of amounts capitalized	19,542	13,077	17,110
Total operating expenses	294,157	237,467	195,994
Income from operations	198,595	107,914	192,515
Other (income) expense	(15,746)	(9,070)	119
Interest expense, net of amounts capitalized	8,342	7,398	2,992
Income before income taxes	205,999	109,586	189,404
Provision for taxes	72,187	39,092	66,803
Income before cumulative effect of change in accounting principle	$133,812	$ 70,494	$122,601
Cumulative effect of change in accounting principle	(2,772)		
Net income	$131,040	$ 70,494	$122,601
Earnings per share:			
Net income per share basic			
Income before cumulative effect of change in accounting principle	$ 4.30	$ 2.31	$ 4.06
Cumulative effect of change in accounting principle	(0.09)		

Net income per share basic	$ 4.21	$ 2.31	$ 4.06
Net income per share fully diluted			
Income before cumulative effect of change in accounting principle	$ 4.29	$ 2.28	$ 4.00
Cumulative effect of change in accounting principle	(0.09)		
Net income per share fully diluted	$ 4.20	$ 2.28	$ 4.00
Weighted average shares outstanding basic	31,097	30,569	30,228
Weighted average shares outstanding fully diluted	31,213	30,878	30,645

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

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

	Common Stock		Additional Paid-In	Unearned	Retained Earnings	Accumulated Other Comprehensive Income	Total Stockholders
	Shares	$ Value	Capital	Compensation	(Deficit)	(Loss)	Equity
Balance January 1, 2001	**29,829,050**	**$ 298**	**$ 325,205**	**$**	**$ 71,239**	**$**	**$ 396,742**
Issuance of common stock, par value $0.01[1]	624,180	6	10,183				10,189
Issuance of restricted common stock, par value $0.01[2]	10,000	1	255	(256)			
Stock compensation expense amortization restricted stock				64			64
Tax benefit from exercise of non-qualified stock options			1,334				1,334
Comprehensive income:							
Net income					122,601		122,601
Other comprehensive income (as restated):							
Cumulative effect of accounting change for derivative instruments, net of tax benefit of $26,274						(48,795)	(48,795)
Derivative settlements reclassified to income, net of tax benefit of $4,524						(8,402)	(8,402)
Unrealized gain due to change in fair value of derivative instruments, net of tax expense of $49,618						92,148	92,148
Total comprehensive income							157,552
	30,463,230	**$ 305**	**$ 336,977**	**$ (192)**	**$ 193,840**	**$ 34,951**	**$ 565,881**

Balance December 31, 2001							
Issuance of common stock, value $0.01[1]	490,788	5	9,663				9,668
Contributed capital from KeySpan [3]			2,039				2,039
Stock compensation expense amortization of restricted stock				85			85
Tax benefit from exercise of non-qualified stock options			4,775				4,775
Comprehensive income:							
Net income					70,494		70,494
Other comprehensive income:							
Derivative settlements reclassified to income, net of tax benefit of $5,725						(10,633)	(10,633)
Unrealized loss due to change in fair value of derivative instruments, net of tax benefit of $26,665						(49,520)	(49,520)
Total comprehensive income							10,341
Balance December 31, 2002	**30,954,018**	**$ 310**	**$353,454**	**$ (107)**	**$264,334**	**$ (25,202)**	**$592,789**

(continued on next page)

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THE HOUSTON EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
AND COMPREHENSIVE INCOME
(continued)

	Common Stock		Additional Paid-In	Unearned	Retained Earnings	Accumulated Other Comprehensive Income	Total Stockholders
	Shares	$ Value	Capital	Compensation	(Deficit)	(Loss)	Equity
Balance December 31, 2002	**30,954,018**	**$ 310**	**$353,454**	**$ (107)**	**$264,334**	**$ (25,202)**	**$592,789**
Issuance of common stock, par value $0.01[1]	461,563	5	10,218				10,223
Issuance of restricted stock, par value $0.01[4]	22,000		812	(812)			
Issuance of common stock, par value $0.01[5]	3,000,000	30	79,170				79,200
Repurchase of common stock, par value $0.01[5]	(3,000,000)	(30)	(79,170)				(79,200)
Stock compensation expense amortization of restricted stock				111			111
Stock compensation expense stock options			903				903
Tax benefit from 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 benefit of $23,243						43,165	43,165
Unrealized loss due to change in fair value of derivative instruments, net of tax benefit of $23,745						(44,091)	(44,091)
Total comprehensive income							130,114
Balance December 31, 2003	**31,437,581**	**$ 315**	**$366,781**	**$ (808)**	**$395,374**	**$ (26,128)**	**$735,534**

(1) Common stock issued through the exercise of stock options. See Note 4 Stock Option Plans.

(2) Restricted stock issued to our President and Chief Executive Officer in April 2001 at $25.58 per share. See Note 6 Related Party Transactions *Transactions with our Executives*.

(3) Excess fair market value of oil and gas properties purchased from KeySpan in October 2002. See Note 6 Related Party Transactions *Acquisition of KeySpan Joint Venture Assets*

(4) Restricted stock issued pursuant to our Amended and Restated 2002 Long-Term Incentive Plan to non-employee directors and directors affiliated with KeySpan. We issued 20,000 shares (2,000 shares to each) on November 7, 2003 at $37.15 per share and 2,000 shares on December 3, 2003 at $34.79 per share. Restricted stock issued to directors vests at the earlier of retirement from our Board or at the ended of five years from date of grant. See Note 4 Stock Option Plans.

(5) Issuance of three million of our common shares to the public and concurrent repurchase of three million shares from KeySpan. See Note 3 Stockholders Equity.

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

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

	Years Ended December 31,		
	2003	**2002**	**2001**
Operating Activities:			
Net income	$ 131,040	$ 70,494	$ 122,601
Adjustments to reconcile net income to net cash provided by operating activities:			
Deferred income tax expense	59,668	39,860	67,643
Depreciation, depletion and amortization	197,530	171,610	128,736
Asset retirement accretion expense	3,668		
Writedown in carrying value of natural gas and oil properties			6,170
Stock compensation expense	1,014	85	64
Unrealized loss due to ineffectiveness of derivative instruments	1,950		
Debt extinguishment expense	1,626		
Cumulative effect of change in accounting principle	2,772		
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	(4,863)	(45,337)	70,119
(Increase) decrease in inventories	361	(283)	774
(Increase) decrease in prepayments and other	(3,622)	763	(1,046)
(Increase) decrease in other assets	(8,449)	4,427	(5,469)
Increase (decrease) in deferred liabilities	2,329	741	140
Increase (decrease) in accounts payable and accrued expenses	5,808	1,509	(31,700)
Net cash provided by operating activities	390,832	243,869	358,032
Investing Activities:			
Investment in property and equipment	(461,822)	(257,436)	(368,277)
Dispositions and other		5,311	
Net cash used in investing activities	(461,822)	(252,125)	(368,277)
Financing Activities:			
Proceeds from long-term borrowings	414,000	79,000	172,000
Repayments of long-term borrowings	(364,000)	(71,000)	(173,000)
Debt issuance costs for $175 million of 7% senior subordinated notes.	(4,695)		
Proceeds from issuance of common stock from exercise of stock options	10,223	9,668	10,189
Proceeds from issuance of common stock	79,200		
Repurchase of common stock	(79,200)		

Net cash provided by financing activities	55,528	17,668	9,189
Decrease in cash and cash equivalents	(15,462)	9,412	(1,056)
Cash and cash equivalents, beginning of year	18,031	8,619	9,675
Cash and cash equivalents, end of year	$ 2,569	$ 18,031	$ 8,619
Supplemental Information:			
Cash paid for interest	$ 18,403	$ 14,906	$ 14,777
Cash payment (refund) of federal and state income taxes	$ 14,800	$ (400)	$ 475

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

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THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 Summary of Organization and Significant Accounting Policies

Our Business

We are an independent natural gas and oil company engaged in the exploration, development, exploitation and acquisition of natural gas and oil reserves in North America. Natural gas is our primary focus. Our core areas of operations are South Texas, offshore in the shallow waters of the Gulf of Mexico, the Arkoma Basin of Oklahoma and Arkansas and the Appalachian Basin of West Virginia. During 2003, we began operations in the Rocky Mountain Region, with an initial focus in the Uinta Basin of northeastern Utah.

At December 31, 2003, our net proved reserves were 755 billion cubic feet equivalent or Bcfe, with a present value, discounted at 10% per annum, of cash flows before income taxes of $1.9 billion. Our reserves are fully engineered on an annual basis by independent petroleum engineers. Approximately 94% of our net proved reserves at December 31, 2003 were natural gas, approximately 68% of which were classified as proved developed. We operate approximately 85% of our producing wells.

We were founded in December 1985 as a Delaware corporation and began exploring for natural gas and oil on behalf of KeySpan Corporation. KeySpan, a member of the Standard & Poor s 500 Index, 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. As of December 31, 2003, THEC Holdings Corp., an indirect wholly owned subsidiary of KeySpan, owned approximately 55% of the outstanding shares of our common stock.

Principles of Consolidation

The consolidated financial statements include our accounts and the accounts of our wholly owned subsidiary, Seneca Upshur Petroleum Company, which is in the exploration and production business 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 and our full cost ceiling test limitation. See Note 12 Supplemental Information on Natural Gas and Oil Exploration, Development and Production Activities (Unaudited). 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 s reported amounts in order to conform with current year presentations.

Business Segment Information

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

Segment reporting is not applicable for us as each of our operating areas has similar economic characteristics and each meets the criteria for aggregation as defined in SFAS 131. All of our operations involve the exploration, development and production of natural gas and oil and all of our operations are located in the United States. We have a single, company-wide management team that administers all properties as a whole rather than as discrete operating segments. We track only

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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 using market prices as of the end of the period. Our production imbalances represented a net asset of $1.8 million and $33,000 at December 31, 2003 and 2002, respectively. The increase in our imbalance position at December 31, 2003 was due primarily to imbalances associated with Gulf of Mexico properties acquired in October 2003 from Transworld Exploration and Production Inc. See Note 10 Acquisitions *Transworld*.

Net Income Per Share

Basic earnings per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding during the period. No dilution for any potentially dilutive securities is included. Fully diluted earnings per share assumes the conversion of all potentially dilutive securities and is calculated by dividing net income by the sum of the weighted average number of shares of common stock outstanding plus all potentially dilutive securities.

	Years Ended December 31,		
	2003	**2002**	**2001**
Numerator:			
Income before cumulative effect of change in accounting principle	$133,812	$70,494	$122,601
Cumulative effect of change in accounting principle	(2,772)		
Net income	$131,040	$70,494	$122,601
Denominator:			
Weighted average shares outstanding	31,097	30,569	30,228
Add dilutive securities: Stock options	116	309	417

Total weighted average shares outstanding and dilutive securities	31,213	30,878	30,645
Earnings per share basic:			
Income before cumulative effect of change in accounting principle	$ 4.30	$ 2.31	$ 4.06
Cumulative effect of change in accounting principle	(0.09)		
Net income per share basic	$ 4.21	$ 2.31	$ 4.06
Earnings per share fully diluted:			
Income before cumulative effect of change in accounting principle	$ 4.29	$ 2.28	$ 4.00
Cumulative effect of change in accounting principle	(0.09)		
Net income per share fully diluted	$ 4.20	$ 2.28	$ 4.00

For the years ended December 31, 2003, 2002 and 2001, the calculation of shares outstanding for fully diluted earnings per share does not include the effect of outstanding stock options to purchase 1,865,313, 1,880,029 and 1,182,843 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 earnings per share.

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Comprehensive Income

The table below summarizes our Comprehensive Income for the years ended December 31, 2003, 2002 and 2001, respectively. Amounts are in thousands.

	Years Ended December 31,		
	2003	**2002**	**2001**
Net income	$131,040	$ 70,494	$122,601
Other comprehensive income, net of taxes:			
Net unrealized (loss) gain on fair value of derivative instruments	(926)	(60,153)	34,951
Comprehensive income	$130,114	$ 10,341	$157,552

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; plus,
- estimates for future development costs; 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 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 to hedge against the volatility of natural gas prices, and in accordance with Securities and Exchange Commission guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation.

In calculating our ceiling test at December 31, 2003 and 2002, we estimated, using a wellhead price of $5.79 per Mcf and $4.35 per Mcf, 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 $440.7 million (after tax) for 2003 and by $279.4 million (after tax) for 2002. No writedown was required.

In calculating the ceiling test at December 31, 2001, we estimated, using a wellhead price of $2.38 per Mcf, that our capitalized costs exceeded the ceiling limitation by $6.2 million ($4.0 million after tax). As a result, we reduced or wrote down the carrying value of our full cost pool and incurred a charge to earnings of $6.2 million ($4.0 million, after tax).

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Natural gas prices continue to be volatile and the risk that we will be required to writedown our full cost pool increases when natural gas prices are depressed or if we have significant downward revisions in our estimated proved reserves.

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, seismic data, wells and production facilities in-progress and wells pending determination together with interest costs capitalized for these projects. Unevaluated leasehold costs are transferred to the amortization base with the costs of drilling the related well 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 successful wells in-progress and wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. Costs of dry holes are transferred to the amortization base immediately upon determination that the well is unsuccessful. All items included in our unevaluated property balance are assessed on a quarterly basis for possible impairment or reduction in value. Of the $134.5 million of unevaluated property costs at December 31, 2003 that have been excluded from the amortization base, $78.9 million were incurred during 2003, $18.0 million were incurred in 2002, $21.4 million were incurred during 2001 and $ 16.2 were incurred prior to 2001. Of the $96.2 million of unevaluated property costs at December 31, 2002 that have been excluded from the amortization base, $38.8 million were incurred during 2002, $28.2 million were incurred in 2001, $6.9 million were incurred in 2000 and $22.3 million were incurred prior to 2000. We estimate these costs will be evaluated within a four-year period.

Classification of Intangible Leasehold Costs

SFAS 141, Business Combinations and SFAS 142, Goodwill and Intangible Assets, became effective on July 1, 2001 and January 1, 2002, respectively. These new standards emphasize a more precise evaluation of assets and their balance sheet classification as either tangible or intangible assets. We understand that the issue is under evaluation as to whether provisions of SFAS 141 and SFAS 142 may call for mineral rights held under lease or other contractual arrangements together with cash costs for the acquisition of natural gas and oil leasehold interests to be classified in the balance sheet as intangible assets. If these types of leasehold costs (both proved and unevaluated) are determined to be intangible assets, they would be classified separately from natural gas and oil properties as intangible assets on our balance sheets. This issue relates only to balance sheet classification and presentation and we do not believe it will not have an effect on cash flows or results of operations. At December 31, 2003, if we applied the interpretation currently under discussion, undeveloped leasehold costs of $117.1 million and developed leasehold costs of $221.3 million, net of accumulated amortization, would be reclassified from tangibles to intangibles, representing costs incurred since June 30, 2001, the effective date of SFAS 141. At December 31, 2002, we had undeveloped leasehold costs of $49.5 million and developed leasehold costs of $111.5 million, net of accumulated amortization that would be reclassified from tangibles to intangibles. Consistent with current industry practice, we will continue to classify our natural gas and oil leasehold costs as tangible natural gas and oil properties until the Emerging Issues Task Force issues further guidance.

Asset Retirement Obligations

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. For us, asset retirement obligations represent the systematic, monthly accretion and depreciation of future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and

other facilities. SFAS 143 requires that the fair value of a liability for an asset s retirement obligation be recorded in the period in which it is incurred 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, a gain or loss is recognized and an adjustment is made to the full cost pool. Under our previous accounting method, we included estimated future costs of abandonment and dismantlement in our full cost amortization base and amortized these costs as a component of our depletion expense.

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Pursuant to the January 1, 2003 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;
- increased our total liabilities by $57.2 million to record the asset retirement obligations (ARO);
- increased our assets by $42.5 million to add the asset retirement costs to the carrying amount of our natural gas and oil properties; and
- reduced our accumulated depreciation, depletion and amortization by $10.4 million for the amount of expense previously recognized.

Adopting SFAS 143 had no impact on our reported cash flows. The following table describes on a pro forma basis our asset retirement liability as if SFAS 143 had been adopted on January 1, 2002. The ARO liability in the table below includes amounts classified as both current and long-term at December 31st.

	Years Ended December 31,	
	2003	**2002**
ARO liability at January 1,	$57,197	$45,759
Additions from drilling	5,738	8,507
Additions from purchases	29,243	286
Deletions from abandonment	(160)	
Changes resulting from timing	(3,329)	
ARO accretion expense	3,668	2,645
ARO liability at December 31,	$92,357	$57,197

The following table describes the pro forma effect on net income and earnings per share for the years ended December 31, 2002 and 2001 as if SFAS 143 had been adopted on January 1, 2001.

	Years Ended December 31,		
	2003	**2002**	**2001**
Net income	$131,040	$68,774	$121,009
Earnings per share:			
Basic	$ 4.21	$ 2.25	$ 4.00
Fully diluted	4.20	2.23	3.95

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 accessible 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 90 days or less to be 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

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

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, we capitalize a portion of our general and administrative expenses that are directly identified with our acquisition, exploration and development activities. 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 2003, 2002 and 2001, of $12.9 million, $13.2 million and $12.8 million, respectively. We receive reimbursement for administrative and overhead expenses incurred on behalf of other working interest owners on properties we operate. These reimbursements totaling $1.6 million, $1.8 million and $1.2 million for the years ended December 31, 2002, 2001 and 2000, 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 and certain properties under development that are not currently being amortized. For the years ended December 31, 2003, 2002 and 2001, we capitalized interest costs of $7.3 million, $8.0 million and $12.0 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. Pursuant to our adoption of SFAS 133 on January 1, 2001, our derivative financial instruments are reported on the balance sheet at fair market value.

Derivative Instruments and Hedging Activities

To reduce our exposure to adverse price fluctuations, we generally hedge between 70 and 80 percent of our estimated future production volume. Our hedging policy does not permit us to hold derivative instruments for trading purposes. In our hedging program, we utilize a variety of derivative instruments, including swaps, collars and options. We generally place contracts with major financial institutions and other credit worthy counterparties. Although our hedging program protects 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 benefit of future price increases.

Our hedges are designated cash flow hedges and qualify for hedge accounting under SFAS 133, as amended, Accounting for Derivative Instruments and Hedging Activities 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 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. For 2003, our earnings include an unrealized loss of $1.9 million ($1.3 million net of tax) representing the ineffective portion of our derivative instruments that were not eligible for deferral. The ineffectiveness was a result of changes during the period in the price differentials between the index price of the derivative contract, which uses a New York Mercantile Exchange (NYMEX) index, and 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. See Note 7 Derivative Instruments, for a detailed listing of our derivative contracts and the fair market value of those contracts as of December 31, 2003 and 2002.

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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 reduces volatility in our reported results of operations, financial position and cash flows from period to period and lowers our overall business risk; but, as a result of our hedging activities we may be exposed to greater credit risk in the future.

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 now record as compensation expense the fair value of all stock options issued subsequent to January 1, 2003. No expense has been or will be recorded for grants made in previous years. For the year ended December 31, 2003, we incurred $0.9 million in compensation expense related to stock options issued during the year. 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 exercise price of a stock option is equal to the fair market value at the time of grant, no compensation expense is incurred. As a result, we incurred no compensation expense during 2002 and 2001 relating to stock options. See Note 4 Employee Benefit and Stock Plans *Fair Value of Employee Stock-Based Compensation* for a pro-forma disclosure of net income had stock options been accounted for based upon the fair value provisions of the SFAS 123.

New Accounting Pronouncements

In November 2002, FASB issued Financial Interpretation (FIN) No. 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others. FIN 45 requires certain guarantees to be recorded at fair value, which is different from the previous practice of recording a liability only when a loss is probable and reasonably estimable, as those terms are defined in SFAS 5, Accounting for Contingencies. FIN 45 has a dual effective date. The initial recognition and measurement provisions are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure requirements in the interpretation are effective for financial statements for interim or annual periods ending after December 15, 2002. As of our December 31, 2003 and December 31, 2002 balance sheet dates, we did not have any guarantees of indebtedness of others and as a result, our adoption of FIN 45 did not have an effect on our financial statements.

In January 2003, the FASB issued FIN No. 46, Consolidation of Variable Interest Entities An Interpretation of Accounting Research Bulletin 51. FIN 46 addresses consolidation by business enterprises of variable interest entities (VIEs) and the primary objective is to provide guidance on the identification of, and financial reporting for, entities over which control is achieved through means other than voting rights; such entities are known as VIEs. FIN 46 requires an entity to consolidate a VIE if the entity has a variable interest (or combination of variable interests) that will absorb a majority of the entity s expected losses if they occur, receive a majority of the entity s expected residual returns if they occur or both. This guidance applies immediately to VIEs created after January 31, 2003, and to VIEs in which an enterprise obtains an interest after that date. However, on October 8, 2003, the FASB decided to grant a broader deferral of the implementation of FIN 46. Pursuant to this deferral, public companies must complete their evaluations of VIEs that existed prior to February 1, 2003, and the consolidation of those for which they are the primary beneficiary for financial statements issued for the first period ending after December 15, 2003. For calendar year companies, consolidation of previously existing VIEs will be required in their December 31, 2003 financial statements. We have completed our

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evaluation of FIN 46 and because we do not believe that we have any VIEs there is no impact to our consolidated financial statements.

NOTE 2 Long-Term Debt and Notes

	Years Ended December 31,	
	2003	2002
	(in thousands)	
Senior Debt:		
Revolving bank credit facility, due July 15, 2005	$127,000	$152,000
Subordinated Debt:		
8-5/8% senior subordinated notes, due January 1, 2008		100,000
7% senior subordinated notes, due June 15, 2013	175,000	
Total long-term debt and notes	$302,000	$252,000

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, 2003, the quoted market value of our $175 million of 7% senior subordinated notes was 103% of the $175 million carrying value or $180.3 million. At December 31, 2002, the quoted market value of our $100 million of 8-5/8% senior subordinated notes was 103.8% of the $100 million carrying value or $103.8 million. At December 31, 2003, principle payments due over the next five-year period and thereafter are as follows.

	2004	2005	2006	2007	2008	2009
Revolving bank credit facility	$	$127,000	$	$	$	$
7% senior Subordinated Notes						175,000
Total maturities	$	$127,000	$	$	$	$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 Fleet National Bank as co-syndication agents

and BNP Paribas as documentation agent. The credit facility provides us with a commitment of $300 million which may be increased at our request and with prior approval from Wachovia to a maximum of $350 million by adding one or more lenders or by allowing one or more lenders to increase their commitments. The credit facility is subject to borrowing base limitations. Our current borrowing base is $300 million and is redetermined semi-annually, with the next redetermination scheduled for April 1, 2004. Up to $25 million of the borrowing base is available for the issuance of letters of credit. The credit facility matures July 15, 2005, is unsecured and with the exception of trade payables, ranks senior to our 7% senior subordinated notes. At December 31, 2003, we had $127 million in outstanding borrowings under the credit facility and $0.4 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% and 0.50%, depending on the amount of borrowings outstanding under the credit facility, or

- on fixed rate loans, a fixed rate equal to the sum of (a) a quoted LIBOR rate divided by one minus the average maximum rate during the interest period set for certain reserves of member banks of the Federal Reserve System in Dallas, Texas plus (b) a variable margin between 1.25% and 2.00%, 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.

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Our revolving bank credit facility contains customary negative covenants that place restrictions and limits on, among other things, the incurrence of debt, guaranties, 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 80% of our natural gas production during any 12-month period beginning July 15, 2002 through and including December 31, 2004, and not more than 70% of our natural gas production during any 12-month period, thereafter.

At December 31, 2003 and 2002, we were in compliance with all covenants.

Senior Subordinated Notes

7% Senior Subordinated Notes due June 15, 2013. 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 which 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, 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.

A change of control is:

- the direct or indirect acquisition by any person, other than KeySpan or its affiliates, of beneficial ownership of 35% or more of total voting power as long as KeySpan and its affiliates own less than the acquiring person;

- the sale, lease, transfer, conveyance or other disposition, other than by way of merger or consolidation, in one or a series of related transactions, of all or substantially all of our assets to a third party other than KeySpan or its affiliates;

- the adoption of a plan relating to our liquidation or dissolution; or

- if, during any period of two consecutive years, individuals who at the beginning of the period constituted our board of directors, including any new directors who were approved by a majority vote of directors then in office who were either directors at the beginning of the two-year period or who were previously so approved, cease for any reason to constitute a majority of the members then in office.

We received $170.3 million in net proceeds from the issuance of the $175 million of 7% senior subordinated notes. A portion of the net proceeds was used to repay the aggregate principal of $100 million on the 8-5/8% senior subordinated notes

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together with a premium of $4.3 million for early redemption. The remaining portion of the net proceeds was used to repay $60 million in outstanding borrowings on our revolving bank credit facility with the balance of approximately $6.1 million being applied to working capital, a portion of which was utilized in July 2003 to fund the payment of $4.6 million in accrued interest due on the $100 million 8 5/8% notes.

8 5/8% Senior Subordinated Notes due January 1, 2008. On July 11, 2003, we redeemed our $100 million 8 5/8% senior subordinated notes due January 1, 2008. The $100 million 8 5/8% senior subordinated notes were issued on March 2, 1998. The notes bore interest at a rate of 8 5/8% per annum with interest payable semi-annually on January 1 and July 1. The $100 million 8 5/8% notes were redeemable, at our option, in whole or in part, at any time on or after January 1, 2003 at a price equal to 100% of the principal amount plus accrued and unpaid interest, if any, plus a specified premium of 4.313%. The redemption and payment of the call premium were funded with a portion of the proceeds received from our June 10, 2003 issuance of the $175 million 7% senior subordinated notes due June 15, 2013. Upon closing of the $175 million 7% senior subordinated notes on June 10, 2003, the $100 million 8 5/8% notes were called. During the second quarter of 2003 and pursuant to the early redemption of the $100 million notes, we incurred debt extinguishment expenses totaling $5.9 million ($3.9 million net of tax) consisting of the call premium of $4.3 million together with a non-cash charge of $1.6 million for the write-off of the balance of the unamortized issue costs of the 8 5/8% notes. The debt extinguishment expenses of $5.9 million are included in the line item Other (Income) Expense on the Statement of Operations for the year ended December 31, 2003.

NOTE 3 Stockholders Equity

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 are obligated, at KeySpan s election, to facilitate KeySpan s sale of its shares of Houston Exploration 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. For the mutual convenience of the parties, we elected to complete KeySpan s sale through our pre-existing shelf registration statement rather than filing a separate, new registration statement for KeySpan. To accomplish the transaction, we simultaneously sold 3,000,000 newly issued shares of Houston Exploration stock in a public offering for net proceeds of $26.40 per share, or an aggregate $79.2 million, and bought a like number of KeySpan s shares of Houston Exploration 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. Our Board of Directors approved the transaction in principle and delegated to a special, independent committee of the Board plenary authority to negotiate the terms of, and finally approve or veto the transaction. In finally approving the terms of the stock purchase agreement, the independent committee determined that the agreement was consistent with our pre-existing obligations under our registration rights agreement and that issuing the shares under our existing shelf registration statement was in the best interests of our public stockholders to facilitate the prompt and orderly disposition of the shares. As a result of the transactions, KeySpan s interest in our outstanding shares decreased from 66% to 55%.

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 current 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, including the common stock of our company. 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 $1.3 million, $1.2 million and $0.7 million, respectively, for the years ended December 31, 2003, 2002 and 2001.

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Deferred Compensation Plan

In November 2002, we implemented 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 ($12,000 and $11,000 per year, respectively, for 2003 and 2002, with an additional $2,000 in 2003 and $1,000 in 2002 for employees 50 years of age or older) 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 2003 and 2002, we made matching contributions totaling $ 0.7 million and $0.5 million, respectively, to the deferred compensation plan. Employer contributions vest 20% per year and become fully vested after a five-year period. Notional accounts are maintained for each eligible employee to record salary deferrals, matching contributions and earnings and losses. 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, including our common stock. 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, 2003 and 2002, the fair market value of the assets held in the trust of $3.4 million and $1.0 million, respectively, 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.

Supplemental Executive Retirement Plan

We maintain an unfunded, non-qualified supplemental executive retirement plan. Currently, the only beneficiary is our former President and Chief Executive Officer, James G. Floyd. Upon Mr. Floyd s retirement March 31, 2001, he became entitled to receive payment of $100,000 per year for life. If Mr. Floyd predeceases his spouse, 50% of his retirement plan benefit will continue to be paid to his surviving spouse for her life. We incurred expenses of approximately $105,000, $105,000, and $113,000, respectively, during the years ended December 31, 2003, 2002 and 2001 related to this retirement plan. Annual expense incurred is greater than annual distribution due to the actuarial estimate of the future liability.

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 of approximately $4.8 million, $3.7 million and $6.8 million in 2003, 2002 and 2001.

Incentive Compensation Plan for Non-Employee Directors

We maintain an incentive compensation plan for non-employee, non-affiliated directors, which was adopted by our Board of Directors in October 1997 and under which participants may defer current compensation in the form of

phantom stock rights that are tied to the market price of the 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.

Stock and Option Plans

We have three stock options plans, together our (Stock Plans): (i) 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) 1999 Non-Qualified Stock Option Plan adopted by our Board of Directors in October 1999; and (iii) 2002 Long-Term Incentive Plan adopted in January 2002, approved by the stockholders in May 2002 and amended by our Board in October 2003. 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 one-fifth increments on each of the first five anniversaries of the grant date, with the exception of options granted to directors whose options vest immediately upon grant. All grants are made at the closing

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price of our common stock as reported on the NYSE on the date of grant. The 1996 and 2002 Plans allow for the grant of both incentive stock options and non-qualified stock options.

Common stock issued through the exercise of non-qualified 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 based 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 stock options during 2003, 2002 and 2001 resulted in a current tax benefit to us of approximately $1.4 million, $4.8 million and $1.3 million, respectively.

In addition to stock options, the 2002 Plan allows for the grant of up to 300,000 shares of restricted stock. Restricted stock carries voting and dividend rights; however, the sale or transfer of the shares is restricted. During 2003, we granted and issued 22,000 shares of restricted stock to non-employee directors and affiliated directors at an average grant price of $35.08 per share. The shares were issued as part of each director s annual compensation. The shares vest and become freely transferable at the earlier of retirement from our Board of Directors or at the end of five years from the date of grant. For 2003, we incurred $0.8 million to shareholders equity for the unearned compensation expense, the cost of which will be amortized, on a straight-line basis and recognized in earnings as compensation expense over the stock s five-year vesting period. During 2003, we recognized stock compensation expense of $26,000 related to these grants of restricted stock made pursuant to the 2002 Plan. In addition, during 2003, 2002 and 2001, we incurred stock compensation expense of $85,000, $85,000 and $64,000 for the amortization of restricted stock granted to our Chief Executive Officer upon his employment with our company in April 2001. See Note 6 Related Party Transaction Transactions with Executives.

The table below summarizes all of our Stock Plans as of December 31, 2003.

	2002 Plan	1999 Plan	1996 Plan	Total Plans
Options and restricted stock authorized	1,500,000	800,000	3,033,912	5,333,912
Options granted:				
Incentive stock options	47,686		1,032,302	1,079,988
Non-qualified stock options	1,152,489	806,606	2,009,910	3,969,005
Forfeitures	(10,750)	(24,343)	(11,877)	(46,970)
Total options	1,189,425	782,263	3,030,335	5,002,023
Restricted stock granted	22,000			22,000
Options and restricted stock available for grant	288,575	17,737	3,577	309,889
Total exercised and issued	39,250	230,740	2,196,874	2,466,864

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The table below sets forth a summary of activity for stock options during the respective years for all of our stock plans.

	Years Ended December 31,					
	2003		2002		2001	
	Shares	Price[1]	Shares	Price[1]	Shares	Price[1]
Options outstanding January 1	2,421,166	$27.50	2,164,448	$24.81	1,660,745	$17.99
Granted	606,725	34.86	753,559	30.14	1,129,871	30.15
Exercised	(461,563)	22.15	(490,788)	19.70	(624,180)	16.32
Forfeited	(31,169)	27.73	(6,053)	27.77	(1,988)	29.02
Options outstanding December 31	2,535,159	$30.23	2,421,166	$27.50	2,164,448	$24.81
Options exercisable December 31	838,568	$28.28	848,103	$25.12	940,929	$21.83
Options available for grant December 31	309,889		906,945		155,451	

[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, 2003.

Options Outstanding					Options Exercisable/Vested		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	31,200	1996	3 years	$15.60	31,200	$15.60	
$13.13 - $25.00	56,900	1997	4 years	20.32	56,900	20.32	
$15.75 - $23.38	54,364	1998	5 years	18.63	54,364	18.63	
$16.94 - $21.00	126,900	1999	6 years	18.96	97,320	19.02	29,580
$18.00 - $26.19	61,800	2000	7 years	23.30	36,000	24.26	25,800
$22.50 - $37.38	911,620	2001	8 years	31.08	415,554	33.21	496,066
$27.49 - $33.75	686,150	2002	9 years	30.14	124,230	30.03	561,920
$26.18 - $37.42	606,225	2003	10 years	34.86	23,000	35.06	583,225

2,535,159	$30.23	838,568	$28.28	1,696,591

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Fair Value of Employee Stock-Based Compensation

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 now record as compensation expense the fair value of all stock options issued subsequent to January 1, 2003. No expense has been or will be recorded for grants made in previous years. For the year ended December 31, 2003, we incurred $0.9 million in gross compensation expense related to stock options issued during the year of which $0.2 million was capitalized.

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 exercise price of a stock option is equal to the fair market value at the time of grant, no compensation expense is incurred. As a result, we incurred no compensation expense during 2002 and 2001 relating to stock options. Had stock options been accounted for using the fair value method as recommended in SFAS 123, compensation expense would have had the following pro forma effect on our net income and earnings per share for the years ended December 31, 2003, 2002 and 2001.

	Years Ended December 31,		
	2003	2002	2001
	(in thousands, except per share data)		
Net income as reported	$131,040	$70,494	$122,601
Add: Stock-based compensation expense included in Net income, net of tax	551	55	42
Less: Stock-based compensation expense determined using fair value method, net of tax	4,427	3,631	3,894
Net income pro forma	$127,164	$66,918	$118,749
Net income per share as reported	$ 4.21	$ 2.31	$ 4.06
Net income per share fully diluted as reported	4.20	2.28	4.00
Net income per share pro forma	4.09	$ 2.19	$ 3.93
Net income per share fully diluted pro forma	4.07	$ 2.17	$ 3.87

The effects of applying SFAS 123 in this pro forma disclosure may not be representative of future amounts. The weighted average fair values of options at their grant date during 2003, 2002 and 2001, where the exercise price equaled the market price on the grant date were $13.82, $14.08 and $13.45, respectively. The fair value of each option grant was estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions used for grants in 2003, 2002 and 2001:

	Years Ended December 31,		
	2003	2002	2001
Risk-free interest rate	4.02%	4.59%	5.80%
Expected years until exercise	5	5	5
Expected stock volatility	43%	46%	41%
Expected dividends			

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NOTE 5 Income Taxes

The components of the federal income tax provision (benefit) are:

	Years Ended December 31,		
	2003	2002	2001
		(in thousands)	
Current.	$12,519	$ (768)	$ (840)
Deferred	59,668	39,860	67,643
Total	$72,187	$39,092	$66,803

For 2002 and 2001, the credit in the current provision primarily represents Section 29 tax credits (see Note 6 Related Party Transactions *Section 29 Tax Credits*). At December 31, 2003, we had no net operating loss carryforwards remaining for federal income tax purposes. At of December 31, 2002, we had net operating loss carryforwards of approximately $47.5 million. 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 (benefit) to our income tax provision:

	Years Ended December 31,		
	2003	2002	2001
		(in thousands)	
Income before income taxes	$205,999	$109,586	$189,404
Statutory rate	35%	35%	35%
Income tax expense computed at statutory rate	72,100	38,355	66,291
Reconciling items:			
Section 29 tax credits and other tax credits[1]	58	(804)	512
Permanent differences	29		
Non-deductible compensation expense from 2001		1,541	
Tax provision	$ 72,187	$ 39,092	$ 66,803

(1) For 2003, excess deductions taken in 2002. For 2001, Section 29 tax credit amount includes an adjustment for an under-accrual of tax expense in 2000.

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Deferred Income Taxes

Deferred income taxes primarily represent the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of our deferred taxes are detailed in the table below. The change in the balance of our deferred income taxes for the current year comprised of deferred tax expense of $59.7 million, a tax benefit of $1.5 million pursuant to the cumulative effect of the change in accounting principle for the adoption of SFAS 143, a tax benefit of $1.4 million from the exercise of non-qualified employee stock options and a tax benefit of $1.2 million due to the change in the fair value of our derivative instruments that are deferred in accumulated other comprehensive income.

	Years Ended December 31,	
	2003	2002
	(in thousands)	
Deferred tax assets:		
Derivative instruments	$ 14,112	$ 13,570
Alternative minimum tax credit carryforwards	7,187	462
Net operating loss carryforwards		16,656
Total deferred tax assets	21,299	30,688
Deferred tax liabilities:		
Oil and gas property and equipment	252,440	206,651
Other comprehensive income derivative instruments	640	
Total deferred tax liabilities	253,080	206,651
Total deferred tax liability	$231,781	$175,963

NOTE 6 Related Party Transactions

Transactions With KeySpan

Issuance of 3,000,000 Shares to the Public and Concurrent Repurchase of 3,000,000 Shares from KeySpan (See Note 3 Stockholders Equity.)

KeySpan s Investment in Our Company

KeySpan has publicly announced that it considers its investment in Houston Exploration a non-core asset and that it continues to review strategic alternatives for its investment in our company including the sale of all or a portion of its investment in our common stock. At December 31, 2003, KeySpan held approximately 55% of the common shares outstanding or 17.4 million shares with a value of approximately $635 million.

Sale of Section 29 Tax Credits

In June 2003, we repurchased, for $2.6 million, certain interests in producing wells that were sold in January 1997 to a subsidiary of KeySpan under an agreement designed to monetize tax credits available under Section 29 of the Internal Revenue Code. Section 29 provides for a tax credit from non-conventional fuel sources such as oil produced from shale and tar sands and natural gas produced from geopressured brine, Devonian shale, coal seams and tight sands formations. The wells subject to the agreement are located in West Virginia, Oklahoma and East Texas and produce from formations that qualify for Section 29 tax credits. Pursuant to the agreement, KeySpan acquired an economic interest in wells that qualified for the tax credits and, in exchange, we:

- retained a volumetric production payment and a net profits interest of 100% in the properties;
- received a cash down payment of $1.4 million; and
- receive a quarterly payment of $0.75 for every dollar of tax credit utilized.

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During the term of the agreement, we managed and administered the daily operations of the properties in exchange for an annual management fee of $100,000. The agreement expired December 31, 2002 and as a result, we were required to repurchase the interests in the producing wells from KeySpan. Subsequent to the repurchase, ownership of the tax credits reverted back to us. The income statement effect, representing benefits received from Section 29 tax credits, was a benefit of $0.8 million both during 2002 and 2001, with no benefit during 2003.

Acquisition of KeySpan Joint Venture Assets

In October 2002, we purchased from KeySpan a portion of the assets developed under the joint exploration agreement with KeySpan Exploration & Production, LLC, a subsidiary of KeySpan (see below discussion of KeySpan Joint Venture). The acquisition consisted of interests averaging between 11.25% and 45% in 17 wells covering eight of the twelve blocks that were developed under the joint exploration agreement from 1999 through 2002. KeySpan retained a 45% interest in four blocks: South Timbalier 314 and 317 and Mustang Island 725 and 726 as these blocks were in various stages of development at the time of the acquisition. KeySpan committed to continued participation in the ongoing development of these blocks which included the completion of the platform and production facilities at South Timbalier 314/317 together with possible further developmental drilling. Both Houston Exploration and KeySpan farmed out their interest in Mustang Island 725/726 during 2003. At September 1, 2002, the effective date of the purchase, the estimated proved reserves associated with the interests acquired were 13.5 Bcfe. The $26.5 million purchase price was paid in cash and financed with borrowings under our revolving credit facility. Subsequent purchase price adjustments reduced our acquisition price by $1.2 million. The purchase price was adjusted for various closing items in the normal course of business, 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 (September 1, 2002) and the closing date (October 11, 2002). Our acquisition of the properties was accounted for as a transaction between entities under common control. As a result, the excess fair value of the properties acquired of $3.1 million ($2.0 million net of tax) was treated as a capital contribution from KeySpan and recorded as an increase to additional paid-in capital during the fourth quarter of 2002.

KeySpan Joint Venture

Effective January 1, 1999, we entered into a joint exploration agreement with KeySpan Exploration & Production, LLC, a subsidiary of KeySpan, to explore for natural gas and oil over an initial two-year term expiring December 31, 2000. Under the terms of the joint venture, we contributed all of our then undeveloped offshore acreage to the joint venture and we agreed that KeySpan would receive 45% of our working interest in all prospects drilled under the program. KeySpan paid 100% of actual intangible drilling costs for the joint venture up to a specified maximum. Further, KeySpan paid 51.75% of all additional intangible drilling costs incurred and we paid 48.25%. Revenues are shared 55% to Houston Exploration and 45% to KeySpan.

Effective December 31, 2000, KeySpan and Houston Exploration agreed to end the primary or exploratory term of the joint venture. As a result, KeySpan has not participated in any of our offshore exploration prospects unless the project involved the development or further exploitation of discoveries made during the initial term of the joint venture. During 2003, KeySpan spent approximately $9.5 million for capital costs associated with its working interests in properties developed under the joint venture. Costs incurred during 2003 were related to the installation of production facilities at South Timbalier 314/317, the completion of the initial two exploratory wells that were brought on-line during the first quarter of 2003 and participation in a third well, a development well on the property during the second quarter of 2003.

From the inception of the joint venture in January 1999 through December 31, 2003, we drilled a total of 29 wells: 21 exploratory wells of which 17 were successful and eight development wells of which seven were successful. KeySpan spent a total of $127.8 million, with $9.5 million, $19.0 million and $17.2 million, respectively being spent during 2003, 2002 and 2001.

Transactions With Our Executive Officers and Directors

Restricted Stock Grant to President and Chief Executive

On April 4, 2001, our Board of Directors appointed William G. Hargett to serve as our President and Chief Executive Officer and to serve on its Board of Directors. Pursuant to an employment agreement entered into on April 4, 2001 between us and Mr. Hargett, Mr. Hargett received a grant of 10,000 restricted shares of Houston Exploration common stock with a fair market value of approximately $256,000 at the time of grant. Until vested, the stock is restricted from transfer and

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subject to forfeiture in the event Mr. Hargett s employment is terminated. The shares vest, become nonforfeitable and freely transferable in equal one-third increments on each anniversary of the grant date. The cost of the restricted stock will be recognized in earnings as compensation expense over the stock s three-year vesting period. During 2003, 2002 and 2001 we recognized stock compensation expense of $85,000, $85,000 and $64,000, respectively related to this restricted stock grant.

Employment Contracts

We have entered into employment contracts with all nine of our executive officers. Contracts are initially set for a three year period and automatically extended one year on each anniversary unless either party gives notice within a specified number of days prior to the anniversary of the employment agreement. Executive officers receive annual salary and bonus payments pursuant to their employment contracts and if we terminate an employment agreement without cause or if the employee terminates an employment agreement with good reason, as defined in the employment agreements, we are obligated to pay the employee a lump-sum severance payment of 2.99 times the employee s then current annual rate of total compensation, as defined in the agreement, in addition to the continuation of certain insurance benefits for a specified time period.

Termination of Employment Agreements for Former Executives

During 2001, we recognized $5.2 million in general and administrative expenses pursuant to lump-sum payments made for the termination of employment contracts of our former President and Chief Executive Officer and Director, James G. Floyd, our Senior Vice President of Exploration and Production, Randall J. Fleming and our Chief Financial Officer, Thomas W. Powers. Each received lump sums of $2.3 million, $1.4 million and $1.5 million, respectively.

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 director of NATCO Group, a publicly traded oil field services and equipment company. During 2003, 2002 and 2001 we purchased services and supplies from NATCO of $1.1 million, $1.1 million and $0.9 million, respectively. Gordon F. Ahalt, also a member of our Board and Audit Committee serves as a director of Cal Dive International, a publicly traded offshore oil field service company that provides subsea construction, inspection, maintenance, repair and salvage services. During 2003 and 2002, we purchased services totaling $1.9 million and $0.3 million, respectively, from Cal Dive, with no purchases for 2001.

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NOTE 7 Derivative Instruments

As of December 31, 2003, we had entered into commodity price hedging contracts with respect to our production for 2004 and 2005 as listed in the tables below. Volumes and fair values are stated in thousands. The total estimated fair value of our natural gas and oil derivative instruments at December 31, 2003 was a negative $36.9 million ($27.4 million net of taxes of which $26.1 million was deferred in accumulated other comprehensive income and $1.3 million was recognized in current earnings as a reduction to natural gas and oil revenues.)

Natural Gas Hedges	Options - Puts		Fixed Price Swaps		Collars			Fair Value
Period	Volume (MMbtu)	NYMEX Contract Price	Volume (MMbtu)	NYMEX Contract Price	Volume (MMbtu)	NYMEX Contract Price		
						Avg Floor	Avg Ceiling	
January 2004	3,100	$5.000	1,240	$4.960	3,100	$3.750	$5.045	$ (4,901)
February 2004	2,900	5.000	1,160	4.960	2,900	3.750	5.045	(4,786)
March 2004	3,100	5.000	1,240	4.960	3,100	3.750	5.045	(4,210)
April 2004			1,200	4.960	6,000	4.125	6.023	(1,879)
May 2004			1,240	4.960	6,200	4.125	6.023	(1,277)
June 2004			1,200	4.960	6,000	4.125	6.023	(1,400)
July 2004			1,240	4.960	6,200	4.125	6.023	(1,631)
August 2004			1,240	4.960	6,200	4.125	6.023	(1,807)
September 2004			1,200	4.960	6,000	4.125	6.023	(1,699)
October 2004			1,240	4.960	6,200	4.125	6.023	(1,899)
November 2004			1,200	4.960	6,000	4.125	6.023	(2,794)
December 2004			1,240	4.960	6,200	4.125	6.023	(3,852)
January 2005			1,550	4.766	3,100	4.500	5.500	(3,074)
February 2005			1,450	4.766	2,800	4.500	5.500	(2,612)
March 2005			1,550	4.766	3.100	4.500	5.500	(2,064)
April 2005			1,500	4.766	3,000	4.500	5.500	343
May 2005			1,550	4.766	3,100	4.500	5.500	803
June 2005			1,500	4.766	3,000	4.500	5.500	754
July 2005			1,550	4.766	3,100	4.500	5.500	672
August 2005			1,550	4.766	3,100	4.500	5.500	605
September 2005			1,500	4.766	3,000	4.500	5.500	630
October 2005			1,550	4.766	3,100	4.500	5.500	500
November 2005			1,500	4.766	3,000	4.500	5.500	(254)
December 2005			1,550	4.766	3,100	4.500	5.500	(1,030)
								$(36,862)

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As of December 31, 2002, we had entered into commodity price hedging contracts with respect to our production for 2003 and 2004 as listed in the tables below. Volumes and fair values are stated in thousands. The total estimated fair value of our natural gas and oil derivative instruments at December 31, 2002 was a deferred loss of $38.8 million ($25.2 million net of taxes).

Natural Gas Hedges	Fixed Price Swaps		Collars			Fair Value
		NYMEX		NYMEX Contract Price		
Period	Volume (MMbtu)	Contract Price	Volume (MMbtu)	Avg Floor	Avg Ceiling	$ in thousands
January 2003	1,240	$3.194	4,495	$3.493	$4.954	$ (2,917)
February 2003	1,120	3.194	4,060	3.493	4.954	(2,908)
March 2003	1,240	3.194	4,495	3.493	4.954	(3,187)
April 2003	1,200	3.194	4,500	3.476	4.909	(2,542)
May 2003	1,240	3.194	4,650	3.476	4.909	(2,440)
June 2003	1,200	3.194	4,500	3.476	4.909	(2,446)
July 2003	1,240	3.194	4,650	3.476	4.909	(2,665)
August 2003	1,240	3.194	4,650	3.476	4.909	(2,754)
September 2003	1,200	3.194	4,500	3.476	4.909	(2,634)
October 2003	1,240	3.194	4,650	3.476	4.909	(2,782)
November 2003	1,200	3.194	4,500	3.476	4.909	(3,377)
December 2003	1,200	$3.194	4,650	3.476	4.909	(4,209)
January 2004			1,550	3.500	4.750	(916)
February 2004			1,400	3.500	4.750	(759)
March 2004			1,550	3.500	4.750	(597)
April 2004			1,500	3.500	4.750	(217)
May 2004			1,550	3.500	4.750	(103)
June 2004			1,500	3.500	4.750	(71)
July 2004			1,550	3.500	4.750	(83)
August 2004			1,550	3.500	4.750	(94)
September 2004			1,500	3.500	4.750	(72)
October 2004			1,550	3.500	4.750	(97)
November 2004			1,500	3.500	4.750	(277)
December 2004			1,550	3.493	4.750	(480)
						$(38,627)

Oil Hedges	Fixed Price Swaps	Collars	Fair Value

Period	Volume (MBbl)	NYMEX Contract Price	Volume (MBbl)	NYMEX Contract Price Avg Floor	NYMEX Contract Price Avg Ceiling	$ in thousands
January 2003	31	$28.50				$ (77)
February 2003	28	28.50				(48)
March 2003	31	28.50				(20)
						$(145)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For natural gas, transactions are settled based upon the NYMEX price on the final trading day of the month. For oil, our swaps are settled against the average NYMEX price of oil for the calendar month rather than the last day of the month. 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.

These hedging transactions are settled based upon the average of the reported settlement prices on the NYMEX for the last three trading days of a particular contract month or 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, 2003, 2002 and 2001 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.

	For the Year Ended December 31,		
Major Purchaser	**2003**	**2002**	**2001**
Anadarko Petroleum Corporation	11.7%	12.6%	7.3%
ConocoPhillips	18.4%	14.9%	4.0%
KinderMorgan	11.4%	9.8%	5.0%
Dynegy, Inc.		5.5%	16.4%
Adams Resources and Energy, Inc.	4.5%	8.2%	12.5%
El Paso Corporation	0.8%	4.8%	9.5%

Note: Amounts disclosed that are less than 10% are presented for information and comparison purposes only.

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, 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 year ended December 31, 2003, we recognized as other income refunds of prior period severance tax payments of $21.6 million ($14.0 million net of tax). For the year ended December 31, 2002, we recognized a total of $10.4 million ($6.8 million net of tax), of which $1.3 million related to refund of 2002 severance tax expense and $9.1 related to refunds of prior period expense. At December 31, 2003 and 2002, our current receivables include $12.9 million and $14.8 million, respectively, in gross refunds of which we estimate, approximately 70%, or $9.0 million and $10.4 million, respectively, relate to our net revenue interest. We expect to collect our current receivable prior to the end of the third quarter of 2004. 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. For future periods, we do not expect to recognize as income future refunds of prior

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years severance tax in excess of $1 million.

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 (telephones, copiers and faxes). The terms of these agreements have various expiration dates from 2004 through 2009. Rental expense related to these leases was $1.3 million, $1.2 million and $0.6 million, respectively, for the years ended December 31, 2003, 2002 and 2001. At December 31, 2003, our total commitment under these non-cancelable operating leases was $8.3 million. Minimum rental commitments under the terms of our operating leases are as follows (in thousands):

Year Ended December 31,	Minimum Payments
2004	$1,470
2005	1,371
2006	1,478
2007	1,525
2008	1,579
2009 and thereafter	920
Total	$8,343

NOTE 10 Acquisitions

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 are 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 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 are an estimated 88.5 Bcfe, of which 75% is natural gas. Current production is from 11 fields and is estimated at approximately 35 MMcfe per day, net to our interest. We operate properties representing 97% of the proved reserves with an average working interest of 65%.

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*Acquisition of KeySpan Joint Venture Assets (*See Note 6 Related Party Transaction *Transactions with KeySpan).*

Burlington Acquisition

On May 30, 2002, we completed the purchase of natural gas and oil producing properties and associated gathering pipelines, together with undeveloped acreage, from Burlington Resources Inc. located in the Webb, Jim Hogg, Wharton and Calhoun counties of South Texas. The properties purchased cover approximately 24,800 gross (10,800 net) acres located in the Northeast Thompsonville, South Laredo, McFarlan and Maude Traylor Fields. The properties purchased represent interests in approximately 145 producing wells and total proved reserves of 42 Bcfe as of January 1, 2002, the effective date of the transaction. Our average working interest is 35% and we are the operator of approximately 23% of the producing wells acquired. The $44.5 million purchase price, which is net of a purchase price adjustment of $3.9 million, was financed by borrowings under our revolving bank credit facility. The purchase price was reduced for various closing items in the normal course of business, 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 (January 1, 2002) and the closing date (May 30, 2002).

On July 16, 2002, we sold those interests acquired from Burlington in the McFarlan and Maude Traylor Fields for approximately $5.0 million, which was net of a purchase price adjustment of $1.1 million. The effective date of this transaction was January 1, 2002. These two fields, located in Wharton and Calhoun counties, respectively, are outside our current area of focus in South Texas. The sale represented interests in 22 producing wells with reserves of approximately 5 Bcfe. Proceeds from the sale were used to repay borrowings under our revolving bank credit facility.

We retained the Northeast Thompsonville Field, located in Jim Hogg County, and the South Laredo Field, located in Webb County. The Northeast Thompsonville Field has 10 wells producing from the Wilcox formation, all of which we operate, and representing approximately 70% of the proved reserves and 75% of the current production associated with the acquisition from Burlington. The South Laredo Field, located in Webb County and in the Lobo Trend, contains 113 wells, all operated by a third party.

Conoco Acquisition

On December 31, 2001, we completed the purchase of certain natural gas and oil properties and associated gathering pipelines and equipment, together with developed and undeveloped acreage, located in Webb and Zapata counties of South Texas, from Conoco Inc. The $69 million purchase price was paid in cash and financed by borrowings under our revolving bank credit facility. The properties purchased cover approximately 25,274 gross (16,885 net) acres located in the Alexander, Haynes, Hubbard and South Trevino Fields, which are in close proximity to our existing operations in the Charco Field, and represent interests in approximately 159 producing wells. We operate approximately 95% of the producing wells acquired and our average working interest is 87%. Total proved reserves associated with the interests acquired were 85 Bcfe, as of the October 1, 2001, the effective date of the transaction.

NOTE 11 Subsequent Event

Sale of Onshore South Louisiana Properties

On February 4, 2003, 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 $2.2 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, January 1, 2004, and the closing date, February 4, 2003. The net proceeds from the sale of $12.8 million were used to repay borrowings under our revolving bank credit facility.

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NOTE 13 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. Our natural gas and oil reserves were estimated by independent reserve engineers.

Capitalized Costs of Natural Gas and Oil Properties

	As of December 31,		
	2003	2002	2001
	(in thousands)		
Unevaluated properties, not subject to amortization	$ 134,491	$ 96,192	$ 177,987
Properties subject to amortization	2,324,011	1,828,160	1,493,293
Capitalized costs	2,458,502	1,924,352	1,671,280
Accumulated depreciation, depletion and amortization	(1,092,073)	(906,089)	(735,257)
Net capitalized costs	$ 1,366,429	$1,018,263	$ 936,023

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, 2003, 2002 and 2001 include interest expense and general and administrative costs related to acquisition, exploration and development of natural gas and oil properties of $20.2 million, $21.1 million and $24.9 million, respectively.

	As of December 31,		
	2003	2002	2001
	(in thousands)		
Property acquisition and leasehold costs			
Unevaluated[1]	$ 61,224	$ 14,600	$ 31,711

Proved	170,272	89,873	85,367
Exploration costs	66,259	26,563	72,056
Development costs	162,235	122,036	177,256
	459,990	253,072	366,390
Asset retirement obligation[2]	31,652		
Total costs incurred	$491,642	$253,072	$366,390

(1) Unevaluated amounts represent costs we incurred during the year and excluded from the amortization base until proved reserves are established or impairment is determined. We estimate that these costs will be evaluated within four years.

(2) Asset retirement obligation costs incurred during 2003 exclude the cumulative effect of the change for prior years of $42.5 million pursuant to our adoption of SFAS 143 on January 1, 2003.

During the years ended December 2003, 2002 and 2001, we spent $46.0 million, $11.0 million and $19.9 million, respectively, to develop our proved undeveloped reserves. At December 31, 2003, 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 $96.3 million, $126.4 million, and $10.5 million, respectively, for 2004, 2005 and 2006.

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

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.

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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 and is unaudited.

	As of December 31,		
	2003	2002	2001
		(in thousands)	
Future cash inflows	$4,335,669	$2,845,768	$1,471,557
Future production costs	(764,373)	(486,399)	(302,145)
Future development costs	(369,121)	(241,876)	(189,480)
Future income taxes	(850,264)	(542,782)	(211,191)
Future net cash flows	2,351,911	1,574,711	768,741
10% annual discount for estimated timing of cash flows	(847,505)	(516,647)	(217,216)
Standardized measure of discounted future net cash flows	$1,504,406	$1,058,064	$ 551,525

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

	As of December 31,		
	2003	2002	2001
		(in thousands)	
Beginning of the year	$1,058,064	$ 551,525	$ 2,064,027
Revisions to previous estimates:			
Changes in prices	459,373	629,542	(2,088,576)
Changes in quantities	(123,954)	(36,368)	(52,928)
Changes in future development costs	(13,029)	(1,970)	(18,001)
Development costs incurred during the period	72,717	23,393	65,940
Extensions and discoveries, net of related costs	434,311	242,055	116,710
Sales of natural gas and oil, net of production costs	(486,382)	(275,157)	(343,181)
Accretion of discount	136,492	64,858	279,648

Net change in income taxes	(245,151)	(209,807)	635,400
Purchase of reserves in place	254,030	99,741	51,674
Sale of reserves in place		(170)	(133)
Production timing and other	(42,065)	(29,578)	(159,055)
End of year	$1,504,406	$1,058,064	$ 551,525

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Estimated Net Quantities of Natural Gas and Oil Reserves

The following table sets forth our net 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, 2003, 2002 and 2001. All amounts are unaudited.

	Natural Gas (MMcf)			Crude Oil, Liquids and Condensate (MBbls)		
	2003	2002	2001	2003	2002	2001
Beginning of the year reserves	610,409	568,208	529,518	6,533	6,605	5,352
Revisions of previous estimates	(30,573)	(14,863)	(41,914)	(1,615)	(26)	(174)
Extensions and discoveries	140,632	105,798	83,551	117	342	1,800
Production	(99,965)	(97,368)	(87,095)	(1,307)	(859)	(459)
Purchase of reserves in place	89,380	48,777	84,148	3,753	483	115
Sales of reserves in place		(143)			(12)	(29)
End of year reserves	709,883	610,409	568,208	7,481	6,533	6,605
Proved developed reserves:						
Beginning of year	435,629	438,538	420,733	2,413	2,123	1,810
End of year	487,867	435,629	438,538	4,073	2,413	2,123

	Natural Gas Equivalents (MMcfe)		
	2003	2002	2001
Beginning of year reserves	649,607	607,838	561,630
Revisions of previous estimates	(40,263)	(15,019)	(42,958)
Extensions and discoveries	141,334	107,850	94,351
Production	(107,807)	(102,522)	(89,849)
Purchase of reserves in place	111,898	51,675	84,838
Sales of reserves in place		(215)	(174)
End of year reserves	754,769	649,607	607,838

Proved developed reserves:			
Beginning of year	450,107	451,276	431,593
End of year	512,305	450,107	451,276

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 13 Quarterly Financial Information (Unaudited)

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(in thousands, except per share data)			
2003				
Total revenues	$129,003	$120,632	$118,887	$124,230
Total operating expenses	68,807	70,341	69,856	85,153
Income from operations	60,196	50,291	49,031	39,077
Income before cumulative effect of change in accounting principle	44,469	28,923	34,719	25,701
Cumulative effect of change in accounting principle	(2,772)			
Net income	41,697	28,923	34,719	25,701
Net income per share basic:				
Income before cumulative effect of change in accounting principle	$ 1.44	$ 0.93	$ 1.12	$ 0.82
Cumulative effect of change in accounting principle	(0.09)			
Net income per share basic[1]	$ 1.35	$ 0.93	$ 1.12	$ 0.82
Net income per share fully diluted:				
Income before cumulative effect of change in accounting principle	$ 1.43	$ 0.93	$ 1.11	$ 0.82
Cumulative effect of change in accounting principle	(0.09)			
Net income per share fully diluted[1]	$ 1.34	$ 0.93	$ 1.11	$ 0.82
2002				
Total revenues	$ 74,816	$ 85,955	$ 84,205	$100,405
Total operating expenses	54,425	57,436	58,745	66,861
Income from operations	20,391	28,519	25,460	33,544
Net income	12,534	17,654	15,272	25,034
Net income per share basic[1]	$ 0.41	$ 0.58	$ 0.50	$ 0.81
Net income per share fully diluted[1]	$ 0.41	$ 0.57	$ 0.50	$ 0.81

(1)

Quarterly earnings per share is based on the weighted average number of shares outstanding during the quarter. Because of the increase in the number of shares outstanding during the quarters due to the exercise of stock options, the sum of quarterly earnings per share may not equal earnings per share for the year.

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INDEX TO EXHIBITS

EXHIBITS	DESCRIPTION
3.1	Restated Certificate of Incorporation (filed as Exhibit 3.1 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 1997 (File No. 001-11899) and incorporated by reference).
3.2	Restated Bylaws (filed as Exhibit 3.2 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 1997 (File No. 001-11899) and incorporated by reference).
4.1	Indenture, dated as of June 10, 2003, between The Houston Exploration Company and the Bank of New York, as Trustee, with respect to the 7% Senior Subordinated Notes due 2013. (Exhibit 4.2 to our Registration Statement on Form S-4 (Registration No. 333-106836) and incorporated by reference).
10.1	Registration Rights Agreement dated as of July 2, 1996 between The Houston Exploration Company and THEC Holdings Corp. (filed as Exhibit 10.13 to our Registration Statement on Form S-1 (Registration No. 333-4437) and incorporated by reference).
10.2	Registration Rights Agreement dated as of June 5, 2003, among The Houston Exploration Company and Wachovia Securities, Inc., Lehman Brothers Inc., BNP Paribas Securities Corp., Fleet Securities, Inc. and Scotia Capital (USA) Inc., as Initial Purchasers. (Exhibit 4.5 to our Registration Statement on Form S-4 (Registration No. 333-106836) and incorporated by reference).
10.3	Exploration Agreement between The Houston Exploration Company and KeySpan Exploration and Production, L.L.C., dated March 15, 1999, (filed as Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 1999 (File No. 001-11899) and incorporated by reference).
10.4	First Amendment to the Exploration Agreement between The Houston Exploration Company and KeySpan Exploration and Production, L.L.C. dated November 3, 1999 (filed as Exhibit 10.19 to our Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 001-11899) and incorporated by reference).
10.5	Restated Exploration Agreement dated June 30, 2000 between The Houston Exploration Company and KeySpan Exploration and Production, L.L.C (filed as Exhibit 10.1 to our Quarterly on Form 10-Q for the quarter ended September 30, 2000 File No. 001-11899) and incorporated by reference).
10.6(2)	Supplemental Executive Pension Plan (filed as Exhibit 10.23 to our Registration Statement on Form S-1 (Registration No. 333-4437) and incorporated by reference).
10.7(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).

10.8[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).
10.9[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).
10.10[2]	Executive Deferred Compensation Plan dated January 1, 2002 (incorporated by reference from Exhibit 10.28 to the original filing on February 20, 2003 of our Annual Report on Form 10-K for the year ended December 30, 2002 File No. 001-11899).
10.11[2]	2002 Long-Term Incentive Plan effective May 17, 2002 (filed as Exhibit 1 to our Definitive Proxy Statement on Schedule 14A (File No. 001-11899) and incorporated by reference).
10.12[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).
10.13[2]	Employment Agreement dated July 2, 1996 between The Houston Exploration Company and James F. Westmoreland (filed as Exhibit 10.11 to our Registration Statement on Form S-1 (Registration No. 333-4437) and incorporated by reference).
10.14[2]	First Amendment to Employment Agreement dated April 26, 2001 between The Houston Exploration Company and James F. Westmoreland (filed as Exhibit 10.5 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2001 File No. 001-11899).

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INDEX TO EXHIBITS

EXHIBITS	DESCRIPTION
10.15[2]	Second Amendment to Employment Agreement dated January 10, 2003 between The Houston Exploration Company and James F. Westmoreland (incorporated by reference from Exhibit 10.27 to the original filing on February 20, 2003 of our Annual Report on Form 10-K for the year ended December 30, 2002 File No. 001-11899).
10.16[2]	Employment Agreement dated May 1, 1998 between The Houston Exploration Company and Thomas E. Schwartz (filed as Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 1998 (File No. 001-11899) and incorporated by reference).
10.17[2]	First Amendment to Employment Agreement dated April 26, 2001 between The Houston Exploration Company and Thomas W. Schwartz (filed as Exhibit 10.4 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2001 File No. 001-11899)
10.18[2]	Employment Agreement, dated September 19, 1996, between The Houston Exploration Company and Charles W. Adcock (filed as Exhibit 10.26 to our Annual Report on Form 10-K for the year ended December 31, 1996 (File No. 001-11899) and incorporated by reference).
10.19[2]	First Amendment to Employment Agreement dated April 26, 2001 between The Houston Exploration Company and Charles W. Adcock (filed as Exhibit 10.3 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2001 File No. 001-11899).
10.20(2)	Employment Agreement dated April 4, 2001 between The Houston Exploration Company and William G. Hargett (filed as Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2001 File No. 001-11899).
10.21[2]	First Amendment to Employment Agreement between The Houston Exploration Company and William G. Hargett dated May 17, 2002 (filed as Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 File No. 001-11899).
10.22[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).
10.23[2]	Employment Agreement dated October 22, 2001 between The Houston Exploration Company and Steven L. Mueller (filed as Exhibit 10.32 to our Annual Report on Form 10-K for the year ended December 31, 2001 File No. 001-11899).
10.24[2]	Employment Agreement dated March 1, 2002 between The Houston Exploration Company and Roger B. Rice (filed as Exhibit 10.33 to our Annual Report on Form 10-K for the year ended December 30, 2001 File No. 001-11899).
10.25[2]	Employment Agreement dated November 18, 2002 between The Houston Exploration Company and John H. Karnes (incorporated by reference from Exhibit 10.26 to the

	original filing on February 20, 2003 of our Annual Report on Form 10-K for the year ended December 30, 2002 File No. 001-11899).
10.26[(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).
10.27	Revolving Credit Facility between The Houston Exploration Company and Wachovia Bank, National Association, as issuing bank and administrative agent, Bank of Nova Scotia and Fleet National Bank as co-syndication agents and BNP Paribas as documentation agent dated July 15, 2002 (filed as Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 File No. 001-11899).
10.28	First Amendment to Credit Agreement among The Houston Exploration Company, the lenders Wachovia Bank, National Association, as issuing bank and as administrative agent, The Bank of Nova Scotia and Fleet National Bank, as co-syndication agents; and BNP Paribas, as documentation agent, effective June 5, 2003 (filed as Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 File No. 001-11899).
10.29	Second Amendment to Credit Agreement among The Houston Exploration Company, the lenders named therein, Wachovia Bank, National Association, as issuing bank and as administrative agent, The Bank of Nova Scotia and Fleet National Bank, as co-syndication agents; and BNP Paribas, as documentation agent, effective September 3, 2003 (filed as Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 2003 File No. 001-11899).
10.30	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 and incorporated by reference.
10.31[(1)(2)]	Amended and Restated 2002 Long-Term Incentive Plan effective May 17, 2002, adopted October 26, 2003.

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EXHIBITS	DESCRIPTION
12.1[(1)]	Computation of ratio of earnings to fixed charges.
21.1[(1)]	Subsidiary of Houston Exploration.
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 John H. Karnes, 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 John H. Karnes, 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.