HOUSTON EXPLORATION CO
Form 10-K/A
November 13, 2003

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

FORM 10-K/A
AMENDMENT NO. 1
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2002
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM __________ TO __________

COMMISSION FILE NO. 001-11899

THE HOUSTON EXPLORATION COMPANY
(EXACT NAME OF REGISTRANT AS SPECIFIED IN ITS CHARTER)

DELAWARE (STATE OR OTHER JURISDICTION OF INCORPORATION OR ORGANIZATION)	22-2674487 (IRS EMPLOYER IDENTIFICATION NO.)
1100 LOUISIANA, SUITE 2000 HOUSTON, TEXAS (ADDRESS OF PRINCIPAL EXECUTIVE OFFICES)	77002-5215 (ZIP CODE)

(713) 830-6800
(REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE)

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

TITLE OF EACH CLASS	NAME OF EACH EXCHANGE ON WHICH REGISTERED
Common Stock, $.01 par value	New York Stock Exchange
8 3/8% Senior Subordinated Notes due 2008	

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 [X] No [ ]

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/A or any amendment to this Form 10-K. [X]

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

The aggregate market value of the voting stock held by non-affiliates of the registrant was approximately $294,266,721 as of June 28, 2002, based on the closing sales price of the registrant's common stock on the New York Stock Exchange on such date of $29.00 per share. 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 February 20, 2003, 30,961,418 shares of common stock were outstanding.

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All of the estimates and assumptions contained in this Annual Report and in the documents we have incorporated by reference into this Annual Report constitute forward looking statements as that term is defined in Section 27A of the Securities Act of 1993 and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements generally are accompanied by words such as "anticipate," "believe," "expect," "estimate," "project" or similar 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 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 assumptions, our expectations may not occur and we cannot guarantee that the anticipated future results will be achieved. A number of factors could cause our actual future results to differ materially from the anticipated future results expressed in this Annual Report. 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 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.

In this Annual Report, unless the context requires otherwise, when we refer to "we", "us" or "our", we are describing The Houston Exploration Company and its subsidiaries on a consolidated basis. Further, if you are not familiar with the oil and gas terms used in this report please refer to the explanations of the terms under the caption "Glossary of Oil and Gas Terms" included on pages G-1 through G-3. 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 AND ORGANIZATION

We are an independent natural gas and oil company engaged in the exploration, development, exploitation and acquisition of domestic natural gas and oil properties. Our operations are primarily focused in South Texas, offshore in the Gulf of Mexico and in the Arkoma Basin of Oklahoma and Arkansas.

At December 31, 2002, our net proved reserves were 650 billion cubic feet equivalent or Bcfe, with a present value, discounted at 10% per annum, of cash flows before income taxes of $1.3 billion. Our reserves are fully engineered on an annual basis by independent petroleum engineers. Our focus is natural gas. Approximately 94% of our net proved reserves at December 31, 2002 were natural gas, approximately 69% of which were classified as proved developed. We operate approximately 85% of our properties.

We began exploring for natural gas and oil in December 1985 on behalf of The Brooklyn Union Gas Company. Brooklyn Union is an indirect wholly owned subsidiary 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, 2002, THEC Holdings Corp., an indirect wholly owned subsidiary of KeySpan, owned approximately 66% of the outstanding shares of our common stock.

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

2002 OPERATING HIGHLIGHTS

During the year ended December 31, 2002 we drilled a total of 97 wells of which 84 were successful reflecting a success rate of 86%. We produced a total of 103 billion cubic feet equivalent, or Bcfe, and increased our average daily production by 14% to 281 million cubic feet equivalent, or MMcfe, per day. We replaced 141% of our production by adding 145 Bcfe in net proved reserves. We generated $282 million in cash flows from operations before adjustments for changes in current assets and liabilities and invested a net $253 million in natural gas and oil properties, including $65 million for producing properties acquired in South Texas and the Gulf of Mexico.

INVESTMENT STRATEGY

We strive to maximize shareholder value while maintaining our financial flexibility by pursuing a dynamic 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 activities intended to generate stable and growing cash flows from which we can fund future expansion.

- 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 disciplined investments in acquisitions of new properties that 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. 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. We prefer to operate our properties rather than owning non-operating interests. Operating our properties 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 in the performance of duties, 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 properties, which has contributed to our historically low operating costs.

- 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, 2002, 91% of our reserves were located in our three core areas: South Texas, the Gulf of Mexico and the Arkoma Basin of Oklahoma and Arkansas.

- 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. Our hedges typically take the form of fixed price swaps and no-cost collars under which we are assured a minimum floor price for our production and enjoy the benefit of price increases up to a predetermined ceiling price. Depending on the outlook for future prices and the state of the options markets, we may hedge up to 70% of our production for up to two years or more.

2002 OPERATIONS REVIEW

The table below summarizes certain data for our core operating areas for the year ended December 31, 2002. More detailed information regarding natural gas and oil production and average prices received in 2002, 2001 and 2000 is available in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations." See Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for more information regarding our hedging practices. In addition, for more information regarding reserve quantities, capitalized costs and estimated future revenues and expenses relating to our natural gas and oil properties, see "Notes to Consolidated Financial Statements - Note 12 - Supplemental Information On Natural Gas and Oil Exploration, Development and Production Activities (Unaudited)."

ACTIVITY AND BALANCES AS OF OR FOR THE YEAR ENDED DECEMBER 3

AREA	AVERAGE DAILY PRODUCTION	TOTAL PRODUCTION	NATURAL GAS AND OIL REVENUES	TOTAL PROVED RESERVES	PERCENTAGE TOTAL PROVED RESERVES
	(MMcfe/d)	(MMcfe)	($ Thousands)	(MMcfe)	
South Texas	123	44,720	$ 141,220	298,926	46%
Gulf of Mexico	126	46,226	149,810	197,856	31%
Arkoma Basin	20	7,432	21,750	93,081	14%
Other Onshore	12	4,144	15,157	59,744	9%
Total	281	102,522	$ 327,937	649,607	100%

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 North East Thompsonville Field in Jim Hogg County. We own interests in 562 producing wells, 450 of which we operate.

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. We hold interests 86 blocks in federal and state waters, of which 42 are developed. We operate 29 of our developed blocks, which accounted for approximately 75% of our offshore production during 2002. We have a total of 37 platforms and production cassions of which we operate 27.

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 Panola Fields located in Latimer County, Oklahoma. We own working interests in 252 producing natural gas wells, 131of which we operate.

Other Onshore. Other Onshore properties are concentrated in three areas: South Louisiana; West Virginia; and East Texas. On a combined basis, we own working interests in 708 producing wells, 653 of which we operate.

ACQUISITIONS

KeySpan Joint Venture Assets. On October 11, 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. 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. The interests purchased were in the following blocks: Vermilion 408, East Cameron 81 and 84, High Island 115, Galveston Island 190 and 389, Matagorda Island 704 and North Padre Island 883. KeySpan has retained its 45% interest in four blocks: South Timbalier 314 and 317 and Mustang Island 725 and 726, as these blocks are in various stages of development. KeySpan has committed to continued participation in the ongoing development of these blocks including the completion of the platform and production facilities at South Timbalier 314/317 together with possible further developmental drilling at both South Timbalier 314/317 and Mustang Island 725/726. As of 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 bank credit facility. Subsequent purchase price adjustments reduced our acquisition price by $1.2 million. The purchase price was adjusted 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 (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.

Burlington Acquisition. On May 30, 2002, we completed the purchase of natural gas and oil producing properties, together with undeveloped acreage, from Burlington Resources Inc. located in the Webb and Jim Hogg Counties of South Texas. The properties purchased cover approximately 24,800 gross (10,800 net) acres located in the North East Thompsonville and South Laredo Fields. The properties purchased represent interests in approximately 123 producing wells and total proved reserves of 37 Bcfe as of January 1, 2002, the effective date of the transaction. The North East Thompsonville Field has 10 wells producing from the Wilcox formation, all of which we operate. This field represents approximately 70% of the proved reserves and 75% of the current production associated with the acquisition. The South Laredo Field, located in Webb County and in the Lobo Trend, contains 113 wells, all operated by a third party. The $39.5 million purchase price, which was reduced by a purchase price adjustment of $3.9 million and proceeds of $5.0 million received from the subsequent sale of a portion of the assets acquired, was financed by borrowings under our revolving bank credit facility. The purchase price was adjusted 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 (January 1, 2002) and the closing date (May 30, 2002).

Conoco Acquisition. On December 31, 2001, we completed the purchase from Conoco Inc. of natural gas and oil properties and associated gathering pipelines and equipment, together with developed and undeveloped acreage, located in the Webb and Zapata Counties of South Texas. The $69 million cash purchase price was 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 we acquired. Our average working interest is 87%. Total proved reserves associated with the interests acquired were 85 Bcfe, as of

October 1, 2001, the effective date of the transaction.

OTHER RECENT DEVELOPMENTS

Joint Offshore Exploration Program. Effective September 1, 2002, we entered into a joint offshore exploration agreement with El Paso Production Oil & Gas USA, L.P., a subsidiary of El Paso Corporation. Under the terms of the agreement, El Paso contributed approximately $50 million for land, seismic and drilling costs in exchange for 50% of our working interest in six specified prospects that we developed. El Paso pays 100% of the drilling costs to casing point or 100% of the "dry hole costs", except for the High Island 115 prospect for which we have an obligation of $5 million for dry hole costs. El Paso is the operator of four of the wells and we are operator of the remaining two. Under the terms of the agreement, El Paso has the option to extend the exploration agreement beyond the initial six well program. The option expires in August 2003. As of the date of this report, four wells in the program have been drilled. Two resulted in discoveries and have been successfully completed and placed on-line. One well has been completed and is currently testing and the fourth well has been temporarily abandoned and is being evaluated for further completion. The fifth well in the program, High Island 115, is operated by El Paso and currently drilling to a target depth of 21,000 feet. The sixth well in the program is currently planned for the second quarter of 2003. El Paso will operate this well and if they elect not to drill the final well, all interests in the prospect will revert back to us.

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. The "high-cost/tight-gas formation" designation will allow us to receive an abatement of severance taxes for qualifying wells in various fields. For qualifying wells, production will be either exempt from tax or taxed at a reduced rate until certain capital costs are recovered. For qualifying wells, we will also be entitled to a refund of severance taxes paid during a designated prior 48-month period. Applications for refund are submitted on a well-by-well basis to the State Comptroller's Office and due to timing of the acceptance of applications, we are unable to project the 48-month look-back period for qualifying refunds. We currently estimate that the total refund, for 2002 and prior periods, will be between $18 million to $23 million ($12 million to $15 million, net of tax), although we can provide no assurances that the actual total refund amount will fall within our current estimate. During the fourth quarter of 2002, we recorded refunds totaling $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.

2003 CAPITAL EXPENDITURE PLANS

For 2003, we have budgeted $286 million for capital investments in natural gas and oil properties. The table below summarizes by area where we plan to spend our exploration and development dollars together with an estimate of wells planned for each area. The amount and allocation of our capital investment program is subject to change based on operational developments, commodity prices, service costs, acquisitions and numerous other factors. Of the $286 million budgeted for 2003, approximately $21 million of the budget includes capitalized interest and general and administrative expenses. Generally we do not budget for acquisitions. The table below reflects our 2003 capital spending plans as of the date of this report; however, there can be no assurances that actual amounts spent and wells drilled will equal amounts budgeted.

ESTIMATES FOR THE YEAR ENDED DECEMBER 31, 2003

	(IN THOUSANDS, EXCEPT WELLS) WELLS PLANNED	$ EXPLORATION	$ DEVELOPMENT	TO E
Onshore	103	$ 10,700	$ 139,300	
Offshore	16	61,000	54,000	
	119	$ 71,700	$ 193,300	
Capitalized expenses				
Total capital expenditures				

NATURAL GAS AND OIL RESERVES

The following table summarizes the estimates of our historical net proved reserves as of December 31, 2002, 2001 and 2000, 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:(1)	2002	2001
		(IN THOUSANDS)
Natural gas (MMcf)..	610,409	568,208
Oil (MBbls)...	6,533	6,605
Total (MMcfe)...	649,607	607,838
Present value of future net revenues before income taxes(2)......	$ 1,326,314	$ 714,416
Standardized measure of discounted future net cash flows(3)......	$ 1,058,064	$ 551,525

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(1) Netherland, Sewell & Associates engineered reserve data for our Gulf of Mexico properties and our South Texas properties which represent present values of approximately 83%, 79% and 78%, respectively, of our reserves at December 31, 2002, 2001 and 2000. Miller and Lents

engineered reserve data for the remainder of our onshore properties which represent approximately 17%, 21% and 22%, respectively, of the present values attributable to our proved reserves at December 31, 2002, 2001 and 2000.

(2) 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 SEC guidelines, the PV10 includes the fair value of our natural gas and oil hedges in place at December 31, 2002, 2001 and 2000 of a negative $38.6 million, a positive $65.8 million and a negative $70.6 million, respectively. Year-end prices per Mcf of natural gas used in making the present value determinations as of December 31, 2002, 2001 and 2000 were $4.35, $2.38 and $9.55, respectively. Year-end prices per Bbl of oil used in making the present value determinations as of December 31, 2002, 2001 and 2000 were $28.74, $17.78 and $24.69, respectively.

(3) The standardized measure of discounted future net cash flows represents the present value of future net revenues after income tax discounted at 10% per annum and has been calculated in accordance with SFAS No. 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 Securities and Exchange Commission, we estimate our 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. Gas prices, which have fluctuated widely in recent years, affect estimated quantities of proved reserves and future net revenues. Any estimates of natural gas and oil reserves and their values are inherently uncertain, 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 of different engineers, including those we use, may vary. In addition, estimates of reserves may be revised based upon actual production, results of future development and exploration activities, prevailing natural gas and oil prices, operating costs and other factors, which revision may be material. Accordingly, reserve estimates may be 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.

DRILLING ACTIVITY

The following table sets forth our drilling activity on our properties for the years ended December 31, 2002, 2001 and 2000.

	YEAR ENDED DECEMBER 31			
	2002		2001	
	GROSS	NET	GROSS	NET
ONSHORE DRILLING ACTIVITY				
EXPLORATORY				
Productive	2	2.0	1	
Non-Productive	2	1.8	3	
Total onshore exploratory	4	3.8	4	
DEVELOPMENT				
Productive	73	64.0	60	4
Non-Productive	10	9.4	12	
Total onshore development	83	73.4	72	5
TOTAL ONSHORE WELLS DRILLED	87	77.2	76	5
OFFSHORE DRILLING ACTIVITY				
EXPLORATORY				
Productive	6	2.0	7	
Non-Productive	1	0.4	5	
Total offshore exploratory	7	2.4	12	
DEVELOPMENT				
Productive	3	1.1	7	
Non-Productive	--	--	1	
Total offshore development	3	1.1	8	
TOTAL OFFSHORE WELLS DRILLED	10	3.5	20	1
TOTAL WELLS DRILLED	97	80.7	96	7

PRODUCTIVE WELLS

The following table sets forth the number of productive wells in which we owned an interest as of December 31, 2002.

	OIL WELLS		NATURAL GAS WELLS			
	OPERATED		OPERATED		NON-OPERATED	
	GROSS	NET	GROSS	NET	GROSS	NET
South Texas	--	--	450	313.6	112	12.
Gulf of Mexico	6	3.8	48	31.1	25	5.
Arkoma	--	--	131	72.7	121	18.
Other onshore	2	1.4	651	395.9	55	11.

Total	8	5.2	1,280	813.3	313	48.

Productive wells consist of producing 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. All of our wells classified as "oil" producers are operated by us.

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, 2002. 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.

	AT DECEMBER 31, 2002				
	TOTAL ACRES		DEVELOPED ACRES		UNDEVEL
	GROSS	NET	GROSS	NET	GROSS
South Texas	92,165	71,014	66,458	49,898	25,70
Gulf of Mexico(1)	423,212	328,361	207,599	131,856	215,61
Arkoma Basin	75,071	34,111	52,032	26,278	23,03
Other onshore	74,206	50,589	70,899	47,615	3,30
Total	664,654	484,075	396,988	255,647	267,66

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(1) Gulf of Mexico includes acreage in federal and state waters.

MARKETING AND CUSTOMERS

We market the majority of all 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 (less than 12 months) 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 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, please see "Notes to Consolidated Financial Statements - Note 8 - Sales to Major Customers."

We enter into commodity swaps 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 detailed discussion, please read 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."

We incur gathering and transportation expenses to move our 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 oil and natural gas 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. Please read the section entitled "Risk Factors -- Operating Hazards and Uninsured Risks."

ABANDONMENT COSTS

We are responsible for our working interest share of costs to abandon natural gas and oil properties and facilities once they are depleted. We have historically provided for our expected future abandonment liabilities as a component of our future development costs which have been included in our calculation of depreciation, depletion and amortization as the properties are produced. Our estimates of abandonment costs and their timing may change as a result of many factors including actual drilling and production results, inflation rates, and changes in environmental laws and regulations. Pursuant to our adoption of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" on January 1, 2003, we estimate our discounted future net asset retirement obligation for all of our natural gas and oil properties and equipment to be approximately $57 million. SFAS No. 143 requires that the fair value of a liability for an asset's retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized.

The Minerals Management Service requires lessees of Outer Continental Shelf properties to post bonds in connection with the plugging and abandonment of wells located offshore and the removal of all production facilities. Operators in the Outer Continental Shelf waters of the Gulf of Mexico are currently required to post an area-wide bond of $3 million or $500,000 per producing lease. We are presently exempt from any requirement by the Minerals Management Service to provide supplemental bonding on our offshore leases, although we may not be able to continue to satisfy the requirements for this exemption in the future. We believe that even if we did not qualify for this exemption, the cost of any bonding requirements would not materially affect our financial condition or results of operations. The Minerals Management Service has the authority to suspend or terminate operations on federal leases for failure to comply with applicable bonding requirements or other regulations applicable to plugging and abandonment. Any suspensions or terminations of our operations could have a material adverse effect on our financial condition and results of operations.

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. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to these properties in accordance with standards generally accepted in the oil and gas industry. Prior to completing an acquisition of producing natural gas and oil leases, we obtain title opinions on the most significant leases. Our natural gas and oil properties are subject to customary royalty 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 producing properties and proved undeveloped acreage. 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 larger operating staffs and 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. 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 or human resources permit. Our ability to acquire additional properties and to discover 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.

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 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 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 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 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. Generally, 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.

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 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 must comply with federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may:

- require the acquisition of a permit before drilling commences;
- 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, 2002, 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 2003 or that will have a material impact on our financial position or results of operations.

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.

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 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, we may be 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 not 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. 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 MMS 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 compliance with the financial responsibility provisions of the Oil Pollution Act.

Federal Water Pollution Control Act. The Federal Water Pollution Control 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. 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 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, more stringent regulations governing emissions of toxic air pollutants are being developed by the EPA, and 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.

Natural Gas Sales Transportation. Historically, federal legislation and regulatory controls affect 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 on January 1, 1993 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 affect 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 and regulations that significantly fostered competition in the business of transporting and marketing gas. These orders and regulations induced, and ultimately required, interstate pipeline companies to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether shippers were 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.

Under FERC's current regulatory regime, transmission services must be provided on an open-access, non- discriminatory basis at cost-based rates. 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 jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting gas to point-of-sale locations.

RISK FACTORS AFFECTING OUR BUSINESS

OUR BUSINESS AND OPERATIONS COULD BE ADVERSELY AFFECTED BY RECENT TERRORIST.

On September 11, 2001, the United States was the target of terrorist attacks of unprecedented scope, and the United States and others instituted military action in response. Since the September 11th attacks, the U.S. government has issued public warnings that indicate that energy assets might be specific targets of terrorist organizations. The continued threat of terrorism and the impact of military and other actions will likely lead to increased volatility in prices for natural gas and oil and could affect the markets for our operations. In addition, future acts of terrorism could be directed against companies operating in the United States, particularly those engaged in sectors essential to our economic prosperity, such as natural resources. These developments have subjected our operations to increased risk and, depending on their ultimate magnitude, could have a material adverse affect on 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 oil and natural gas prices may significantly change our revenues, results of operations, cash flows and proved reserves. Historically, the markets for natural gas and oil have been volatile and are likely to continue to be volatile in the future. Prices for natural gas and oil may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of natural gas and oil;
- the price of foreign imports;
- overall domestic and global economic conditions;
- 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 may be reduced, which may result in a material decline in our revenues.

WE MAY BE REQUIRED TO TAKE ADDITIONAL WRITEDOWNS IF NATURAL GAS AND OIL PRICES DECLINE.

We may be required under full cost accounting rules to write down the carrying value of our natural gas and oil properties 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.

For the quarter ended December 31, 2001, we were required under SEC accounting rules to take a non-cash charge to impair or reduce the carrying value of our oil and gas properties by $6.2 million ($4.0 million net of tax). The charge was primarily a result of low natural gas prices. We may be required to take additional write downs in future periods should prices decline to unfavorable levels or if we have unsuccessful drilling results.

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 outstanding indebtedness at December 31, 2002 was $252 million, and as of February 20, 2003 was $247 million. Further, as of February 20, 2003, we have remaining borrowing capacity under our credit facility of $152.6 million, which we may use for future acquisitions. 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. During 2002 and 2001, we made aggregate cash interest payments of $14.9 million and $14.8 million, respectively. 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. Moreover, 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 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. 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.

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;
- 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.

Additionally, our natural gas and oil operations located in the Gulf of Mexico may experience tropical weather disturbances, some of which can be severe enough to cause substantial damage to facilities and possibly interrupt production. 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.

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.

DRILLING OIL AND NATURAL GAS 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 oil and natural gas 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 portion of our natural gas and oil production. The hedging instruments we generally use, such as fixed price swaps, collars and options, expose us to a number of risks, including instances where our hedging contracts will not permit us to realize the full benefit of higher natural gas prices. In addition, there is the risk that our actual production is less than expected and that the counterparty to the hedging contract defaults on its contractual obligations.

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. 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 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. Recent market conditions resulting in downgrades to credit ratings of energy merchants have affected the liquidity of several of our purchasers. During the third quarter of 2002, we discontinued selling our natural gas and oil to several energy merchants that received downgrades to their credit ratings.

Further, 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 66% of our common stock. 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, four of our nine other directors are currently or were 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; and James Q. Riordan, Chairman of our Audit Committee, retired from KeySpan's Board in May 2002.

INVESTORS WILL HAVE VERY LIMITED ABILITY TO RECOVER AGAINST OUR FORMER AUDITORS WITH RESPECT TO OUR FINANCIAL STATEMENTS.

On March 29, 2002, we dismissed Arthur Andersen LLP and engaged Deloitte & Touche LLP as our independent public accountants. Our consolidated financial statements as of and for the years ended December 31, 2000, 1999 and 1998 were audited by Arthur Andersen, as indicated in their report with respect thereto. The firm Arthur Andersen was convicted of obstruction of justice relating to a federal investigation of Enron Corp., has ceased operations and has lost the services of the material personnel responsible for our audit. As a result, it is not possible to obtain Arthur Andersen's consent to the incorporation by reference of their report in future filings with the SEC under the Securities Act of 1933. Because Arthur Andersen will not be deemed to have consented to the incorporation by reference of their report in such filings, investors will not be able to recover against Arthur Andersen under Section 11 of the Securities Act for any untrue statements of a material fact contained in the financial statements audited by Arthur Andersen or any omissions to state a material fact required to be stated therein.

EMPLOYEES

As of December 31, 2002, we had 145 full time employees, 101 of whom are located at our headquarters in Houston, Texas and the remainder of whom are located in our South Texas, Arkansas, West Virginia and East Texas field offices. None of our employees are represented by a labor union. 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. 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 other filings pursuant to Section 13 (a) or 15 (d) of the Exchange Act are 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 Securities and Exchange Commission.

ITEM 3. LEGAL PROCEEDINGS

On August 18, 2002, a complaint styled Victor Ramirez, Santiago Ramirez, Jr., Oswaldo H. Ramirez and Javier Ramirez as Co-Trustees of the Ramirez Mineral Trust v. The Houston Exploration Company, cause number 5,207, was filed in the district court of the 49th Judicial District in Zapata County, Texas. The complaint alleges that we trespassed by drilling the No. 7 RMT well to a depth in excess of our lease rights and commingled production by producing from the excess depth. The plaintiffs claim damages for trespass and conversion in excess of $6 million and further seek to recover exemplary damages in excess of $18 million. At February 20, 2003, the issuance date of our original report, we were in the discovery stage of the litigation process for this claim. We believe that the claim will not have a material adverse effect on our financial condition or results of operations.

With the exception of the matter described above, we are not a party to any material pending legal proceedings, other than ordinary routine litigation incidental to our business that management believes 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, 2002.

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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, 2000 through December 31, 2002 as reported on the New York Stock Exchange:

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

YEAR ENDED DECEMBER 31, 2001	HIGH	LOW
First Quarter	$ 39.21	$ 27.45
Second Quarter	$ 38.00	$ 24.90
Third Quarter	$ 34.26	$ 22.20
Fourth Quarter	$ 35.00	$ 23.10

As of February 20, 2003, 30,961,418 shares of common stock were outstanding and we had approximately 40 stockholders of record and approximately 3,500 beneficial owners.

DIVIDENDS

We have never 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. Moreover, our bank credit facility and the indenture governing our 8?% Senior Subordinated Notes due 2008 contain restrictions on the payment of dividends to holders of common stock. Accordingly, were our dividend policy to change in the future, our ability to pay dividends would be subject to these restrictions and our results of operations, financial condition, capital requirements and other factors deemed relevant by the Board of Directors. Please read Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The table below lists the number of stock options and restricted stock that would be issued upon exercise of grants made under equity compensation plans that have been approved by our stockholders (the 1996 Stock Option Plan and the 2002 Long-Term Incentive Plan) and under equity compensation plans or other grants that have not been approved by our stockholders (primarily option grants under our 1999 Non-Qualified Stock Option Plan). We have not issued any warrants or rights.

EQUITY COMPENSATION PLAN TABLE PURSUANT TO RULE 102(b)

PLAN CATEGORY	NUMBER OF SECURITIES TO BE ISSUED UPON EXERCISE OF OUTSTANDING OPTIONS, WARRANTS AND RIGHTS	WEIGHTED AVERAGED EXERCISE PRICE OF OUTSTANDING OPTIONS, WARRANTS AND RIGHTS	NUMBER REMAINI FOR FUT
Equity compensation plans approved by shareholders	1,708,142	$ 27.63	
Equity compensation plans not approved by shareholders(1)	720,191	27.19	
Total	2,428,333	$ 27.50	

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(1) Includes shares issued under our 1999 Non-Qualified Stock Option Plan and 6,667 shares of restricted stock that remain outstanding and that were issued to our Chief Executive Officer in April 2001 pursuant to the terms of his employment contract.

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, 2002. 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		
	2002	2001	2000
	(IN THOUSANDS, EXCEPT PER SH		

INCOME STATEMENT DATA:			
REVENUES:			
Natural gas and oil revenues(1)	$ 344,295	$ 387,156	$ 277,487
Other	1,086	1,353	1,738
Total revenues(1)	345,381	388,509	279,225
EXPENSES:			
Lease operating expense	33,976	25,291	23,553
Severance tax (2)	9,487	11,035	9,757
Transportation expense (1)	9,317	7,652	6,892
Depreciation, depletion and amortization	171,610	128,736	89,239
Writedown in carrying value	--	6,170	--
General and administrative, net	13,077	17,110	8,928
Total operating expenses	237,467	195,994	138,369
Income (loss) from operations	107,914	192,515	140,856
Other (income) expense (3)	(9,070)	119	1,752
Interest expense, net	7,398	2,992	11,361
Income (loss) before income taxes	109,586	189,404	127,743
Income tax provision (benefit)	39,092	66,803	42,485
NET INCOME (LOSS)	$ 70,494	$ 122,601	$ 85,258
Net income (loss) per share	$ 2.31	$ 4.06	$ 3.06
Net income (loss) per share--diluted	$ 2.28	$ 4.00	$ 3.02
Weighted average shares	30,569	30,228	27,860
Weighted average shares--diluted	30,878	30,645	28,213
Ratio of earnings to fixed charges (4)	7.6x	12.8x	5.5x
CASH FLOW DATA:			
Net cash flows from operating activities before adjustments for working capital	$ 282,049	$ 325,214	$ 217,800
Net cash provided by operating activities	243,869	358,032	200,791
Net cash used in investing activities	252,125	368,277	184,512
Net cash provided (used) in financing activities	17,668	9,189	(22,106)

	AT DECEMBER 31,			
	2002	2001	2000	1999
BALANCE SHEET DATA:				
Working capital (deficit)	$ (1,702)	$ 34,314	$ 19,746	$ (71
Property, plant and equipment, net	1,022,414	938,761	705,390	610
Total assets	1,138,816	1,059,092	837,384	678
Long-term debt and notes	252,000	244,000	245,000	281
Stockholders' equity	592,789	565,881	396,742	217

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(1) For all periods presented, we applied Emerging Issues Task Force ("EITF") No. 00-10 "Accounting for Shipping and Handling Fees and Costs." Pursuant to our application of EITF No. 00-10, 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. The application of EITF No. 00-10 has no effect on income from operations or net income. See Note 11 - Restatement and Reclassification - Application of EITF No. 00-10 - Transportation Expense.

(2) Severance tax expense for 2002 is reported net of a reduction of $1.3 million for expense incurred and recorded in 2002 pursuant to the 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.

(3) For 2002, other income of $9.1 million represents a refund of prior period severance tax expense recorded pursuant to the receipt of a "high cost/tight sand" designation for a portion of our South Texas production. 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. Please see Note 6 - Related Party Transactions.

(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). For the year ended December 31, 1998, ratio of earnings to fixed charges was less than one-to-one coverage due to a deficiency of $123.2 million caused by a writedown of the carrying value of our natural gas and oil properties of $130 million ($84.5 million after taxes).

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

As discussed in Notes to the Consolidated Financial Statements - Note 11 - Restatement and Reclassifications, the accompanying 2001 consolidated financial statements have been restated. The restatements have no effect on income from operations or net income. The following Management's Discussion and Analysis of Financial Condition and Results of Operations reflects this restatement.

GENERAL

We are an independent natural gas and oil company engaged in the exploration, development, exploitation and acquisition of domestic natural gas and oil properties. Our operations are primarily focused in South Texas, offshore in the Gulf of Mexico and in the Arkoma Basin of Oklahoma and Arkansas.

At December 31, 2002, our net proved reserves were 650 billion cubic feet equivalent or Bcfe, with a present value, discounted at 10% per annum, of cash flows before income taxes of $1.3 billion. Our reserves are fully engineered on an annual basis by independent petroleum engineers. Our focus is natural gas. Approximately 94% of our net proved reserves at December 31, 2002 were natural gas, approximately 69% of which were classified as proved developed. We operate approximately 85% of our properties.

During the year ended December 31, 2002 we drilled a total of 97 wells of which 84 were successful reflecting a success rate of 86%. We produced a total of 103 billion cubic feet equivalent, or Bcfe, and increased our average daily production during the year by 14% to 281 million cubic feet equivalent, or MMcfe, per day. We replaced 141% of our production by adding 145 Bcfe in net proved reserves. We generated $282 million in cash flows from operations before adjustments for changes in current assets and liabilities and invested a net $253 million in natural gas and oil properties, including $65 million for producing properties acquired in South Texas and the Gulf of Mexico.

We began exploring for natural gas and oil in December 1985 on behalf of The Brooklyn Union Gas Company. Brooklyn Union is an indirect wholly owned subsidiary 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, 2002, THEC Holdings Corp., an indirect wholly owned subsidiary of KeySpan, owned approximately 66% of the outstanding shares of our common stock.

As an independent oil and gas producer, our revenue, profitability and future rate of growth are substantially dependent upon prevailing prices for natural gas and oil, our ability to find and produce natural gas and oil and our ability to control and reduce costs, all of which are dependent upon numerous factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. The energy markets have historically been very volatile and commodity prices may fluctuate widely in the future. 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 access to capital.

CRITICAL ACCOUNTING POLICIES AND USE OF ESTIMATES

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.

Hedging Activities. On January 1, 2001, we adopted Statements of Financial Accounting Standards No. 133, as amended, "Accounting for Derivative Instruments and Hedging Activities." 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.

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 (i) our full cost pool; less (ii) our unevaluated properties and their related costs which are excluded from the amortization base until we have made a determination as to the existence of proved reserves; plus (iii) estimates for future development costs as well as future abandonment and dismantlement costs. We review our unevaluated properties at the end of each quarter to determine if 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 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, held constant over the life of the reserves. We use derivative financial instruments that qualify for hedge accounting under SFAS No. 133 to hedge against the volatility of natural gas prices, and in accordance with current 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, 2002, we estimated that we had a full cost ceiling "cushion", whereby the carrying value of our full cost pool was less than the ceiling limitation. No writedown is required when a cushion exists. Natural gas prices continue to be volatile and the risk that we will be required to write down our full cost pool increases when natural gas prices are depressed or if we have significant downward revisions in our estimated proved reserves.

Use of Estimates. The preparation of the consolidated financial statements in conformity with accounting principals generally accepted in the United States of America requires our 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 limitation.

Natural gas and oil reserve quantities represent estimates only. Under full cost accounting, we use reserve estimates to determine our full cost ceiling limitation as well as our depletion rate. We estimate our 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 prices, which have fluctuated widely in recent years, affect estimated quantities of proved reserves and future net revenues. Further, any estimates of natural gas and oil reserves and their values are inherently uncertain for numerous reasons, including many factors beyond our control. 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. In addition, estimates of reserves may be revised based upon actual production, results of future development and exploration activities, prevailing natural gas and oil prices, operating costs and other factors, and these revisions may be material. Reserve estimates are highly dependent upon the accuracy of the underlying assumptions. Actual future production may be materially different from estimated reserve quantities and the differences could materially affect future amortization of natural gas and oil properties.

Accounting for Stock Option Expense. For the years ended December 31, 2002, 2001 and 2000, we accounted for stock options using the intrinsic value method prescribed under Accounting Principles Board Opinion 25 and accordingly, we did not recognize compensation expense for stock options. On January 1, 2003, we adopted the fair value expense recognition provisions of SFAS No. 123 "Accounting for Stock-Based Compensation" and as amended by SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure." SFAS No. 148 proposes three alternatives transition methods for adopting the fair value method under SFAS No. 123:

- Prospective Method - recognize fair value expense for all awards granted in the year of adoption but not previous awards;

- Modified Prospective Method - recognize fair value expense for the unvested portion of all stock options granted, modified, or settled since 1994 (i.e., the unvested portion of the prior awards or those granted in the year of adoption must be recorded using the fair value method); and

- Retroactive Restatement Method - similar to the Modified Prospective Method except that all prior periods are restated.

We adopted SFAS No. 123 using the Prospective Method and as a result will record as compensation expense the fair value of all stock options issued subsequent to January 1, 2003. We do not expect the adoption of the provisions of SFAS No. 123 to have a material impact on our financial position, results of operations or cash flows.

NEW ACCOUNTING PRONOUNCEMENTS

SFAS No. 141, "Business Combinations" and SFAS No. 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 clarify that more assets should be distinguished and classified between tangible and intangible. We understand that the issue is under evaluation as to whether provisions of SFAS No. 141 and SFAS No. 142 may call for mineral rights held under lease or other contractual arrangements to be classified in the balance sheet as intangible assets together with cash costs of oil and gas leasehold interests acquired. The issue is under review, because it is believed that no oil and gas exploration and production company was known to have changed their tangible asset balance sheet classification of mineral rights or leasehold costs upon adopting of SFAS Nos. 141 and 142, including us. If these types of leasehold costs (both proved and unevaluated) are determined to be intangible assets, they would be classified separately from oil and natural gas properties as intangible assets on our balance sheets. This issue relates only to balance sheet classification and presentation and will not have an effect on cash flows or results of operations. For the years ended December 31, 2002 and 2001, $161.0 million and $81.9 million, respectively, would be reclassified from tangibles to intangibles representing costs incurred, net of accumulated amortization, since June 30, 2001, the effective date of SFAS No. 141. We will continue to classify our oil and gas leasehold costs as tangible oil and natural gas properties until further guidance is provided.

SFAS No. 143, "Accounting for Asset Retirement Obligations," addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 takes effect January 1, 2003. SFAS No. 143 requires that the fair value of a liability for an asset's retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. For all periods presented, we have included estimated future costs of abandonment and dismantlement in our full cost amortization base and amortize these costs as a component of our depletion expense.

We have completed our assessment of SFAS No. 143. At December 31, 2002, we estimate that the present value of our future Asset Retirement Obligation ("ARO") for natural gas and oil property and related equipment is approximately $57 million. We estimate that the cumulative effect of our adoption of SFAS No. 143 and the change in the accounting principle will be a charge to net income during the first quarter of 2003 of $4.3 million, $2.8 million net of taxes.

In April 2002 the Financial Accounting Standards Board ("FASB") issued SFAS No. 145, "Rescission of FASB Statements No. 4, No. 44, and No. 64, Amendment to FASB Statement No. 13 and Technical Corrections." SFAS No. 145 streamlines the reporting of debt extinguishments and requires that only gains and losses from extinguishments meeting the criteria in Accounting Policies Board Opinion 30 would be classified as extraordinary. Thus, gains or losses arising from extinguishments that are part of a company's recurring operations would not be reported as an extraordinary item. SFAS No. 145 is effective for fiscal years beginning after May 15, 2002. At this time, we do not expect the adoption of SFAS No. 145 to have a material impact on our financial position, results of operations or cash flows.

SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" was issued in September 2002 and addresses accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging

Issues Task

Force ("EITF") Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred. Under Issue 94-3, a liability for an exit cost was recognized at the date of an entity's commitment to an exit plan. Under SFAS No 146, fair value is the objective for initial measurement of the liability. SFAS No. 146 is effective for exit or disposal activities that are initiated after December 31, 2002. At this time, we do not expect the adoption of SFAS No. 146 to have a material impact on our financial position, results of operations or cash flows.

SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure" was issued in December 2002 and the transition guidance and annual disclosure provisions are effective for us for the year ended December 31, 2002. SFAS No. 148 amends SFAS Statement No. 123, "Accounting for Stock Based Compensation" and provides alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, the statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based compensation and the effect of the method used. We adopted SFAS No. 148 for 2002 and on January 1, 2003, we adopted the fair value expense recognition provisions of SFAS No. 123 on a prospective basis and as a result, we will record as compensation expense the fair value of all stock options issued subsequent to January 1, 2003.

ACQUISITIONS

KeySpan Joint Venture Assets. On October 11, 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. 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. The interests purchased were in the following blocks: Vermilion 408, East Cameron 81 and 84, High Island 115, Galveston Island 190 and 389, Matagorda Island 704 and North Padre Island 883. KeySpan has retained its 45% interest in four blocks: South Timbalier 314 and 317 and Mustang Island 725 and 726, as these blocks are in various stages of development. KeySpan has committed to continued participation in the ongoing development of these blocks including the completion of the platform and production facilities at South Timbalier 314/317 together with possible further developmental drilling at both South Timbalier 314/317 and Mustang Island 725/726. As of 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 the purchase price by a total of $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.

Our Board of Directors appointed a special committee, comprised entirely of independent directors to review the proposed transaction with KeySpan. In addition, the special committee discussed the history and terms of the transaction with our senior management. After completing its review, the special committee unanimously concluded that the transaction was advisable and in our best interests and that the terms of the transaction were at least as favorable to us as terms that would have been obtainable at the time in a comparable transaction with an unaffiliated party.

Burlington Acquisition. On May 30, 2002, we completed the purchase of natural gas and oil producing properties, together with undeveloped acreage, from Burlington Resources Inc. located in the Webb and Jim Hogg Counties of South Texas. The properties purchased cover approximately 24,800 gross (10,800 net) acres located in the North East Thompsonville and South Laredo Fields. The properties purchased represent interests in approximately 123 producing wells and total proved reserves of 37 Bcfe as of January 1, 2002, the effective date of the transaction. The North East Thompsonville Field has 10 wells producing from the Wilcox formation, all of which we operate. This field represents approximately 70% of the proved reserves and 75% of the current production associated with the acquisition. The South Laredo Field, located in Webb County and in the Lobo Trend, contains 113 wells, all operated by a third party. The $39.5 million purchase price, which was reduced by a purchase price adjustment of $3.9 million and proceeds of $5.0 million received from the subsequent sale of a portion of the assets acquired, was financed by borrowings under our revolving bank credit facility. 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 (January 1, 2002) and the closing date (May 30, 2002).

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Conoco Acquisition. On December 31, 2001, we completed the purchase from Conoco Inc. of natural gas and oil properties and associated gathering pipelines and equipment, together with developed and undeveloped acreage, located in the Webb and Zapata Counties of South Texas. The $69 million cash purchase price was 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 we acquired. 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.

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OTHER RECENT DEVELOPMENTS

Joint Offshore Exploration Program. Effective September 1, 2002, we entered into a joint offshore exploration agreement with El Paso Production Oil & Gas USA, L.P., a subsidiary of El Paso Corporation. Under the terms of the agreement, El Paso contributed approximately $50 million for land, seismic and drilling costs in exchange for 50% of our working interest in six specified prospects that we developed. El Paso pays 100% of the drilling costs to casing point or 100% of the "dry hole costs", except for the High Island 115 prospect for which we have an obligation of $5 million for dry hole costs. El Paso is the operator of four of the wells and we are operator of the remaining two. Under the terms of the agreement, El Paso has the option to extend the exploration agreement beyond the initial six well program. The option expires in August 2003. As of the date of this report, four wells in the program have been drilled. Two resulted in discoveries and have been successfully completed and placed on-line. One well has been completed and is currently testing and the fourth well has been temporarily abandoned and is being evaluated for further completion. The fifth well in the program, High Island 115, is currently drilling to a target depth of 21,000 feet. The sixth well in the program is currently planned for the second quarter of 2003. El Paso will operate this well and if they elect not to drill the final well, all interests in the prospect will revert back to us.

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. The "high-cost/tight-gas formation" designation will allow us to receive an abatement of severance taxes for qualifying wells in various fields. For qualifying wells, production will be either exempt from tax or taxed at a reduced rate until certain capital costs are recovered. For qualifying wells, we will also be entitled to a refund of severance taxes paid during a designated prior 48-month period. Applications for refund are submitted on a well-by-well basis to the State Comptroller's Office and due to timing of the acceptance of applications, we are unable to project the 48-month look-back period for qualifying refunds. We currently estimate that the total refund, for 2002 and prior periods, will be between $18 million to $23 million ($12 million to $15 million, net of tax), although we can provide no assurances that the actual total refund amount will fall within our current estimate. During the fourth quarter of 2002, we recorded refunds totaling $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.

RESULTS OF OPERATIONS

The following table sets forth our historical natural gas and oil production data during the periods indicated:

	YEARS ENDED	
	2002	
SUMMARY OPERATING INFORMATION:		
Operating revenues	$ 345,381	$
Operating expenses	237,467	
Income from operations	107,914	
Net income	$ 70,494	$
PRODUCTION:		

Natural gas (MMcf)		97,368	
Oil (MBbls)		859	
Total (MMcfe)		102,522	
Average daily production (MMcfe/day)		281	
AVERAGE SALES PRICES:			
Natural gas (per Mcf) realized (1)	$	3.32	$
Natural Gas (per Mcf) unhedged		3.16	
Oil (per Bbl)		23.99	
OPERATING EXPENSES (PER MCFE):			
Lease operating expense	$	0.33	$
Severance tax		0.09	
Transportation expense		0.09	
Depreciation, depletion and amortization		1.67	
Writedown in carrying value of natural gas and oil properties		--	
General and administrative, net		0.13	

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

RECENT FINANCIAL AND OPERATING RESULTS

Comparison of Years Ended December 31, 2002 and 2001

Production. Our production increased 14% from 89,849 million cubic feet equivalent, or MMcfe, for the year ended December 31, 2001 to 102,522 MMcfe for the year ended December 31, 2002. The increase in production 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.

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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 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.

Natural Gas and Oil Revenues. Natural gas and oil revenues decreased 11% from $387.2 million for year ended December 31, 2001 to $344.3 million for the year ended 2002 as a result of a 24% decrease in average realized natural gas prices, from $4.32 per Mcf during 2001 to $3.32 per Mcf in 2002, offset in part by a 14% increase in production for the same period.

Natural Gas Prices. As a result of hedging activities, we realized an average gas price of $3.32 per Mcf for the year ended 2002, which was 105% of the average unhedged natural gas price of $3.16 that we otherwise would have received, resulting in natural gas and oil revenues for 2002 that were $16.4 million higher than the revenues we would have achieved if hedges had not been in place during the year. For the corresponding period during 2001, we realized an average gas price of $4.32 per Mcf, which was 103% of the average unhedged natural gas price of $4.18 that otherwise would have been received, resulting in natural gas and oil revenues that were $12.9 million higher than the revenues we would have achieved if hedges had not been in place during the period.

Lease Operating Expense. Lease operating expenses increased 34% from $25.3 million in 2001 to $34.0 million in 2002. On an Mcfe basis, lease operating expenses increased 18% from $0.28 per Mcfe during 2001 to $0.33 per Mcfe during 2002. The increase in both lease operating expenses and lease operating expenses per unit is attributable to the continued expansion of our operations onshore and offshore combined with an increase in expenses 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. Severance tax, which is a function of volume and revenues generated from onshore production, decreased 14% from $11.0 million during 2001 to $9.5 million during 2002. On an Mcfe basis, severance tax decreased from $0.12 per Mcfe during 2001 to $0.09 per Mcfe during 2002. 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 recorded 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.

Transportation Expense. We applied Emerging Issues Task Force ("EITF") No. 00-10 "Accounting for Shipping and Handling Fees and Costs" for all periods presented. Pursuant to our application of EITF No. 00-10, transportation expenses previously reflected as a reduction of natural gas and oil revenues were added back to the related revenues and reclassified as a separate component of operating expense. For the year ended December 31, 2001, natural gas and oil revenues, total revenues, transportation expense and total operating expenses were restated. The application of EITF No. 00-10 had no effect on operating income or net income. See Note 11 - Restatement and Reclassification Made to Consolidated Statements of Operations for Transportation Expense.

Transportation expense for 2002 increased 21% from $7.7 million and $0.09 per Mcfe during 2001 to $9.3 million and $0.09 per Mcfe during 2002. The increase in expense is due primarily to the 32% increase in our onshore production volume during 2002 as compared to 2001.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased 33% from $128.7 million during 2001 to $171.6 million for the year of 2002. Depreciation, depletion and amortization expense per Mcfe increased 17% from $1.43 during 2001 to $1.67 during 2002. The increase in depreciation, depletion and amortization expense was a result of higher production volumes combined with a higher depletion rate. Our depletion rate has increased during 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 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. Because the Outer Continental Shelf is a mature producing area, it is becoming increasingly more difficult to find and develop new reserves at historical costs.

General and Administrative Expenses, Net of Capitalized General and Administrative Expenses and Overhead Reimbursements. General and administrative expenses, net of overhead reimbursements received from other working interest owners of $1.2 million and $1.8 million during 2001 and 2002, respectively, and capitalized general and administrative expenses directly related to oil and gas exploration and development activities of $12.8 million and $13.2 million, respectively, for 2001 and 2002, decreased 23% from $17.1 million during 2001 to $13.1 million during 2002. Aggregate general and administrative expenses decreased 10% from $31.2 million during 2001 to $28.1 million during 2002. Included in aggregate and net administrative expenses during 2001 were payments totaling $5.2 million made in connection with the termination of former executive officers' employment contracts.

Excluding the one-time charges during 2001 for the termination of employment contracts, aggregate general and administrative expenses would have been $26.0 million in 2001 compared to $28.1 million for 2002, an 8% increase for the current year. The increase in expenses for 2002 is due to 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 have all increased during 2002. Excluding the effect of the one-time charges during 2001, net general and administrative expenses reflects a corresponding increase of 10% from $11.9 million during 2001 to $13.1 million during 2002. The increase in overhead reimbursements during 2002 is due to an increase in the number of producing properties that we operate that have third party working interests. Capitalized general and administrative expenses increased slightly by 3% during 2002 as compared to 2001 as we capitalized approximately the same percentage of general and administrative expenses during both 2001 and 2002.

On an Mcfe basis, net general and administrative expenses decreased 32% from $0.19 per Mcfe during 2001 to $0.13 per Mcfe during 2002. Excluding the effect of the one-time charges taken in year of 2001 for the termination of employment contracts totaling $5.2 million, net general and administrative expenses on a per Mcfe basis would have remained unchanged at approximately $0.13 per Mcfe for both 2001 and 2002 with an increase in expense offset by an increase in production.

Other Income and Expense. For the year ended 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). During the year of 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. Interest expense, net of capitalized interest, increased 147% from $3.0 million during 2001 to $7.4 million for 2002. Aggregate interest expense increased by 3% from $15.0 during 2001 to $15.4 million during 2002. The increase in aggregate interest is due to a decrease in interest rates from an average borrowing rate of 7.43% during 2001 to an average borrowing rate of 5.38% during 2002 offset by an increase in our average borrowings from $190.9 million during 2001 to an average of $263.6 million for 2002. Capitalized interest decreased 33% from $12.0 million for 2001 to $8.0 million for 2002 and corresponds to the decrease in aggregate interest expense combined with 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 41% from $66.8 million for 2001 to $39.1 million for 2002 due to the 42% decrease in pre-tax income during 2002 from $189.4 million during 2001 to $109.6 million 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.

Operating Income and Net Income. Operating income decreased 44% from $192.5 million during 2001 to $107.9 million during 2002 as a result of a decrease in revenues caused by a 23% decrease in realized natural gas prices offset only in part by the 14% increase in production combined with a 21% increase in operating expenses. Corresponding to the decrease in operating income, net income decreased 42% from $122.6 million during 2001 to $70.5 million during 2002 and includes the effects of higher interest expense and lower taxes.

COMPARISON OF THE YEARS ENDED DECEMBER 31, 2001 AND 2000

Production. Our production increased 13% from 79,727 MMcfe for the year ended December 31, 2000 to 89,849 MMcfe for the year ended December 31, 2001. The increase in production was primarily attributable to newly developed offshore production brought on-line since the end of the second quarter of 2000.

Offshore, our production increased 30% from an average of 99 MMcfe/day during 2000 to an average of 129 MMcfe/day during 2001. This increase is primarily attributable to a full year of production at West Cameron 587, North Padre Island 883, Matagorda 704 and High Island 133/115 combined with newly developed production at Galveston Island 144, 190, 241 and 389, High Island 39 and East Cameron 83.

Onshore, our daily production rates decreased slightly by 2% from an average of 119 MMcfe/day during 2000 to an average of 117 MMcfe/day during 2001. The onshore production decrease is primarily attributable to a decline in production from our South Louisiana properties from an average of 11 MMcfe/day during 2000 to an average of 8 MMcfe/day during 2001 due primarily to natural reservoir decline. Average daily production from our Charco Field together with production from our Arkoma, East Texas and West Virginia properties remained unchanged at an average of 83 MMcfe/day and 26 MMcfe/day, respectively.

Natural Gas and Oil Revenues. Natural gas and oil revenues increased 40% from $277.5 million for the year ended December 31, 2000 to $387.2 million for the year ended December 31, 2001 as a result of a 26% increase in average realized natural gas prices, from $3.46 per Mcf in 2000 to $4.32 per Mcf in 2001, combined with a 13% increase in production for the same period.

Natural Gas Prices. As a result of hedging activities, we realized an average gas price of $4.32 per Mcf for the year ended December 31, 2001, which was 103% of the average unhedged natural gas price of $4.18 that we otherwise would have been received, resulting in natural gas and oil revenues for the year ended December 31, 2001 that were $12.9 million higher than the revenues we would have achieved if hedges had not been in place during the period. For the corresponding period during 2000, we realized an average gas price of $3.46 per Mcf, which was 85% of the average unhedged natural gas price of $4.05 that otherwise would have been received, resulting in natural gas and oil revenues that were $46.3 million lower than the revenues we would have achieved if hedges had not been in place during the period.

Lease Operating Expenses and Severance Tax. Lease operating expenses increased 7% from $23.6 million for the year ended December 31, 2000 to $25.3 million for the year ended December 31, 2001. On an Mcfe basis, lease operating expenses decreased from $0.30 per Mcfe during 2000 to $0.28 per Mcfe during 2001. The increase in lease operating expenses for 2001 is attributable to the continued expansion of our operations, primarily from the addition of four new offshore producing blocks during 2001 combined with a full year of operations from another four blocks brought on-line during the second half of 2000. We saw service costs increase during the first half 2001 and stabilize during the later half of the year which corresponded directly with the weakening of commodity prices and a slowdown in drilling activity across the industry. The decrease in lease operating expenses per Mcfe reflects the 13% increase in production volume during 2001 due primarily to newly developed offshore production. Severance tax, which is a function of volume and revenues generated from onshore production, increased from $9.8 million for the year ended December 31, 2000 to $11.0 million for the year ended December 31, 2001. On an Mcfe basis, severance tax remained unchanged at $0.12 per Mcfe for each of the years ended December 31, 2000 and 2001. The increase in severance tax expense reflects higher natural gas prices received during 2001 combined with newly developed offshore production located in state waters brought on-line during the year.

Transportation Expense. We applied Emerging Issues Task Force ("EITF") No. 00-10 "Accounting for Shipping and Handling Fees and Costs" for all periods presented. Pursuant to our application of EITF No. 00-10, transportation expense previously reflected as a reduction of natural gas and oil revenues were added back to the related revenues and reclassified as a separate component of operating expense. For the years ended December 31, 2001 and 2000, natural gas and oil revenues, total revenues, transportation expense and total operating expenses were restated and reclassified, respectively. The application of EITF No. 00-10 had no effect on operating income or net income. See Note 11 - Restatement and Reclassification made to Consolidated Statements of Operations for Transportation Expense. Transportation expense increased 12% from $6.9 million and $0.09 per Mcfe in 2000 to $7.7 million and $0.09 per Mcfe during 2001. The increase in expense corresponds to the 13% increase in total production for 2001.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased 44% from $89.2 million for the year ended December 31, 2000 to $128.7 million for the year ended December 31, 2001. Depreciation, depletion and amortization expense per Mcfe increased 28% from $1.12 during 2000 to $1.43 during 2001. The increase in depreciation, depletion and amortization expense was a result of higher production volumes combined with a higher depletion rate. The higher depletion rate is primarily a result of a higher level of capital spending during 2001 as compared to 2000 combined with the addition of fewer new reserves in 2001 from exploration and developmental drilling.

Writedown in Carrying Value of Natural Gas and Oil Properties. At December 31, 2001, we were required under full cost accounting rules to write down the carrying value of our full cost pool primarily as a result of weak natural gas prices. In calculating the ceiling test, we estimated, using a December 31, 2001 wellhead price of $2.38 per Mcf, that our capitalized costs exceeded the ceiling limitation by $6.2 million and accordingly we recorded a writedown of our full cost pool and a charge to earnings during the fourth quarter of $4.0 million, net of tax.

General and Administrative Expenses. General and administrative expenses, net of overhead reimbursements received from other working interest owners, of $3.6 million and $1.2 million for the years ended December 31, 2000 and 2001, respectively, increased 92% from $8.9 million for the year ended December 31, 2000 to $17.1 million for the year ended December 31, 2001. Included in reimbursements received from working interest owners were reimbursements totaling $2.5 million during 2000 received from KeySpan pursuant to our joint drilling venture with KeySpan (see Note 6 -- Related Party Transactions). Overhead reimbursements were terminated December 31, 2000 with the expiration of the initial exploratory term of our joint drilling venture with KeySpan, and as a result we no longer receive reimbursement of general and administrative expenses from KeySpan. We capitalized general and administrative expenses directly related to oil and gas exploration and development activities of $9.6 million and $12.8 million, respectively, for the years ended December 31, 2000 and 2001. The increase in capitalized general and administrative expenses is a result of higher aggregate general and administrative expenses during 2001. Aggregate general and administrative expenses were higher during 2001 as a result of: (i) one-time payments totaling $5.2 million in connection with the termination of former executive officers' employment contracts; (ii) expansion of our workforce; and (iii) an increase in incentive compensation and benefit related expenses.

On an Mcfe basis, general and administrative expenses increased 73% from $0.11 during 2000 to $0.19 during 2001. Excluding the one-time charges taken for the termination of employment contracts totaling $5.2 million, general and administrative expenses on a per Mcfe basis would have increased 18% from $0.11 for 2000 to $0.13 for 2001. The higher rate per Mcfe during 2001 reflects the increase in aggregate general and administrative expenses caused by the effects of the termination of reimbursements received pursuant to our joint drilling venture with KeySpan which totaled $2.5 million during 2000 combined with the expansion of the Company's workforce and higher incentive compensation and benefit related expenses.

Interest Expense, Net. Interest expense, net of capitalized interest, decreased 74% from $11.4 million for the year ended December 31, 2000 to $3.0 million for the year ended December 31, 2001. Aggregate interest expense decreased 40% from $25.1 during 2000 to $15.0 million during 2001. The decrease in aggregate interest is due to a decrease in interest rates combined with (i) the repayment of $85 million in borrowings under the revolving bank credit facility during the first nine months of 2001; and (ii) the March 31, 2000 conversion of $80 million in outstanding borrowings under a revolving credit facility with KeySpan into 5,085,177 shares of our common stock (see Note 3 -- Stockholders' Equity - KeySpan Credit Facility and Conversion). Capitalized interest decreased 12% from $13.7 million during 2000 to $12.0 million during 2001 and reflects the decrease in aggregate interest expense offset in part by a higher level of exploratory drilling during 2001 Our capitalized interest is a function of exploratory drilling and unevaluated properties. Interest rates on our total outstanding borrowings averaged 7.43% during 2001 compared to 8.07% in 2000.

Income Tax Provision. The provision for income taxes increased from $42.5 million for the year ended December 31, 2000 to $66.8 million for the year ended December 31, 2001 due to the 48% increase in pre-tax income during 2001 from

$127.7 million during 2000 to $189.4 million during 2001 as a result of the combination of higher natural gas prices, an increase in production, a decrease in interest expense offset in part by an increase in operating expenses.

Operating Income and Net Income. For the year ended December 31, 2001, the 26% increase in natural gas prices combined with the 13% increase in production, offset in part by a 43% increase in operating expenses, caused operating income to increase 37% from $140.9 million during 2000 to $192.5 million during 2001. Correspondingly, net income increased 44% from $85.3 million for 2000 to $122.6 million for 2001 and reflects lower interest expense and higher taxes.

LIQUIDITY AND CAPITAL RESOURCES

We currently fund our operations, acquisitions, capital expenditures and working capital requirements from cash flows from operations, public debt and bank borrowings. We believe cash flows from operations and borrowings under our revolving bank credit facility will be sufficient to fund our planned capital expenditures and operating expenses during 2003.

Cash Flows. As of December 31, 2002, we had a working capital deficit of $1.7 million and $147.6 million of borrowing capacity available under our revolving bank credit facility. The working capital deficit is due to the classification as a current liability of $35.0 million relating to the current portion of the fair market value of our derivative instruments. Net cash provided by operating activities for 2002 was $243.9 million compared to $358.0 million during 2001. The decrease in net cash provided by operating activities was due to (i) a decrease in 2002 net income caused primarily by lower realized natural gas prices, offset in part by an increase in production volumes during the current year combined with (ii) a net increase in current assets and current liabilities at year end 2002 which is related to the timing of cash receipts and payments. For 2002, the increase in current assets was caused primarily by an increase in receivables at the end of 2002 due to higher gas prices and production volumes for the fourth quarter of 2002 as compared to the corresponding period of 2001. Current liabilities (excluding the fair value of derivatives which is a non-cash item) increased due to a higher level of drilling activity in the fourth quarter of 2002 as compared to the fourth quarter of 2001. For the year of 2002, funds used in investing activities consisted of $252.1 million for net cash investments in property and equipment, which compares to $368.3 million spent during 2001. Our cash position increased during 2002 as a result of net borrowings under our revolving bank credit facility of $8 million compared to repayments totaling $1 million during 2001. Cash increased by $9.7 million and $10.2 million, respectively, during 2002 and 2001 due to proceeds received from the issuance of common stock from the exercise of stock options. As a result of these activities, cash and cash equivalents increased $9.4 million from $8.6 million at December 31, 2001 to $18.0 million at December 31, 2002.

Investments in Property and Equipment. During the year of 2002, we invested $258.4 million in natural gas and oil properties and $2.4 million for other property and equipment, which includes the expansion of our Houston office space together with upgrades to our information technology systems and equipment. The table below summarizes our natural gas and oil expenditures and our average "all-in" finding and development cost on an equivalent Mcf basis. Leasehold acquisition costs include among other things, costs incurred for seismic, capitalized interest and capitalized general and administrative costs. During 2002, 2001, 2000, 1999 and 1998, we capitalized a total of $21.1 million, $24.9 million, $23.3 million, $17.4 million and $17.3 million respectively, in capitalized interest and general and administrative expenses which amounts are included in the line item "Leasehold and Lease Acquisition Costs" in the table below. During 2002 we sold non-core natural gas and oil assets for a total of $5.3 million, of which $5.0 million related to the sale of the McFarlan and Maude Traylor Fields purchased in May 2002 as part of the group of properties acquired from Burlington Resources (see Notes to Consolidated Financial Statements, Note 10 - Acquisitions - Burlington Acquisition).

YEARS ENDED DECEMBE
(IN THOUSANDS, EXCEPT PER

	2002	2001	2000
Natural gas and oil capital expenditures			
Producing property acquisitions (1)	$ 68,042	$ 69,010	$ 13,935
Leasehold and lease acquisition costs	36,458	48,068	32,599
Development	122,036	177,256	103,335
Exploration	26,536	72,056	34,160
Total natural gas and oil capital expenditures	$ 253,072	$ 366,390	$ 184,029
Proved reserve additions (MMcfe)	144,291	136,231	100,352
Finding and development cost per Mcfe	$ 1.75	$ 2.69	$ 1.83

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(1) For the year ended December 31, 2002, producing property acquisitions is net of dispositions of $5.3 million.

Future Capital Requirements. Our capital expenditure budget for 2003 is $286 million. This amount includes an estimated $72 million for exploration, $193 million for development and facility construction and $21 million for leasehold acquisition costs, which includes seismic, capitalized interest and general and administrative expenses. We do not include property acquisition costs in our capital expenditure budget because the size and timing of capital requirements for acquisitions are inherently unpredictable. The capital expenditure budget includes exploration and development costs associated with projects in progress or planned for the upcoming year and amounts are contingent upon drilling success. No significant abandonment or dismantlement costs are anticipated in 2003. No assurances can be made that amounts budgeted will equal actual amounts spent. We will continue to evaluate our capital spending plans throughout the year. Actual levels of capital expenditures may vary significantly due to a variety of factors, including drilling results, natural gas prices, industry conditions and outlook and future acquisitions of properties. We believe cash flows from operations and borrowings under our credit facility will be sufficient to fund these expenditures. We intend to continue to selectively seek acquisition opportunities for proved reserves with substantial exploration and development potential both offshore and onshore although we may not be able to identify and make acquisitions of proved reserves on terms we consider favorable.

Capital Structure

Revolving Bank Credit Facility. We entered into a new revolving bank credit facility, dated as of July 15, 2002, 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 new credit facility replaced our previous $250 million revolving bank credit facility, and provides us with an initial commitment of $300 million (for description of our previous revolving bank credit facility, see Note 2 - Long-term Debt and Notes.) The initial $300 million commitment 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 new credit facility is subject to borrowing base limitations; and our borrowing base has been set at $300 million. Our borrowing base will be redetermined semi-annually, with the next redetermination scheduled for April 1, 2003. Up to $25 million of the borrowing base is available for the issuance of letters of credit. The new credit facility matures July 15, 2005, is unsecured and with the exception of trade payables, ranks senior to all of our existing debt.

At December 31, 2002, outstanding borrowings under our revolving bank credit facility were $152 million together with $0.4 million in outstanding letter of credit obligations. Subsequent to December 31, 2002, we repaid a net $6 million under the facility. At February 20, 2003, outstanding borrowings and letter of credit obligations under our revolving bank credit facility totaled $147.4 million.

Senior Subordinated Notes. On March 2, 1998, we issued $100 million of 8?% Senior Subordinated Notes due January 1, 2008. The notes bear interest at a rate of 8?% per annum with interest payable semi-annually on January 1 and July 1. We may redeem the notes 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 which decreases yearly from 4.313% in 2003 to 0% in 2006. 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, if any. The notes are general unsecured obligations and rank subordinate in right of payment to all existing and future senior debt, including the credit facility, and will rank senior or equal in right of payment to all existing and future subordinated indebtedness.

Contractual Obligations and Other Commercial Commitments

The table below summarizes our contractual obligations and commercial commitments at December 31, 2002. We have no "off-balance sheet" financing arrangements.

	AT DECEMBER 31, 2002		
	PAYMENTS DUE BY PERIOD		
CONTRACTUAL OBLIGATIONS	1 - 3 YEARS	4 - 5 YEARS	AFTER 5 YEARS
		(IN THOUSANDS)	
Revolving bank credit facility	$ 152,000	$ --	$ --
8 5/8% senior subordinated notes	--	--	100,000
Operating leases	3,363	2,331	3,323
Section 29 tax credit repurchase	2,000	--	--
Total contractual obligations	$ 157,363	$ 2,331	$ 103,323

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. Historically, we have not experienced credit losses. 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.

During the fourth quarter of 2002, an increase in forward market prices for natural gas caused our mark-to-market exposure with one counter party to surpass our contractual margin threshold as established under the contract. As a result, we were required to post margin in the amount of $5.4 million. The margin payment earns interest at a market rate and will be refunded if our mark-to-market exposure drops below the margin threshold as required under the contract. This will occur if market prices decline from current levels. At December 31, 2003, the $5.4 million paid for the margin call is classified as restricted cash and is included in current assets on the balance sheet in the line item "Prepayments and Other." Subsequent to December 31, 2002, our margin was increased by $5.9 million to a balance of $11.3 million at February 20, 2003.

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.

CHANGES IN FAIR VALUE OF DERIVATIVE INSTRUMENTS

The following table summarizes the change in the fair value of our derivative instruments for the twelve month period from January 1 to December 31, 2002 and 2001, respectively. Stated amounts do not reflect the effects of taxes.

CHANGE IN FAIR VALUE OF DERIVATIVES INSTRUMENTS	2002	2001
	(IN THOUSANDS)	

Fair value of contracts at January 1	$ 53,771	$ (75,069)
(Gain) loss on contracts realized	(16,358)	(12,926)
Fair value of new contracts when entered into during period	--	5,931
(Decrease) increase in fair value of all open contracts	(76,185)	135,835
Fair value of contracts outstanding at December 31	$ (38,772)	$ 53,771

DERIVATIVES IN PLACE AS OF THE DATE OF OUR REPORT

Oil. We entered into an oil swap as described in the following table. All amounts are in thousands, except for prices. The swap covers the first six months of 2003 for 1,000 barrels per day with a contract price of $28.50 for months January through March and $29.70 for months April through June.

	FIXED PRICE SWAPS		COLLARS		
PERIOD	VOLUME (MBbl)	NYMEX CONTRACT PRICE	VOLUME (MBbl)	NYMEX CONTRACT PRICE AVG FLOOR	AVG CEILING
January 2003	31	$ 28.50	--	--	--
February 2003	28	28.50	--	--	--
March 2003	31	28.50	--	--	--
April 2003	30	29.70	--	--	--
May 2003	31	29.70	--	--	--
June 2003	30	29.70	--	--	--

Natural Gas. The following table summarizes, on a monthly basis, our hedges currently in place for 2003 and 2004. All amounts are in thousands, except for prices. For the first three months of 2003, we have 185,000 MMBtu/day hedged at an effective floor of $3.428 and an effective ceiling of $4.574. For the remaining nine months of 2003, we have 190,000 MMBtu/day hedged at an effective floor of $3.417 and an effective ceiling of $4.548. For each month during 2004, we have 100,000 MMBtu/day hedged at a floor of $3.750 and a ceiling of $5.045.

	FIXED PRICE SWAPS		COLLARS	
	VOLUME	NYMEX CONTRACT	VOLUME	NYMEX CONTRACT PRICE

PERIOD	(MMbtu)	PRICE	(MMbtu)	AVG FLOOR	AVG CEILING
January 2003	1,240	$ 3.194	4,495	$ 3.493	$ 4.954
February 2003	1,120	3.194	4,060	3.493	4.954
March 2003	1,240	3.194	4,495	3.493	4.954
April 2003	1,200	3.194	4,500	3.476	4.909
May 2003	1,240	3.194	4,650	3.476	4.909
June 2003	1,200	3.194	4,500	3.476	4.909
July 2003	1,240	3.194	4,650	3.476	4.909
August 2003	1,240	3.194	4,650	3.476	4.909
September 2003	1,200	3.194	4,500	3.476	4.909
October 2003	1,240	3.194	4,650	3.476	4.909
November 2003	1,200	3.194	4,500	3.476	4.909
December 2003	1,200	3.194	4,650	3.476	4.909
January 2004	--	--	3,100	3.750	5.045
February 2004	--	--	2,900	3.750	5.045
March 2004	--	--	3,100	3.750	5.045
April 2004	--	--	3,000	3.750	5.045
May 2004	--	--	3,100	3.750	5.045
June 2004	--	--	3,000	3.750	5.045
July 2004	--	--	3,100	3.750	5.045
August 2004	--	--	3,100	3.750	5.045
September 2004	--	--	3,000	3.750	5.045
October 2004	--	--	3,100	3.750	5.045
November 2004	--	--	3,000	3.750	5.045
December 2004	--	--	3,100	3.750	5.045

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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

The financial statements required by this item are incorporated under Item 14 in Part IV of this report.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

On March 29, 2002, our Board of Directors, upon recommendation of the Audit Committee, resolved not to renew the engagement of our independent public accountants, Arthur Andersen LLP and to appoint Deloitte & Touche LLP as independent public accountants.

The audit reports of Arthur Andersen on the consolidated financial statements of our company as of and for the fiscal years ended December 31, 2000 and 2001 did not contain any adverse opinion or disclaimer of opinion, nor were they qualified or modified as to uncertainty, audit scope or accounting principles.

During the two fiscal years ended December 31, 2001, and the subsequent interim period through March 29, 2002, there were no disagreements with Arthur Andersen on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreements, if not resolved to Arthur Andersen's satisfaction, would have caused Arthur Andersen to make reference to the subject matter of the disagreement in connection with its reports.

None of the reportable events described under Item 304(a)(1)(v) of Regulation S-K occurred within the fiscal years ended December 31, 2001 or within the interim period through March 29, 2002.

We provided Andersen with a copy of the above disclosures. A letter dated April 5, 2002, from Arthur Andersen stating its agreement with our statements was listed under Item 7 and filed as Exhibit 16.1 and incorporated by reference into our report on Form 8-K filed March 29, 2002.

During the two fiscal years ended December 31, 2001 and 2000, and the subsequent interim period through March 29, 2002, we did not consult with Deloitte & Touche regarding any of the matters or events set forth in Item 304(a)(2)(i) and (ii) of Regulation S-K.

PART III.

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

EXECUTIVE OFFICERS

The names and backgrounds of each of our executive officers are set forth below.

NAME	AGE	WITH US SINCE	
William G. Hargett	53	2001	President and Chief
Charles W. Adcock	49	1996	Senior Vice Preside Offshore Divisio
John H. Karnes	43	2002	Senior Vice Preside Officer
Steven L. Mueller	49	2001	Senior Vice Preside Onshore Division
Tracy Price	44	2001	Senior Vice Preside
Roger B. Rice	58	2002	Vice President - Hu Administration
Thomas E. Schwartz	46	1990	Vice President - Ge
James F. Westmoreland	47	1986	Vice President, Chi Secretary

William G. Hargett was appointed President and Chief Executive Officer and a Director on April 4, 2001. Immediately prior to joining Houston Exploration and from September 2000 to March 2001, Mr. Hargett was a private investor. From May 5, 1999 until August 29, 2000, Mr. Hargett was President-North America of Santa Fe Snyder Corporation. Prior to that he was President and Chief Operating Officer and a director of Snyder Oil Corporation. Prior to joining Snyder Oil Corporation in April of 1997, Mr. Hargett served as President of Greenhill Petroleum Corporation, the U.S. oil and gas subsidiary of Australian-based Western Mining Corporation from 1994 to 1997, Amax Oil & Gas, Inc. from 1993 to 1994 and North Central Oil Corporation from 1988 to 1993. Mr. Hargett was employed in various exploration capacities by Tenneco Oil Corporation from 1974 to 1988 and Amoco Production Company from 1973 to 1974. Mr. Hargett earned a B.S. and an M.S. from the University of Alabama.

Charles W. Adcock was appointed Senior Vice President and General Manager - Offshore Division effective October 1, 2001. From April 2000 to October 2001, Mr. Adcock served as Senior Vice President - Operations and Engineering. Mr. Adcock held the position of Vice President--Project Development from September 1996 until April 2000. Mr. Adcock held the same position, Vice President--Project Development, with Fuel Resources, Inc., a subsidiary of Brooklyn Union that previously owned our onshore properties, from 1993 to 1996. Prior to joining Fuel Resources, Inc., Mr. Adcock worked at NERCO Oil & Gas as Reservoir Engineering Specialist. Prior to NERCO, he held various engineering positions with Apache, ANR Production and Aminoil U.S.A. Mr. Adcock is a Registered Professional Engineer in the State of Texas, and received his B.S. in Civil Engineering from Texas A&M University and an M.B.A. from the University of St. Thomas.

John H. Karnes was appointed Senior Vice President and Chief Financial Officer effective November 18, 2002. Immediately prior to joining Houston Exploration, Mr. Karnes was Vice President and General Counsel for Encore Acquisition Company of Fort Worth, Texas since January 2002. During 2000 and 2001, Mr. Karnes was Executive Vice President and Chief Financial Officer of CyberCash, Inc., an internet payment software and services provider. Mr. Karnes also served as Chief Operating Officer of CyberCash during the break up and sale of its operating divisions through a pre-packaged Chapter 11 bankruptcy proceeding in 2001. Mr. Karnes was Vice President and General Counsel of Snyder Oil Corporation, an independent oil and gas exploration and production company, during 1998 and 1999. Prior to joining Snyder in 1998, Mr. Karnes was Divisional President/Corporate Senior Vice President at FIRSTPlus Financial Corporation, a consumer finance and mortgage company. Mr. Karnes has Juris Doctorate from Southern Methodist University School of Law and a Bachelor in Business Administration - Accounting from the University of Texas at Austin.

Steven L. Mueller was appointed to the newly created position of Senior Vice President and General Manager - Onshore Division effective October 22, 2001. Immediately prior to joining Houston Exploration, Mr. Mueller had been Senior Vice President - Exploration and Production for Belco Oil and Gas Corp. Mr. Mueller joined Belco Oil and Gas Corp. in 1996 and held various senior management positions involving oil and gas exploration. From 1992 to 1996 Mr. Mueller was Exploitation Vice President for American Exploration Company. From 1988 to 1992, Mr. Mueller was Exploration Manager - South Louisiana for Fina Oil and Chemical Company. Mr. Mueller began his career with Tenneco Oil Corporation in 1975 and held various geological and engineering positions with Tenneco from 1975 to 1988. Mr. Mueller received his B.S. in Geological Engineering from the Colorado School of Mines in 1975.

Tracy Price was appointed Senior Vice President - Land effective July 16, 2001. Immediately prior to joining Houston Exploration, Mr. Price had been Manager of Land and Business Development for Newfield Exploration Company since September 1990. From 1986 to 1990, Mr. Price was Land Manager with Apache Corporation. Prior to joining Apache Corporation, Mr. Price served as Senior Landman for Challenger Minerals Inc. from 1983 to 1986 and worked as a landman for Phillips Petroleum Company from 1981 to 1983. He received his B.B.A. in Petroleum Land Management from The University of Texas.

Roger B. Rice was appointed to the newly created position of Vice President - Human Resources and Administration effective March 1, 2002. Mr. Rice worked as a paid consultant for Houston Exploration since June 2001. From January 2001 to June 2001, Mr. Rice was a private management consultant and oil and gas investor. From December 1999 to December 2000, Mr. Rice was Vice President and General Manager for Santa Fe Snyder Corporation where he was responsible for all onshore exploration and production activities in Texas and New Mexico. Mr. Rice had been Vice President - Human Resources with Snyder Oil Corporation from 1997 until its merger with Santa Fe Resources in 1999. From 1992 to 1997, Mr. Rice was Vice President Human Resources and Administration with Apache Corporation. From 1989 to 1992, he was Managing Consultant with Barton Raben, Inc., an executive search and consulting firm specializing in the energy industry. Previously, Mr. Rice was Vice President Administration for The Superior Oil Company and held various management positions with Shell Oil Company. He earned his B.A. and M.B.A. from Texas Technological University.

Thomas E. Schwartz has been Vice President - Geophysics since May 1998. Prior to his appointment to Vice President, Mr. Schwartz was a senior offshore geophysicist for us from 1990 to 1998. From 1984 until 1990, Mr. Schwartz held the positions of senior geologist and senior geophysicist for Sonat Exploration Company. Prior to joining Sonat Exploration Company, he was an explorationist with Eason Oil Company from 1980 to 1984. Mr. Schwartz received his B.S. in Geology from the University of New Orleans.

James F. Westmoreland has been Vice President, Chief Accounting Officer and Secretary since October 1995 and was Vice President and Comptroller from 1986 to 1995. Mr. Westmoreland was supervisor of natural gas and oil accounting at Seagull from 1983 to 1986. Mr. Westmoreland holds a B.B.A. in Accounting from the University of Houston.

BOARD OF DIRECTORS

The names and principal occupations of each of the members of our Board of Directors are set for below.

NAME	AGE	DIRECTOR SINCE	
Robert B. Catell	66	1986	Chairman of the Board
Gordon F. Ahalt	75	1996	Director
David G. Elkins	61	1999	Director
Robert J. Fani	49	2002	Director
William G. Hargett	53	2001	Director
Harold R. Logan, Jr.	58	2002	Director
Gerald Luterman	59	2000	Director
H. Neil Nichols	65	2000	Director
James Q. Riordan	75	1996	Director
Donald C. Vaughn	67	1997	Director

Robert B. Catell has been Chairman of the Board of Directors since 1986. Mr. Catell is the Chairman and Chief Executive Officer of KeySpan Corporation, a diversified energy provider, and has held this position since July 1998. KeySpan owns approximately 67% of the shares our common stock. Mr. Catell joined KeySpan's subsidiary, The Brooklyn Union Gas Company, in 1958 and was elected Assistant Vice President in 1974, Vice President in 1977, Senior Vice President in 1981 and Executive Vice President in 1984. Mr. Catell was elected Brooklyn Union's Chief Operating Officer in 1986 and President in 1990. Mr. Catell served as President and Chief Executive Officer of Brooklyn Union from 1991 to 1996 when he was elected Chairman and Chief Executive Officer and held these positions until the formation of KeySpan in May 1998 through the combination of Brooklyn Union's parent company, KeySpan Energy Corporation, and certain assets of Long Island Lighting Company. Mr. Catell serves on the Boards of Alberta Northeast Gas, Ltd., Boundary Gas Inc., Taylor Gas Liquids Fund, Ltd., Gas Technology Institute, Edison Electric Institute, New York State Energy Research and Development Authority, Independence Community Bank Corp., Business Council of New York State, Inc., New York City Investment Fund, New York City Partnership and the Long Island Association. Mr. Catell received both his Bachelor's and Master's Degrees in Mechanical Engineering from City College of New York. He holds a Professional Engineer's License in New York State, and attended Columbia University's Executive Development Program and Harvard Business School's Advanced Management Program.

Gordon F. Ahalt has been a Director since 1996. Mr. Ahalt has been President of G.F.A. Inc., a petroleum industry financial and management consulting firm, since 1982. Mr. Ahalt was a consultant to Brooklyn Union until May 1998. He was most recently a consultant to W.H. Reaves Co., Inc., an asset manager specializing in large cap petroleum, public utilities and telecommunication equities. Mr. Ahalt serves as a Director for the Bancroft and Ellsworth Convertible Funds, which specializes in convertible bond and debenture funds, and Cal Dive International, an offshore oil field service company that provides subsea construction, inspection, maintenance, repair and salvage services. Mr. Ahalt received a B.S. in Petroleum Engineering in 1951 from the

University of Pittsburgh, attended New York University's Business School and is a graduate of Harvard Business School's Advanced Management Program. He worked for Amoco Corporation from 1951 to 1955, Chase Manhattan Bank from 1955 to 1972, White Weld & Co., Inc. from 1972 to 1973, and Chase Manhattan Bank from 1974 through 1976, and served as President and Chief Executive Officer of International Energy Bank London from 1977 through 1979 and as Chief Financial Officer of Ashland Oil Inc. from 1980 through 1981.

David G. Elkins has been a director since July 27, 1999. In January of 2003, Mr. Elkins retired as President and Co-CEO of Sterling Chemicals, Inc., a chemicals producing company. Sterling Chemicals commenced voluntary reorganization proceedings under Chapter 11 of the Bankruptcy Code in July 2001 and successfully emerged in December 2002. Prior to joining Sterling Chemicals in 1998, Mr. Elkins was a senior partner in the law firm of Andrews & Kurth L.L.P. where he specialized in corporate and business law, including mergers and acquisitions, securities law matters and corporate governance matters. Mr. Elkins serves as a director of Sterling Chemicals, Inc., Guilford Mills, Inc. and Memorial Hermann Hospital System. He received his J.D. degree from Southern Methodist University in 1968.

Robert J. Fani was elected to our Board of Directors in May 2002. Mr. Fani was elected President -Energy Assets and Supply of KeySpan in 2003. Mr. Fani joined KeySpan's subsidiary, The Brooklyn Union Gas Company, in 1976 and has held a variety of management positions. Prior to his election as President of KeySpan Energy Assets and Supply, he was President of Energy Services and Supply since July 2001. Prior to that he was Executive Vice President Strategic Services. From 1996 to 2000, he was Senior Vice President, Marketing and Sales/Strategic Marketing. Currently, Mr. Fani oversees KeySpan's electric services business unit, its gas supply and energy management group, as well as its asset management and development group. Mr. Fani is a trustee with City College of New York and Neighborhood Housing Association. Mr. Fani received a B.S. in mechanical engineering from City College of New York in 1976, an M.B.A. from St. John's University in 1982 and a J.D. from New York Law School in 1986.

William G. Hargett was appointed President and Chief Executive Officer and a Director on April 4, 2001. From May 5, 1999 until August 29, 2000, Mr. Hargett was President-North America of Santa Fe Snyder Corporation. Prior to that he was President and Chief Operating Officer and a director of Snyder Oil Corporation. Prior to joining Snyder Oil Corporation in April of 1997, Mr. Hargett served as President of Greenhill Petroleum Corporation, the U.S. oil and gas subsidiary of Australian-based Western Mining Corporation from 1994 to 1997, Amax Oil & Gas, Inc. from 1993 to 1994 and North Central Oil Corporation from 1988 to 1993. Mr. Hargett was employed in various exploration capacities by Tenneco Oil Corporation from 1974 to 1988 and Amoco Production Company from 1973 to 1974. Mr. Hargett earned a B.S. and an M.S. from the University of Alabama.

Harold R. Logan, Jr., was appointed to our Board of Directors on December 20, 2002. Mr. Logan is presently Director and Chairman of the Finance Committee of the Board of Directors of TransMontaigne, Inc. and from 1995 through 2002 he was the Chief Financial Officer, Executive Vice President and Treasurer and a Director of TransMontaigne. From 1985 to 1994, Mr. Logan was Senior Vice President/Finance and a Director of Associated Natural Gas Corporation. Prior to joining Associated Natural Gas Corporation, Mr. Logan was with Dillon, Read & Co. Inc. and Rothschild, Inc. In addition, Mr. Logan is a Director of Suburban Propane Partners, L.P., Graphic Packaging Corporation, and Rivington Capital Advisors LLC. Mr. Logan received a B.S. in Economics from Oklahoma State

University and an M.B.A. - Finance from Columbia University Graduate School of Business.

Gerald Luterman has been a Director since May 2000. Mr. Luterman is Executive Vice President and Chief Financial Officer of KeySpan. He joined KeySpan in August 1999 as Senior Vice President and Chief Financial Officer. Prior to being appointed to his position at KeySpan, Mr. Luterman was the Chief Financial Officer of barnesandnoble.com, an internet bookstore, from February 1999 to August 1999; the Senior Vice President and Chief Financial Officer of Arrow Electronics, Inc., a distributor of electronic components and computer products, from April 1996 to February 1999. Prior to that, from 1985 to 1996, Mr. Luterman held executive positions with American Express, including Executive Vice President and Chief Financial Officer of the Consumer Card Division from 1991 to 1996. Mr. Luterman is a Canadian Chartered Accountant and received an MBA from Harvard Business School.

H. Neil Nichols has been a Director since May 2000. Mr. Nichols is Senior Vice President of Corporate Development and Asset Management for KeySpan and has held this position since March 1999. Mr. Nichols also serves as President of KeySpan Energy Development Corporation, a subsidiary of KeySpan, a position to which he was elected in March 1998. Prior to joining KeySpan in 1997, Mr. Nichols was an owner and President of Corrosion Interventions Ltd., a company based in Toronto, Canada, from 1996 to 1997 and Chairman, President, and Chief Executive Officer of Battery Technologies, Inc., from 1993 to 1995. Mr. Nichols began his career in the natural gas industry with TransCanada PipeLines Limited in 1956 and held various development positions until 1973 at which time he became Treasurer of TransCanada, serving as Treasurer until 1977. From 1977 to 1981, Mr. Nichols was Vice President of Finance and Treasurer of TransCanada, Senior Vice President of Finance from 1981 to 1983, Senior Vice President of Finance and Chief Financial Officer from 1983 to 1988 and Executive Vice President from 1988 to 1989. Mr. Nichols currently is a director of various KeySpan subsidiaries and is a member of the Board of Directors of Taylor Gas Liquids and KeySpan Energy Canada. Mr. Nichols is a Certified Management Accountant and a member of the Financial Executives Institute.

James Q. Riordan has been a Director since 1996 and was a Director of KeySpan from May 1998 until his retirement in May 2002. Mr. Riordan is the retired Vice Chairman and Chief Financial Officer of Mobil Corp. He joined Mobil Corp. in 1957 as Tax Counsel and was named Director and Chief Financial Officer in 1969. Mr. Riordan served as Vice Chairman of Mobil Corp. from 1986 until his retirement in 1989. He joined Bekaert Corporation in 1989 and was elected its President, and served as President until his retirement in 1992. Mr. Riordan is a Director of Tri-Continental Corporation; Director/Trustee of the mutual funds in the Seligman Group of investment companies; Trustee for the Committee for Economic Development and The Brooklyn Museum; and Member of the Policy Council of the Tax Foundation.

Donald C. Vaughn has been a Director since 1997 and is retired Vice Chairman of Halliburton Company, an oilfield services company, where he served in that capacity from the time Dresser Industries, Inc. merged with Halliburton in 1998 until his retirement on March 31, 2001. Prior to the merger, Mr. Vaughn was President, Chief Operating Officer and member of the board of directors of Dresser starting in 1996. Prior to his appointment as President and Chief Operating Officer of Dresser, Mr. Vaughn served as Executive Vice President of Dresser, responsible for Dresser's Petroleum Products and Services and

Engineering Services Segment, from November 1995 to December 1996; Senior Vice President of Operations of Dresser from January 1992 to November 1995; and Chairman, President and Chief Executive Officer of The M.W. Kellogg Company, an international engineering and construction company, from November 1983 to June 1996. Mr. Vaughn joined M.W. Kellogg in 1958 and is a registered professional engineer in the State of Texas. He has been recognized as a distinguished engineering alumnus of Virginia Polytechnic Institute, from which he holds a B.S. in civil engineering. Mr. Vaughn serves as a director of SHAWCOR Ltd., a publicly traded Canadian oil service company.

COMPLIANCE WITH SECTION 16(a)

Section 16(a) of the Exchange Act requires our directors and officers, and persons who own more than 10% of the common stock, to file initial reports of ownership and reports of changes in ownership of common stock on Forms 3, 4, and 5 with the Securities and Exchange Commission and the New York Stock Exchange. Officers, directors and greater than 10% stockholders are required by Securities and Exchange Commission regulations to furnish us with copies of any forms that they file. Based solely on a review of the forms submitted to the Company, it appears that there was no person subject to the reporting requirements of Section 16 of the Exchange Act that filed to file on a timely basis reports required under Section 16.

ITEM 11. EXECUTIVE COMPENSATION

COMPENSATION OF DIRECTORS

We pay each outside Director a fee of $5,000 per calendar quarter and $1,000 per board meeting and $1,000 per committee meeting attended. We pay chairmen of committees of our Board of Directors an additional fee of $500 per committee meeting. These fees are payable in cash or, at the option of the Director, may be deferred in an unfunded phantom stock or interest-bearing account, pursuant to our Deferred Compensation Plan for Non-Employee Directors.

In addition to these fees, each person who becomes a non-employee Director receives an option to purchase 5,000 shares of our common stock on the date of his or her election to the Board. On September 20 of each year, or the next following business day, we grant to each non-employee Director a non-qualified option to purchase 2,000 shares of our common stock. Options granted to Non-Employee Directors fully vest and become exercisable on the date of grant.

SUMMARY COMPENSATION TABLE

The following table sets forth summary information concerning the compensation we paid or accrued during each of the last three fiscal years to our Chief Executive Officer and each of our four other most highly compensated executive officers (collectively, the "Named Executive Officers"):

				LONG-TERM	
		ANNUAL COMPENSATION(1)		RESTRICTED STOCK	SECUR UNDER
NAME AND PRINCIPAL POSITION	YEAR	SALARY($)	BONUS($)	AWARDS($)(2)	OPTION

William G. Hargett......................	2002	$ 433,000	$ 306,000	$ --	
President and Chief Executive Officer	2001	299,000	321,100	256,000	1
	2000	--	--	--	
Charles W. Adcock.......................	2002	235,000	131,000	--	
Senior Vice President and General	2001	213,000	304,000	--	
Manager--Offshore Division	2000	192,000	173,000	--	
Steven L. Mueller.......................	2002	$ 235,000	$ 131,000	--	
Senior Vice President and General	2001	45,000	27,000	--	
Manager -- Onshore Division	2000	--	--	--	
Thomas E. Schwartz......................	2002	$ 202,000	$ 135,000	--	
Vice President - Geophysics	2001	193,000	286,000	--	
	2000	179,000	162,000	--	
James F. Westmoreland...................	2002	$ 203,000	$ 123,000	--	
Vice President, Chief Accounting	2001	193,000	286,000	--	
Officer and Secretary	2000	179,000	162,000	--	

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(1) Annual compensation amounts exclude perquisites and other personal benefits because the compensation did not exceed the lesser of $50,000 or 10% of the total annual salary and bonus reported for each Named Executive Officer.

Bonus amounts for 2000 include a special bonus of 15% of base salary paid in April 2000 pursuant to the conclusion and termination of the strategic review process we initiated in September 1999 (see Review of Strategic Alternatives on page 49 and in Note 6 - Related Party Transactions - Transactions with KeySpan). Amounts include: $26,000 each for Messrs. Adcock, Westmoreland and Schwartz.

Bonus amounts for 2001 include a special bonus paid in January 2001 in connection with the grant of non-qualified stock options. Amounts include: $167,000 each for Messrs. Adcock, Schwartz and Westmoreland. The special bonus was made in lieu of annual stock option grants scheduled for 2000 which were postponed until January 2001.

(2) Pursuant to Mr. Hargett's employment agreement dated April 4, 2001, Mr. Hargett was granted 10,000 restricted shares of common stock at $25.58 per share, which vest in on-third increments over a three-year period on each anniversary date of the grant, but vest in full if Mr. Hargett terminates his employment for good reason or if we terminate Mr. Hargett for any reason other than cause, as defined in the employment agreement.

(3) We did not issue any stock appreciation rights or stock options to Named Executive Officers during 2000.

(4) Long-term Incentive Payouts ("LTIP") for 2001 and 2000 were cash payments pursuant to phantom stock rights granted in December 1996, of which 20% were payable on December 16th of each of the years 1997 through 2001. Each phantom stock right represented the right to receive a cash payment determined by the average closing price on the NYSE of one share of common

stock for the five trading days preceding the payout date multiplied by the number of Phantom Stock Rights payable on the payout date.

(5) Includes distributions attributable to overriding royalty interests in our properties paid to Mr. Schwartz of $36,000, $110,000 and $47,000, respectively, for 2002, 2001 and 2000, and paid to Mr. Westmoreland of $14,000, $41,000 and $19,000, respectively, for 2002, 2001 and 2000. Also includes matching contributions we made under our 401(k) and Deferred Compensation Plans.

OPTIONS GRANTED IN 2002

The following table provides certain information with respect to options granted to the Named Executive Officers during 2002 under the 2002 Long-Term Incentive Plan.

	INDIVIDUAL GRANTS(1)				
NAME	NUMBER OF SECURITIES UNDERLYING OPTIONS GRANTED(#)	PERCENT OF TOTAL OPTIONS GRANTED TO EMPLOYEES IN FISCAL YEAR	EXERCISE OR BASE PRICE ($/SH)	EXPIRATION DATE	P APPR
William G. Hargett	95,000	12.6%	$ 30.10	10/16/2012	$
Charles W. Adcock	39,000	5.2%	30.10	10/16/2012	
Steven L. Mueller	39,000	5.2%	30.10	10/16/2012	
Thomas E. Schwartz	20,000	2.7%	30.10	10/16/2012	
James F. Westmoreland	20,000	2.7%	30.10	10/16/2012	

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(1) We have not issued any stock appreciation rights to the Named Executive Officers.

(2) The Securities and Exchange Commission requires disclosure of the potential realizable value or present value of each grant. The disclosure assumes the options will be held for the full ten-year term. The actual value, if any, an executive officer may realize will depend upon the excess of the stock price over the exercise price on the date the option is exercised. There can be no assurance that the stock price will appreciate at the rates shown in the table.

AGGREGATED OPTION EXERCISES IN 2002 AND FISCAL YEAR-END OPTION VALUES

The following table provides information regarding stock options exercised by the Named Executive Officers during the fiscal year ended December 31, 2002, the number of shares of common stock underlying unexercised options held by each Named Executive Officer and the value, based on the closing price of our common stock on the NYSE of $30.60 on December 31, 2002, of exercisable and unexercisable "in the money" stock options held by each of the Named Executive Officers.

NAME	SHARES ACQUIRED ON EXERCISE(#)	VALUE REALIZED($)(1)	NUMBER OF SECURITIES UNDERLYING UNEXERCISED OPTIONS AT FISCAL YEAR-END (#)		VALUE O IN- O FISC
			EXERCISABLE	UNEXERCISABLE	EXERCISAB
William G. Hargett	31,600	$ 206,557	--	--	$
Charles W. Adcock	25,800	370,446	23,848	82,871	124,
Steven L. Mueller	--	--	10,000	79,000	
James F. Westmoreland ...	40,963	556,514	8,648	64,453	
Thomas E. Schwartz	41,400	489,492	14,648	63,871	45,

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(1) The value realized upon the exercise of a stock option is equal to the difference between the market price on the date of exercise and exercise price of the stock option.

COMPENSATION COMMITTEE INTERLOCK AND INSIDER PARTICIPATION

Robert B. Catell, a member of the Compensation Committee, is Chairman of the Board and Chief Executive Officer of KeySpan. Mr. Riordan, a member of the Compensation Committee, was a member of KeySpan's Board of Directors from 1998 until his retirement in May 2002. KeySpan owns approximately 66% of our common stock.

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ITEM 12. SECURITY OWNERSHIP OF BENEFICIAL OWNERS AND MANAGEMENT

The following table presents information as of February 20, 2003 regarding the beneficial ownership of our common stock by common stock equivalents credited to each person who we know to own beneficially more than five percent of the outstanding shares of common stock, each Director, our executive officers, all Directors and executive officers as a group. Unless otherwise indicated, each person shown below has the sole power to vote and the sole power to dispose of the shares of common stock listed as beneficially owned.

NAME OF BENEFICIAL OWNER	COMMON STOCK BENEFICIALLY OWNED		
	COMMON STOCK AND STOCK OPTIONS	COMMON STOCK	OPTIONS TO PURCHASE COMMON STOCK(1)
KeySpan Corporation (3) One MetroTech Center Brooklyn, NY 11201-3850	20,380,392	20,380,392	--

Robert B. Catell	21,000	4,000(4)	17,000
William G. Hargett	17,333	3,333(5)	14,000(5)
David G. Elkins	18,000	5,000	13,000
James Q. Riordan	17,500	500(6)	17,000
Donald C. Vaughn	17,000	--	17,000
Gerald Luterman	11,000	--(7)	11,000
H. Neil Nichols	11,000	--(8)	11,000
Gordon F. Ahalt	6,000	2,000	4,000
Robert J. Fani	7,000	--(9)	7,000(9)
Harold R. Logan, Jr	5,000	--	5,000
Charles W. Adcock	26,324	2,476	23,848(10)
James F. Westmoreland	9,712	1,064	8,648(11)
Thomas E. Schwartz	14,648	--	14,648(12)
Tracy Price	12,700	--	12,700(13)
Steven L. Mueller	10,000	--	10,000(14)
Roger B. Rice	7,000	--	7,000(15)
John H. Karnes	--	--	--(16)
All Directors and executive officers as a group (17 persons)	211,217	18,373	192,844

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* Less than 1%.

(1) The Directors and officers have the right to acquire the shares of common stock reflected in this column currently or within 60 days of the date hereof through the exercise of stock options

(2) The term Phantom Stock Rights refers to units of value which track the performance of common stock. The units do not possess any voting rights or right to dispose of common stock and have been issued to non-employee Directors pursuant to our Deferred Compensation Plan for Non-Employee Directors.

(3) KeySpan holds its shares through its indirect wholly owned subsidiary, THEC Holdings Corp.

(4) Mr. Catell also owns 1,547,385 shares of KeySpan common stock, which includes (i) 1,456,601 outstanding options to purchase shares of KeySpan common stock that are exercisable within 60 days of the date hereof; (ii) 13,801 shares of KeySpan restricted stock; and (iii) 5,146 deferred stock units. In addition, Mr. Catell owns 12.82 shares of KeySpan preferred stock.

(5) Mr. Hargett owns 6,667 shares of restricted common stock of which, 3,333 shares vest within 60 days of the date hereof with the remaining 3,334 shares vesting on the anniversary date of the grant date or April 4, 2004. Mr. Hargett owns 221,400 options, 14,000 of which are exercisable within 60 days of the date hereof.

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(6) Mr. Riordan also owns 24,800 shares of KeySpan common stock, which includes 3,300 options to purchase shares of KeySpan common stock within 60 days

from the date hereof.

(7) Mr. Luterman also owns 169,261 shares of KeySpan common stock including 160,800 options to purchase KeySpan common stock exercisable within 60 days; (ii) 3,042 shares of KeySpan restricted stock; and (iii) 1,389 deferred stock units.

(8) Mr. Nichols also owns 130,505 shares of KeySpan common stock including (i) 128,399 outstanding options to purchase KeySpan common stock exercisable within 60 days hereof and (ii) 1,775 shares of KeySpan restricted stock; and (iii) 1,707 deferred stock units. In addition, Mr. Nichols owns 12.82 shares of KeySpan preferred stock.

(9) Mr. Fani owns 179,222 shares of KeySpan common stock which includes (i) 161,614 options to purchase KeySpan common stock exercisable within 60 days of the date hereof; (ii) 4,438 shares of KeySpan restricted stock; and (iii) 2,768 deferred stock units. In addition, Mr. Fani owns 12.82 shares of KeySpan preferred stock.

(10) Mr. Adcock owns 106,719 options to purchase common stock, 23,848 which are vested.

(11) Mr. Westmoreland owns 73,101 options to purchase common stock, 8,648 which are vested.

(12) Mr. Schwartz owns 78,519 options to purchase common stock, 14,648 options are vested.

(13) Mr. Price owns 83,500 options to purchase common stock, 12,700 options are vested.

(14) Mr. Mueller owns 89,000 options to purchase common stock, 10,000 options are vested.

(15) Mr. Rice owns 55,000 options, 7,000 of which are exercisable within 60 days of the date hereof.

(16) Mr. Karnes owns 60,000 options, none of which have vested.

(17) Based upon 30,961,418 shares outstanding as of February 20, 2003.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

TRANSACTIONS WITH KEYSPAN

We began exploring for natural gas and oil in December 1985 on behalf of The Brooklyn Union Gas Company. Brooklyn Union is an indirect wholly owned subsidiary of our majority stockholder, KeySpan. On September 20, 1996, we completed an initial public offering and issued 7,130,000 shares, or 31%, of our common stock to the public. As of February 20, 2003, THEC Holdings Corp., an indirect wholly owned subsidiary of KeySpan, owned approximately 66% of the outstanding shares of our common stock.

All transactions between us and KeySpan were at terms at least as favorable to us as could have been obtained from unaffiliated third parties, as determined by our board of directors or a committee of independent directors appointed by our board. Pursuant to the terms of the indenture governing our 8?% senior subordinated notes, we are prohibited from entering into any related party transaction unless such transaction is on terms that are no less favorable to us than those that would have been obtained in a comparable transaction by us with an unrelated third party. Any related party transactions in excess of $2.5 million must be approved by a majority of the disinterested members of the board of directors, and any related party transaction in excess of $10 million requires a fairness opinion from an investment banking firm of national standing.

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 of $7.7 million in 2000 and $20.7 million during 1999. 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. In addition, we received reimbursements from KeySpan for a portion of our general and administrative costs.

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. In addition, effective with the termination of the exploratory term of the joint venture, we have not received any further reimbursement from KeySpan for general and administrative costs.

From the inception of the joint venture in January 1999 through December 31, 2002, we drilled a total of 28 wells: 21 exploratory wells of which 17 were successful and seven development wells of which six were successful. KeySpan spent a total of $118.3 million, with $19.0 million, $17.2 million and $46.5 million, respectively being spent during 2002, 2001 and 2000. Subsequent to the termination of the primary exploratory term of the joint venture, KeySpan's participation in additional wells was to further develop or delineate reservoirs previously discovered.

Acquisition of KeySpan Joint Venture Assets

On October 11, 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. 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. The interests purchased were in the following blocks: Vermilion 408, East Cameron 81 and 84, High Island 115, Galveston Island 190 and 389, Matagorda Island 704 and North Padre Island 883. KeySpan has retained its 45% interest in four blocks: South Timbalier 314 and 317 and Mustang Island 725 and 726 as these blocks are in various stages of development. KeySpan has committed to continued participation in the ongoing development of these blocks which includes the completion of the platform and production facilities at South Timbalier 314/317 together with possible further developmental drilling at both South Timbalier 314/317 and Mustang Island 725/726. As of 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 purchase 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.

Our Board of Directors appointed a special committee, comprised entirely of independent directors to review the proposed transaction with KeySpan. In addition, the special committee discussed the history and terms of the transaction with our senior management. After completing its review, the special committee unanimously concluded that the transaction was advisable and in our best interests and that the terms of the transaction were at least as favorable to us as terms that would have been obtainable at the time in a comparable transaction with an unaffiliated party. In reaching its decision, the special committee considered numerous factors in consultation with its financial and legal advisors.

KeySpan Credit Facility and Conversion

On March 31, 2000, we converted $80 million of borrowings that were outstanding under a revolving credit facility with KeySpan into 5,085,177 shares of our common stock at a conversion price of $15.732 per share. The revolving credit facility was entered into in November 1998 to fund the acquisition of our Mustang Island A31/32 Field. Upon conversion on March 31, 2000, KeySpan's ownership interest in our company increased from 64% to 70%. At December 31, 2002 KeySpan's ownership in our company was 66% with the decrease attributable to an increase in our common shares outstanding due to the exercise of stock options subsequent to the conversion transaction. The conversion price was determined based upon the average of the closing prices of our common stock, rounded to three decimal places, as reported under "NYSE Composite Transaction Reports" in the Wall Street Journal during the 20 consecutive trading days ending three trading days prior to March 31, 2000. The conversion of the revolving credit facility and the corresponding issuance of additional shares of our common stock to KeySpan was approved by our stockholders at our annual meeting held April 27, 1999. Borrowings under the facility bore interest at LIBOR plus 1.4% and we incurred a quarterly commitment fee of 0.125% on the unused portion of the maximum commitment. The credit facility terminated on March 31, 2000. For the year ended December 31, 2000, we incurred $1.5 million in interest and fees to KeySpan.

Review of Strategic Alternatives

In September 1999, we, along with KeySpan, our majority stockholder, announced our intention to review strategic alternatives for Houston Exploration and for KeySpan's investment in Houston Exploration. KeySpan was assessing the role of our company within its future strategic plan, and was considering a full range of strategic transactions including the sale of all or a portion of Houston Exploration. J.P. Morgan Securities Inc. was retained by KeySpan as financial advisor to assist in the strategic review on behalf of KeySpan. Our Board of Directors appointed a special committee comprised of outside directors to assist in the review process. On February 25, 2000, together with KeySpan we jointly announced that the review of strategic alternatives had been completed and that KeySpan plans to retain its equity interest in us for the foreseeable future, however, KeySpan considers its investment in Houston Exploration a non-core asset. We incurred expenses relating to this review of strategic alternatives totaling $0.1 million during 2001 and $1.8 million during 2000.

Sale of Section 29 Tax Credits

In January 1997, we entered into an agreement to sell to a subsidiary of KeySpan interests in our onshore producing wells that produce from formations that qualify for tax credits 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. KeySpan acquired an economic interest in wells that are 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.

We manage and administer the daily operations of the properties in exchange for an annual management fee of $100,000. The income statement effect, representing benefits received from Section 29 tax credits, was a benefit of $0.8 million, $0.8 million, and $0.9 million, respectively, for each of the years ended December 31, 2002, 2001, and 2000. The tax credits expired December 31, 2002 and under the terms of the agreement, we are required to repurchase the interests in the producing wells for KeySpan. We are planning to complete the repurchase transaction in 2003 and the repurchase price is estimated at approximately $2.0 million.

Registration Rights Agreement.

Under a registration rights agreement entered into as of July 2, 1996 between us and THEC Holdings Corp., we have agreed to file, upon the request of KeySpan, a registration statement under the Securities Act for the purpose of enabling KeySpan to offer and sell any securities we issued to THEC Holdings. KeySpan may exercise these rights at any time. We will bear the costs of any registered offering, except that KeySpan will pay any underwriting commissions relating to any offering, any transfer taxes and any costs of complying with foreign securities laws at KeySpan's request, and each party will pay for its counsel and accountants. We have the right to require KeySpan to delay any exercise by KeySpan of its rights to require registration and other actions for a period of up to 180 days if, in our judgment, we or any offering we are then conducting or about to conduct would be adversely affected. We have also granted KeySpan the right to include its securities in registration statements covering offerings by us, and we will pay all costs of offerings other than underwriting commissions and transfer taxes attributable to the securities sold on behalf of KeySpan. We have agreed to indemnify KeySpan, its officers, directors, agents, any underwriter, and each person controlling any of the foregoing, against liabilities under the Securities Act or the securities laws of any state or country in which our securities are sold pursuant to the registration rights agreement.

EMPLOYMENT AGREEMENTS

We entered into an employment agreement with Mr. Hargett as President and Chief Executive Officer effective April 4, 2001. Mr. Hargett's employment agreement was amended on May 17, 2002 to clarify that Mr. Hargett would be paid reasonable compensation in an amount between $3,000,000 and $7,500,000 as determined under the agreement in the event of the sale of all or substantially all of our assets or the acquisition by any person other than KeySpan of a majority of our outstanding common stock. Currently, Mr. Hargett is entitled to an annual base salary of $450,000 and an annual incentive bonus of 70% of base salary if we meet financial targets established by our Board of Directors. On the effective date of the agreement, we granted Mr. Hargett 10,000 restricted shares of common stock, with fair value of $255,800, which vest in one-third increments over a three-year period on each anniversary date of the grant. This restricted stock grant vests in full if Mr. Hargett terminates his employment for good reason or if we terminate Mr. Hargett for any reason other than cause, as defined in the employment agreement. For the year ended December 31, 2002, Mr. Hargett was eligible to receive 70% of his base salary as bonus under our Employee Annual Incentive Compensation Plan if certain pre-established objectives were achieved for the year. Mr. Hargett achieved 97% of his targeted objectives. Mr. Hargett's year-end base salary rate of $450,000 was used in calculating his bonus award for 2002, and accordingly, he earned a cash bonus of $306,000.

Effective November 18, 2002, we entered into an employment agreement with John H. Karnes as Senior Vice President and Chief Financial Officer. Under the agreement, we agreed to pay Mr. Karnes an annual salary of $275,000 and an annual incentive bonus of 55% of his base salary if we meet the targets set by our Board of Directors.

We have entered into employment agreements with Messer. Adcock, Mueller, Westmoreland, Rice, Schwartz and Price. Under the terms of these agreements, these individuals receive base salaries of $245,000, $245,000, $230,000, 205,000, 205,000 and 195,000 respectively. Each individual is also entitled to annual incentive bonuses of 55% of base salary if we meet financial targets established by our Board of Directors.

The initial term of all our employment agreements automatically extends to the third anniversary of the respective effective date. The term of each agreement is automatically extended one year on each anniversary unless either party gives notice at least 90 days prior to the anniversary of its intention not to extend the term of the agreement. We may terminate all of our employment agreements for cause or upon the death or disability of the employee. The employee may terminate the employment agreements for any reason. 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 which includes salary, car allowance and annual bonus, which would be calculated as though our financial targets had been met, and the continuation of welfare benefits. The employment agreements further provide that a change of control will terminate the employment agreements, triggering the lump-sum severance payment obligation in the amount of 2.99 times the employee's total compensation, and termination of the employment agreements will also terminate the non-compete provisions the agreements contain. The agreements further provide that if any payments made to the executives, whether or not under the agreement, would result in an excise tax being imposed on the executives under Section 4999 of the Internal Revenue Code, we will make each of the executives "whole" on a net after-tax basis.

Under their employment agreements, each of our executive officers would be entitled to a lump sum severance payment equal to 2.99 times their current total annual compensation, if we terminated their employment agreements without cause or if the employee terminates his employment agreement for good reason. Mr. Hargett would receive approximately $2.3 million, Mr. Karnes would receive approximately $1.3 million, Messrs. Adcock and Mueller would

each receive approximately $1.2 million. Mr. Westmoreland would receive approximately $1.1 million, Messrs. Schwartz and Rice would each receive approximately $1.0 million and Mr. Price would receive approximately $0.9 million.

Effective as of October 26, 1999, our Board of Directors established the Change of Control Plan under which all employees, including the executive officers, in the event of a "change of control" will be entitled to receive a "stay-on" bonus in the amount of 125% of the employee's regular target bonus percentage, and, in addition to other severance benefits, all stock options, phantom stock and 401(k) contributions will fully vest. See "Change of Control Plan."

SUPPLEMENTAL EXECUTIVE PENSION PLAN

Effective immediately prior to our initial public offering in 1996, we adopted an unfunded, non-qualified Supplemental Executive Pension Plan under which our former President and Chief Executive Officer, Mr. Floyd, is the only beneficiary. Under this plan, we have agreed to pay Mr. Floyd $100,000 per year for life. Should he predecease his spouse, Mr. Floyd's surviving spouse will be paid $50,000 per year for her life. Mr. Floyd retired March 31, 2001 and during 2002 we paid Mr. Floyd a total of $100,000.

401(k) PLAN

We maintain a 401(k) Plan for our employees. Under the 401(k) Plan, eligible employees may elect to have us contribute on their behalf up to 12.5% of their base compensation on a before tax basis in accordance with the limitations imposed under the Internal Revenue Code. We make a matching contribution of $1.00 for each $1.00 of employee deferral, in accordance with the 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 among various investment funds in accordance with the directions of each participant. An employee's salary deferral contributions under the 401(k) Plan are 100% vested. Our matching contributions vest at the rate of 20% per year of service. Participants are entitled to payment of their vested account balances upon termination of employment.

1996 STOCK OPTION PLAN

We adopted the 1996 Stock Option Plan in September 1996 in conjunction with our initial public offering. The 1996 Stock Option Plan allows us to grant options not to exceed 10% of the shares of our common stock outstanding from time to time. The 1996 Stock Option Plan is administered by the Compensation Committee of the Board of Directors which, at its discretion, may grant either incentive stock options or non-qualified stock options to eligible individuals. All employees, including consultants and advisors of our company and our affiliates are eligible to participate in the 1996 Stock Option Plan. Prior to our adoption of the 1999 Stock Option Plan in October 1999, non-employee Directors were also eligible to participate in the 1996 Stock Option Plan. All option grants made to non-employee Directors after October 1999 are made under terms of the 1999 Stock Option Plan or the 2002 Long-term Incentive Plan. Options granted under the 1996 Stock Option Plan 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 non-employee Directors which are fully vested on the date of grant. During 2002, options to purchase 14,509 shares of our common stock were granted under the 1996 Stock Option Plan. At December 31, 2002, a total of 329 shares remained available for grant under the 1996 Plan. We may adjust any options issued under the 1996 Stock Option Plan in the event of stock splits and other corporate events. In addition, we may appropriately adjust the exercise price for options in the event that the outstanding shares of common stock are changed into or exchanged for a different number or kind of shares or other securities by reason of merger, stock dividend, combination of shares or the like.

1999 NON-QUALIFIED STOCK OPTION PLAN

On October 26, 1999, our Board of Directors adopted the 1999 Non-Qualified Stock Option Plan for employees (excluding executive officers), non-employee Directors, consultants and advisors of our company and our affiliates. With respect to non-employee Directors only, the 1999 Non-Qualified Stock Option Plan amends and succeeds the 1996 Plan (under which no more options may be granted to non-employee Directors). The 1999 Non-Qualified Stock Option Plan is administered by the Compensation Committee, which at its discretion, may grant awards to eligible individuals with the exception of non-employee Directors who receive automatic grants under the 1999 Non-Qualified Stock Option Plan. The options granted under the 1999 Non-Qualified Stock Option Plan are all non-qualified, expire 10 years from date of grant and vest immediately for non-employee Directors and in one-fifth increments on each of the first five anniversaries of the grant for other eligible individuals. During 2002, we granted a total of 145,600 options under the 1999 Non-Qualified Stock Option Plan, of which 18,000 options were granted to non-employee directors pursuant to our compensation plan for non-employee directors. At December 31, 2002, a total of 566 shares remained available for grant under the 1999 Plan.

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We may adjust options issued under the 1999 Non-Qualified Stock Option Plan in the event of stock splits and other corporate events. In addition, we may appropriately adjust the exercise price for options in the event that the outstanding shares of common stock are changed into or exchanged for a different number or kind of shares or other securities by reason of merger, stock dividend, combination of shares or the like.

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2002 LONG-TERM INCENTIVE PLAN

In January 18, 2002, our Board of Directors adopted the 2002 Long-Term Incentive Plan for our non-employee Directors and employees, consultants and advisors of our company and our affiliates. The 2002 Long-Term Incentive Plan is administered by the Compensation Committee, which at its discretion, may grant awards of options or restricted stock to eligible individuals with the exception of non-employee Directors who receive automatic grants under the 2002 Long-Term Incentive Plan. Awards granted to non-employee Directors, consultants and advisors under the 2002 Long-Term Incentive Plan are all non-qualified options, while employees may receive incentive or non-qualified options and/or restricted stock. Options may not be exercised after 10 years from the date they were granted. In the case of a 10% stockholder, incentive options may not be exercised after five years from the date the option is granted. Options vest immediately for non-employee Directors and at the times provided in their option agreement for other eligible individuals but in no event sooner than six months from the date granted. Terms and conditions of the restricted stock awards, including the duration of the restricted period during which, and the conditions, including performance objectives, if any, under which if not achieved, the restricted stock may be forfeited, are determined by the Compensation Committee. Unless conditioned upon the achievement of performance objectives or a special determination is made by the Compensation Committee as to a shorter restricted period, the restricted period will not be less than five years. During 2002, we granted a total of 593,950 options under the 2002 Long-Term Incentive Plan, of which 5,000 options were granted to non-employee directors. No shares of restricted stock were granted under the plan. At December 31, 2002, a total of 906,050 shares remained available for grant under the 2002 Plan. We may adjust options issued under the 2002 Long-Term Incentive Plan in the event of stock splits and other corporate events. In addition, we may appropriately adjust the exercise price for options in the event that the outstanding shares of common stock are changed into or exchanged for a different number or kind of shares or other securities by reason of merger, stock dividend, combination of shares or the like.

DEFERRED COMPENSATION PLAN

In November 2002, our Board of Directors adopted a deferred compensation plan for the benefit of our employees. The plan 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 ($11,000 per year or $12,000 per year for employees over 50 years of age for 2002) 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 2002, we made matching contributions totaling $0.5 million to the deferred compensation plan. Employer contributions vest 20% per year and become fully vested after a 5 year period. All contributions to the plan are held in trust and invested, at the direction of the employee, in various investment funds, including company stock. Participants are entitled to distribution of their deferrals and the vested portion of our matching contributions at predetermined future dates or upon termination of their employment.

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.

CHANGE OF CONTROL PLAN

Effective as of October 26, 1999, our Board of Directors established the Change of Control Plan pursuant to which, upon a change of control all employees, including executive officers, will be entitled to receive "stay-on" bonuses in the amount of 125% of the employee's regular target bonus percentage. In addition, a change of control will cause all stock options, phantom stock and other employee benefits to become fully vested.

Further, if we or our successor terminates employees, other than executive officers, within one year of the change of control other than for cause, as defined in the Change of Control Plan, or our employees suffer a significant adverse change in employment, a reduction in salary or relocation of more than 30 miles, these employees will be entitled to severance benefits in the form of a lump sum payment calculated pursuant to a formula based upon each employee's base salary and years of service. The calculation of lump sum payments for executive officers is stated in their respective employment agreements.

A "change of control" is deemed to occur if either:

o a person, entity or group other than us or our affiliate acquires 20% or more of the combined voting power of our then outstanding voting securities,

o a reorganization, merger, consolidation or liquidation is approved; or

o the individuals constituting our Board of Directors on October 26, 1999 cease to constitute a majority of our Board of Directors unless the election of each new director was approved by a vote of at least a majority of the directors then still in office who were directors at the beginning of the period.

ITEM 14. 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, with the participation of 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 our disclosure controls and procedures are effective. 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 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-34 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 March 25, 2002 to provide new information regarding hedges for the years ended December 31, 2002 and 2003 in Item 5. - Other Events

Current Report on Form 8-K filed April 5, 2002 to provide information regarding change of certifying accountant in Item 4. - Changes in Registrant's Certifying Accountant

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this amendment no.1 of this report to be signed on its behalf by the undersigned, thereunto duly authorized.

THE HOUSTON EXPLORATION COMPANY

By: /s/ James F. Westmoreland

James F. Westmoreland
Vice President and Chief Accounting Officer

Date: November 12, 2003

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.

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.

GLOSSARY OF OIL AND GAS TERMS

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 oil or gas 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.

INDEX TO FINANCIAL STATEMENTS

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 66% owned subsidiary of KeySpan Corporation) and subsidiary (the "Company") as of December 31, 2002 and 2001, and the related consolidated statements of operations, stockholders' equity and comprehensive income(loss) and cash flows for years then ended. 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. The consolidated financial statements of the Company for the year ended December 31, 2000 were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion on those financial statements in their report dated February 4, 2002, which included an emphasis of matter paragraph relating to the adoption of a new accounting standard. Those auditors reported on such financial statements prior to the restatement discussed in Note 11.

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, the 2002 and 2001 consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2002 and 2001, and the results of its operations and its cash flows for the years then ended 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. 133, "Accounting for Derivatives Instruments and Hedging Activities," as amended, on

January 1, 2001.

As discussed in Note 11 to the consolidated financial statements, the 2001 financial statements have been restated for the effects of transportation expenses under Emerging Issues Task Force ("EITF") Issue No. 00-10 and certain disclosures relating to the adoption of SFAS No. 133.

As discussed above, the consolidated financial statements of the Company for the year ended December 31, 2000 were audited by other auditors who have ceased operations. As described in Note 11, those consolidated financial statements have been reclassified to effect EITF Issue No. 00-10, "Accounting for Shipping and Handling Fees and Costs". We audited the adjustments described in Note 11 that were applied to conform the 2000 consolidated financial statements to comparative presentation required by EITF Issue No. 00-10. Our audit procedures with respect to the 2000 disclosures in Note 11 included (i) comparing the amounts shown as transportation costs to the Company's underlying accounting analysis obtained from management, and (ii) on a test basis, comparing the amounts comprising the transportation costs obtained from management to independent supporting documentation, and (iii) testing the mathematical accuracy of the underlying analysis. In our opinion, such reclassifications have been properly applied. However, we were not engaged to audit, review or apply any procedures to the 2000 consolidated financial statements of the Company other than with respect to such reclassifications and, accordingly, we do not express an opinion or any form of assurance on the 2000 financial statements taken as a whole.

DELOITTE & TOUCHE LLP

Houston, Texas
February 7, 2003 (February 20, 2003 as to the first paragraph of "Legal Proceedings" in Note 9; November 13, 2003, as to the sixth paragraph of "Natural Gas and Oil Properties," and the first paragraph of "New Accounting Pronouncements" in Note 1, and the third paragraph of "2002" in Note 7.)

The following report is a copy of a report previously issued by Arthur Andersen LLP, which has ceased operations, and has not been reissued by Arthur Andersen LLP. Arthur Andersen LLP reported on such financial statements prior to the restatements discussed in Note 11 for the application of Emerging Issues Task Force Issue No. 00-10, "Accounting for Shipping and Handling Fees and Costs" and certain disclosures relating to the adoption of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

We have audited the accompanying consolidated balance sheets of The Houston Exploration Company (a Delaware corporation and an indirect 67%-owned subsidiary of KeySpan Corporation) and subsidiary, as of December 31, 2001 and 2000, and the related consolidated statements of operations, stockholders' equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence 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, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of The Houston Exploration Company and subsidiary, as of December 31, 2001 and 2000, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As discussed in the Note 1 to the Consolidated Financial Statements, the Company adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities, as amended", on January 1, 2001.

ARTHUR ANDERSEN LLP

New York, New York
February 4, 2002

THE HOUSTON EXPLORATION COMPANY
CONSOLIDATED BALANCE SHEETS

	--
	--
	(IN
ASSETS:	
Cash and cash equivalents	$
Accounts receivable	
Accounts receivable -- Affiliate	
Derivative financial instruments	
Inventories	
Prepayments and other	
	--
Total current assets	
Natural gas and oil properties, full cost method	
Unevaluated properties	
Properties subject to amortization	
Other property and equipment	
	--
Less: Accumulated depreciation, depletion and amortization	

Other assets	
TOTAL ASSETS	$
LIABILITIES:	
Accounts payable and accrued expenses	$
Derivative financial instruments	
Total current liabilities	
Long-term debt and notes	
Deferred federal income taxes	
Derivative financial instruments	
Other deferred liabilities	
TOTAL LIABILITIES	
COMMITMENTS AND CONTINGENCIES (SEE NOTE 9)	
STOCKHOLDERS' EQUITY:	
Common Stock, $.01 par value, 50,000,000 shares authorized and 30,954,018 shares issued and outstanding at December 31, 2002 and 30,463,230 shares issued and outstanding at December 31, 2001	
Additional paid-in capital	
Unearned compensation	
Retained earnings	
Accumulated other comprehensive income (loss)	
TOTAL STOCKHOLDERS' EQUITY	
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$

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

THE HOUSTON EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS

	YEARS ENDED DECEMBER 3	
	2002	2001
	(IN THOUSANDS, EXCEPT PER SH	As Restated
REVENUES:		
Natural gas and oil revenues	$ 344,295	$ 387,156
Other	1,086	1,353
Total revenues	345,381	388,509

OPERATING EXPENSES:		
Lease operating expense	33,976	25,291
Severance tax	9,487	11,035
Transportation expense	9,317	7,652
Depreciation, depletion and amortization	171,610	128,736
Writedown in carrying value of natural gas and oil properties	--	6,170
General and administrative, net	13,077	17,110
Total operating expenses	237,467	195,994
Income from operations	107,914	192,515
Other (income) expense	(9,070)	119
Interest expense, net	7,398	2,992
Income before income taxes	109,586	189,404
Provision for federal income taxes	39,092	66,803
NET INCOME	$ 70,494	$ 122,601
Net income per share - basic	$ 2.31	$ 4.06
Net income per share - fully diluted	$ 2.28	4.00
Weighted average shares outstanding - basic	30,569	30,228
Weighted average shares outstanding - fully diluted	30,878	30,645

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

THE HOUSTON EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
AND COMPREHENSIVE INCOME
(IN THOUSANDS, EXCEPT SHARE DATA)

	COMMON STOCK		ADDITIONAL PAID-IN	UNEAR
	SHARES	$ VALUE	CAPITAL	COMPENS
BALANCE JANUARY 1, 2000	23,923,020	$ 239	$ 231,370	$
Issuance of common stock, par value $0.01(1)(2)	5,906,030	59	93,835	
Comprehensive Income:				
Net income				
Total comprehensive income				
BALANCE DECEMBER 31, 2000	29,829,050	$ 298	$ 325,205	$
Issuance of common stock, par value $0.01(1)	624,180	6	10,183	
Issuance of restricted common stock,				

par value $0.01(3)	10,000	1	255	
Amortization of restricted stock				
Tax benefit from exercise of non-qualified Stock options			1,334	
Comprehensive income:				
Net income				
Other comprehensive income (as restated)(4):				
Cumulative effect of accounting change for derivative instruments, net of tax benefit of $26,274				
Derivative settlements reclassified to income, net of tax benefit of $4,524				
Unrealized gain due to change in fair value of derivative instruments, net of tax expense of $49,618				
Total comprehensive income				
BALANCE DECEMBER 31, 2001	30,463,230	$ 305	$ 336,977	$
Issuance of common stock, value $0.01(1)	490,788	5	9,663	
Contributed capital from KeySpan (5)			2,039	
Amortization of restricted stock				
Tax benefit from exercise of non-qualified stock options			4,775	
Comprehensive income:				
Net income				
Other comprehensive income:				
Derivative settlements reclassified to income, net of tax benefit of $5,725				
Unrealized loss due to change in fair value of derivative instruments, net of tax benefit of $26,665				
Total comprehensive income				
BALANCE DECEMBER 31, 2002	30,954,018	$ 310	$ 353,454	$

	TOTAL STOCKHOLDERS' EQUITY
BALANCE JANUARY 1, 2000	$ 217,590
Issuance of common stock, par value $0.01(1)(2)	93,894
Comprehensive Income:	
Net income	85,258
Total comprehensive income	85,258
BALANCE DECEMBER 31, 2000	$ 396,742
Issuance of common stock, par value $0.01(1)	10,189
Issuance of restricted common stock, par value $0.01(3)	
Amortization of restricted stock	64
Tax benefit from exercise of non-qualified Stock options	1,334
Comprehensive income:	
Net income	122,601
Other comprehensive income (as restated)(4):	

Cumulative effect of accounting change for derivative instruments, net of tax benefit of $26,274	(48,795)
Derivative settlements reclassified to income, net of tax benefit of $4,524	(8,402)
Unrealized gain due to change in fair value of derivative instruments, net of tax expense of $49,618	92,148
Total comprehensive income	157,552
BALANCE DECEMBER 31, 2001	$ 565,881
Issuance of common stock, value $0.01(1)	9,668
Contributed capital from KeySpan (5)	2,039
Amortization of restricted stock	85
Tax benefit from exercise of non-qualified stock options	4,775
Comprehensive income:	
Net income	70,494
Other comprehensive income:	
Derivative settlements reclassified to income, net of tax benefit of $5,725	(10,633)
Unrealized loss due to change in fair value of derivative instruments, net of tax benefit of $26,665	(49,520)
Total comprehensive income	10,341
BALANCE DECEMBER 31, 2002	$ 592,789

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

(2) Includes 5,085,177 shares issued on March 31, 2000 to our majority stockholder, KeySpan Corporation, pursuant to the conversion of $80 million in outstanding borrowings under a revolving credit facility with KeySpan. See Note 3 - Stockholders' Equity - KeySpan Credit Facility and Conversion.

(3) 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.

(4) Comprehensive income for the year ended December 31, 2001 has been restated to present the individual components for 2001 in accordance with the disclosure requirements of Statement of Financial Accounting Standards No. 133 "Accounting for Derivatives Instruments and Hedging Activities," as amended. See Note 11 - Restatements and Reclassifications - Adoption of SFAS No. 133.

(5) 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.

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

	YEARS END	
	2002	
		(IN
OPERATING ACTIVITIES:		
Net income	$ 70,494	$
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	171,610	
Writedown in carrying value of natural gas and oil properties	--	
Deferred income tax expense	39,860	
Stock compensation expense	85	
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	(39,937)	
(Increase) decrease in inventories	(283)	
Increase in prepayments and other	(4,637)	
Decrease (increase) in other assets	4,427	
Increase in deferred liabilities	741	
Increase (decrease) in accounts payable and accrued expenses	1,509	
Net cash provided by operating activities	243,869	
INVESTING ACTIVITIES:		
Investment in property and equipment	(257,436)	
Dispositions and other	5,311	
Net cash used in investing activities	(252,125)	
FINANCING ACTIVITIES:		
Proceeds from long-term borrowings	79,000	
Repayments of long-term borrowings	(71,000)	
Proceeds from issuance of common stock	9,668	
Net cash provided by (used in) financing activities	17,668	
Increase (decrease) in cash and cash equivalents	9,412	
Cash and cash equivalents, beginning of year	8,619	

Cash and cash equivalents, end of year	$ 18,031	$
SUPPLEMENTAL INFORMATION:		
Cash paid for interest	$ 14,906	$
Cash (refund) payment of federal income taxes	$ (400)	$

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

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 -- SUMMARY OF ORGANIZATION AND SIGNIFICANT ACCOUNTING POLICIES

Organization

We are an independent natural gas and oil company engaged in the exploration, development, exploitation and acquisition of domestic natural gas and oil properties. Our operations are focused in South Texas, in the Gulf of Mexico and in the Arkoma Basin of Oklahoma and Arkansas.

At December 31, 2002, our net proved reserves were 650 billion cubic feet equivalent or Bcfe, with a present value, discounted at 10% per annum, of cash flows before income taxes of $1.3 billion. Our reserves are fully engineered on an annual basis by independent petroleum engineers. Our focus is natural gas. Approximately 94% of our net proved reserves at December 31, 2002 were natural gas, approximately 69% of which were classified as proved developed. We operate approximately 85% of our properties.

We began exploring for natural gas and oil in December 1985 on behalf of The Brooklyn Union Gas Company. Brooklyn Union is an indirect wholly owned subsidiary 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, 2002, THEC Holdings Corp., an indirect wholly owned subsidiary of KeySpan, owned approximately 66% 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. 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 from the estimates.

Business Segment Information

SFAS No. 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 paragraph 17 of SFAS No. 131. All of our operations involve the exploration, development and production of natural gas and oil and all of our operations are located in the United States. We have a single, company-wide management team that administers all properties as a whole rather than as discrete operating segments. We track only basic operational data by area. We do not maintain separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis. Throughout the year, we freely allocate capital resources on a project-by-project basis across our entire asset base to maximize profitability without regard to individual areas or segments.

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, as adjusted, by the sum of the weighted average number of shares of common stock outstanding plus all potentially dilutive securities.

Under the requirements of the Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards ("SFAS") No. 128, our earnings per share are as follows:

YEA

	2002
	(IN THOUSA
Net income	$ 70,494
Weighted average shares outstanding	30,569
Add dilutive securities:	
Options	309
Total weighted average shares outstanding and dilutive securities	30,878
Net income per share - basic	$ 2.31
Net income per share - fully diluted	$ 2.28

For the years ended December 31, 2002, 2001 and 2000, the calculation of shares outstanding for fully diluted EPS does not include the effect of outstanding stock options to purchase 1,880,029, 1,182,843 and 973,616 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 EPS.

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. Unevaluated properties and related costs are excluded from our amortization base until we have made a determination as to the existence of proved reserves. We review our unevaluated properties at the end of each quarter to determine if the costs incurred should be reclassified to the full cost pool and thereby subject to amortization. Our amortization base includes estimates for future development costs as well as future abandonment and dismantlement costs. 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 of the present value of future net revenues, discounted at 10%, 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 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, held flat over the life of the reserves. We use derivative financial instruments that qualify for hedge accounting under SFAS No. 133 to hedge against the volatility of natural gas prices, and in accordance with current Securities and Exchange Commission guidelines, we include estimated future cash

flows from our hedging program in our ceiling test calculation. 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). 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.

In calculating our ceiling test at December 31, 2002 and 2000, we estimated, using a wellhead price of $4.35 per Mcf and $9.55 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 $279.4 million (after tax) for 2002 and $1.4 billion (after tax) for 2000. No writedown is required when a cushion exists.

Proceeds from the dispositions of natural gas and oil properties are recorded as reductions of capitalized costs, with no gain or loss recognized, unless the adjustments significantly alter the relationship of unamortized capitalized costs and total 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 in-progress and wells pending determination. 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 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 $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. At December 31, 2001, of the $178.0 million of unevaluated property costs, $72.5 million, $20.3 million and $17.0 million were incurred in 2001, 2000 and 1999, respectively, and $68.2 million was incurred prior to 1998. We estimate these costs will be evaluated within a four-year period.

Cash and Cash Equivalents

We consider all highly liquid short-term investments with original maturities of 90 days or less to be cash equivalents.

Other Property and Equipment

Other property and equipment includes the costs of West Virginia gathering facilities which 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.

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. These differences relate primarily to

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

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

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, certain costs are capitalized that are directly identified with 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 2002, 2001 and 2000, of $13.2 million, $12.8 million and $9.6 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 $1.8 million, $1.2 million, and $3.6 million for the years ended December 31, 2002, 2001 and 2000, respectively, were allocated as reductions to general and administrative expenses incurred. Included in reimbursements received during 2000 are general and administrative reimbursements received from KeySpan pursuant to the joint exploration agreement with KeySpan, (see Note 6 - Related Party Transactions - KeySpan Joint Venture) of $2.5 million 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 some properties under development which are not currently being amortized. For the years ended December 31, 2002, 2001 and 2000, we capitalized interest costs of $8.0 million, $12.0 million, $13.7 million, respectively.

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 marketed-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 $33,000 at December 31, 2002 and a net liability of $376,000 at December 31, 2001, 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 No. 133 on January 1, 2001, our derivative financial instruments are reported on the balance sheet at fair market value.

Hedging Contracts

We utilize derivative commodity instruments to hedge future sales prices on a portion of our natural gas production in order to achieve a more predictable cash flow and to reduce our exposure to adverse price fluctuations. 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 from possible favorable price movements. Hedging instruments that we use include swaps, costless collars and options, which we generally place with major financial institutions that we believe are minimal credit risks. Our hedging strategies meet the criteria for hedge accounting treatment under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities". Accordingly, we mark-to-market our derivative instruments at the end of each quarter, and defer the effective portion of the gain or loss on the change in fair value of our derivatives in accumulated other comprehensive income, a component of stockholders' equity. We recognize gains and losses when the underlying transaction is completed, at which time these gains and losses are reclassified from accumulated other comprehensive income and included in earnings as a component of natural gas revenues in accordance with the underlying hedged transaction. If hedging instruments cease to meet the criteria for deferred recognition, any gains or losses would be currently recognized in earnings. See Note 7 -- Hedging Contracts summary of our derivative contracts and the fair market value of those contracts as of December 31, 2002 and 2001.

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, however, recent market conditions resulting in downgrades to credit ratings of energy merchants have affected the liquidity of several of our purchasers. During the third quarter of 2002, we discontinued selling our natural gas and oil to several energy merchants that received downgrades to their credit ratings. We are continuing to sell gas to companies that have posted letters of credit to secure their performance under the purchase contracts. We have not experienced credit loss from any of these purchasers. Based on the current demand for natural gas and oil, we do not expect that termination of sales to previous purchasers would have a material adverse effect on our ability to sell our production at favorable market prices.

Further, our natural gas futures and swap contracts also expose us to credit risk in the event of nonperformance by counterparties. Generally, these contracts are with major investment grade financial institutions and historically we have not experienced material credit losses. 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.

Stock Options

Historically, we have accounted for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Accordingly, compensation cost for stock options is 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. See Note 4 -- Employee Benefit and Stock Plans -- Fair Value of Employee Stock-Based Compensation for disclosure had stock options been accounted for based upon the fair value provisions of the SFAS No. 123, as amended, "Accounting for Stock-Based Compensation." On January 1, 2003, we adopted the fair value expense recognition provisions of SFAS No. 123 as amended by SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure." SFAS No. 148 proposes three alternatives transition methods for adopting the fair value method under SFAS No. 123:

- Prospective Method - recognize fair value expense for all awards granted in the year of adoption but not previous awards;

- o Modified Prospective Method - recognize fair value expense for the unvested portion of all stock options granted, modified, or settled since 1994 (i.e., the unvested portion of the prior awards or those granted in the year of adoption must be recorded using the fair value method); and

- o Retroactive Restatement Method - similar to the Modified Prospective Method except that all prior periods are restated.

We adopted SFAS No. 123 using the Prospective Method and as a result will record as compensation expense the fair value of all stock options issued subsequent to January 1, 2003. We do not expect the adoption of the provisions of SFAS No. 123 to have a material impact on our financial position, results of operations or cash flows.

New Accounting Pronouncements

SFAS No. 141, "Business Combinations" and SFAS No. 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 clarify that more assets should be distinguished and classified between tangible and intangible. We understand that the issue is under evaluation as to whether provisions of SFAS No. 141 and SFAS No. 142 may call for mineral rights held under lease or other contractual arrangements to be classified in the balance sheet as intangible assets together with cash costs of oil and gas leasehold interests acquired. The issue is under review, because it is believed that no oil and gas exploration and production company was known to have changed their tangible asset balance sheet classification of mineral rights or leasehold costs upon adopting of SFAS Nos. 141 and 142, including us. If these types of leasehold costs (both proved and unevaluated) are determined to be intangible assets, they would be classified separately from oil and natural gas properties as intangible assets on our balance sheets. This issue relates only to balance sheet classification and presentation and will not have an effect on cash flows or results of operations. For the years ended December 31, 2002 and 2001, $161.0 million and $81.9 million, respectively, would be reclassified from tangibles to intangibles representing costs incurred, net of accumulated amortization, since June 30, 2001, the effective date of SFAS No. 141. We will continue to classify our oil and gas leasehold costs as tangible oil and natural gas properties until further guidance is provided.

SFAS No. 143, "Accounting for Asset Retirement Obligations," addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 takes effect January 1, 2003. SFAS No. 143 requires that the fair value of a liability for an asset's retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. For all periods presented, we have included estimated future costs of abandonment and dismantlement in our full cost amortization base and amortize these costs as a component of our depletion expense.

We have completed our assessment of SFAS No. 143. At December 31, 2002, we estimate that the present value of our future Asset Retirement Obligation ("ARO") for natural gas and oil property and related equipment is approximately $57 million. We estimate that the cumulative effect of our adoption of SFAS No. 143 and the change in accounting principle will be a charge to net income during the first quarter of 2003 of $4.3 million, $2.8 million net of taxes.

In April 2002 the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, No. 44, and No. 64, Amendment to FASB Statement No. 13 and Technical Corrections." SFAS No. 145 streamlines the reporting of debt extinguishments and requires that only gains and losses from extinguishments meeting the criteria in Accounting Policies Board Opinion 30 would be classified as extraordinary. Thus, gains or losses arising from extinguishments that are part of a company's recurring operations would not be reported as an extraordinary item. SFAS No. 145 is effective for fiscal years beginning after May 15, 2002. At this time, we do not expect the adoption of SFAS No. 145 to have a material impact on our financial position, results of operations or cash flows.

SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" was issued in June 2002 and addresses accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force ("EITF") Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred. Under Issue 94-3, a liability for an exit cost was recognized at the date of an entity's commitment to an exit plan. Under SFAS No. 146, the objective for initial measurement of the liability is fair value. SFAS No. 146 is effective for exit or disposal activities that are initiated after December 31, 2002. At this time, we do not expect that the adoption of SFAS No. 146 to have a material impact on our financial position, results of operations or cash flows.

SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure" was issued in December 2002 and the transition guidance and annual disclosure provisions are effective for us for the year ended December 31, 2002. SFAS No. 148 amends SFAS Statement No. 123, "Accounting for Stock Based Compensation" and provides alternative

methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, the statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based compensation and the effect of the method used. We adopted SFAS No. 148 for 2002 and on January 1, 2003, we adopted the fair value expense recognition provisions of SFAS No. 123 on a prospective basis and as a result, we will record as compensation expense the fair value of all stock options issued subsequent to January 1, 2003.

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 2 -- LONG-TERM DEBT AND NOTES

		2002
SENIOR DEBT:		
Revolving bank credit facility, due July 15, 2005	$	152
SUBORDINATED DEBT:		
8 5/8% Senior Subordinated Notes, due January 1, 2008		100
Total long-term debt and notes	$	252

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, 2002, the quoted market value of the Company's $100 million of 8?% Senior Subordinated Notes was 103.8% of the $100 million carrying value or $103.8 million.

Principle payments due over the next five year period and thereafter are as follows.

	2003	2004	2005	2006
Revolving bank credit facility	$ --	$ --	$ 152,000	$ --
85/8% senior Subordinated Notes ...	--	--	--	--
Total maturities	$ --	$ --	$ 152,000	$ --

Credit Facility

New Credit Facility. We entered into a new revolving bank credit facility, dated as of July 15, 2002 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 new credit facility replaced our previous $250 million revolving bank credit facility, and provides us with an initial commitment of $300 million. The initial $300 million commitment 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 new credit facility is subject to borrowing base limitations and the borrowing base has been set at $300 million. Our borrowing base will be redetermined semi-annually, with the next redetermination scheduled for April 1, 2003. Up to $25 million of the borrowing base is available for the issuance of letters of credit. The new credit facility matures July 15, 2005 , is unsecured and with the exception of trade payables, ranks senior to all of our existing debt. Following the closing of the new revolving credit facility on July 18, 2002, funds were drawn on the new facility and used to repay total outstanding borrowings under the previous credit facility of $170 million. At December 31, 2002, $152 million in borrowings were outstanding under the new revolving credit facility and $0.4 million was outstanding in 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 .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.

Our revolving bank credit facility contains 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 70% of our natural gas production during any 12-month period

As of December 31, 2002, we were in compliance with all covenants.

Previous Credit Facility. We maintained our previous revolving bank credit facility with a syndicate of lenders led by JPMorgan Chase, National

Association. The credit facility, as amended, provided a maximum commitment of $250 million, subject to borrowing base limitations. Our borrowing base amount was $250 million prior to repayment. Up to $2.0 million of the borrowing base was available for the issuance of letters. The credit facility was due to mature on April 15, 2003 and was unsecured.

Interest was payable on borrowings under the previous credit facility as follows:

- o on base rate loans, at a fluctuating rate, or base rate, equal to the greater of the Federal Funds rate plus 0.5% or JP Morgan Chase's prime rate, or

- o on fixed rate loans, a fixed rate equal to a quoted LIBOR rate plus a variable margin of 0.875% to 1.625%, depending on the amount outstanding under the credit facility.

Interest was payable at calendar quarters for base rate loans and at the earlier of maturity or three months from the date of the loan for fixed rate loans. In addition, the credit facility required a commitment fee of:

- o between 0.25% and 0.375% per annum on the unused portion of the designated borrowing base, and

- o an additional fee equal to 33% of the commitment fee on the daily average amount by which the total amount of commitments exceeds the designated borrowing base.

Senior Subordinated Notes

On March 2, 1998, we issued $100 million of 8?% senior subordinated notes due January 1, 2008. The notes bear interest at a rate of 8?% per annum with interest payable semi-annually on January 1 and July 1. We may redeem the notes 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 which decreases yearly from 4.313% in 2003 to 0% in 2006. 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, if any. A "change of control" is:

- o 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;

- o 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;

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

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

The notes are general unsecured obligations and rank subordinate in right of payment to all existing and future senior debt, including the credit facility, and will rank senior or equal in right of payment to all existing and future subordinated indebtedness.

NOTE 3 -- STOCKHOLDERS' EQUITY

KeySpan Credit Facility and Conversion

On March 31, 2000, we converted $80 million of borrowings that were outstanding under a revolving credit facility with KeySpan into 5,085,177 shares of our common stock at a conversion price of $15.732 per share. The revolving credit facility was entered into in November 1998 to fund the acquisition of our Mustang Island A31/32 Field. Upon conversion on March 31, 2000, KeySpan's ownership interest in our company increased from 64% to 70%. At December 31, 2002 KeySpan's ownership in our company was 66% with the decrease attributable to an increase in our common shares outstanding due to the exercise of stock options subsequent to the conversion transaction. The conversion price was determined based upon the average of the closing prices of our common stock, rounded to three decimal places, as reported under "NYSE Composite Transaction Reports" in the Wall Street Journal during the 20 consecutive trading days ending three trading days prior to March 31, 2000. The conversion of the revolving credit facility and the corresponding issuance of additional shares of our common stock to KeySpan was approved by our stockholders at our annual meeting held April 27, 1999. Borrowings under the facility bore interest at LIBOR plus 1.4% and we incurred a quarterly commitment fee of 0.125% on the unused portion of the maximum commitment. The credit facility terminated on March 31, 2000. For the year ended December 31, 2000, we incurred $1.5 million in interest and fees to KeySpan.

NOTE 4 -- EMPLOYEE BENEFIT AND STOCK AND OPTION PLANS

Deferred Compensation Plan

In November 2002, our Board of Directors adopted a deferred compensation plan for the benefit of our employees. The plan 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 ($11,000 per year or $12,000 per year for employees over 50 years of age for 2002) 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 2002, we made matching contributions totaling $0.5 million to the deferred compensation plan. Employer contributions vest 20% per year and become fully vested after a 5 year period. All contributions to the plan are held in trust and invested, at the direction of the employee, in various investment funds, including company stock. Participants are entitled to distribution of their deferrals and the vested portion of our matching contributions at predetermined future dates or upon termination of their employment.

401(k) Profit Sharing Plan

We maintain a 401(k) Profit Sharing Plan for our employees. Under the

401(k) plan, eligible employees may elect to have us contribute on their behalf up to 12.5% of their base compensation (subject to limitations imposed under the Internal Revenue Code of 1986, as amended) 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 Service. The amounts contributed under the 401(k) plan are held in a trust and invested among various investment funds, including the Company's common stock, in accordance with the directions of each participant. An employee's salary deferral contributions under the 401(k) plan are 100% vested. Our matching contributions vest at the rate of 20% per year of service. Participants are entitled to payment of their vested account balances upon termination of employment. We made contributions to the 401(k) plan of $0.7 million, 0.7 million, and $0.6 million, respectively, for the years ended December 31, 2002, 2001 and 2000.

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, $113,000, and $123,000, respectively, during the years ended December 31, 2002, 2001 and 2000 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.

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. 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 and approved by the stockholders in May 2002. 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 non-employee directors whose options vest immediately upon grant. All grants are made at the closing 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. In addition to stock options, the 2002 Plan allows for the grant of restricted stock. In addition to stock options, the 2002 Plan currently has 300,000 shares reserved for the grant of restricted stock. As of December 31, 2002, no grants of restricted stock have been made under the 2002 Plan.

The table below summarizes all our Stock Plans at December 31, 2002.

	2002 PLAN	1999 PLAN	1996 PLAN
Options authorized	1,500,000	800,000	3,033,912
Options granted			
Incentive stock options	33,268	--	1,032,302
Non-qualified stock options	560,682	799,434	2,001,281
Total grants	593,950	799,434	3,033,583
Options available for grant	906,050	566	329
Total exercised	--	85,910	1,919,391

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

	YEARS ENDED DECEMBER 31,			
	2002		2001	
	SHARES	PRICE(1)	SHARES	PRICE
Options outstanding January 1	2,164,448	$ 24.81	1,660,745	$ 17

Granted	754,059	30.14	1,129,871	30
Exercised	(490,788)	19.70	(624,180)	16
Forfeited	(6,053)	27.77	(1,988)	29
Options outstanding December 31	2,421,666	$ 27.50	2,164,448	$ 24
Options exercisable December 31	848,103	$ 25.12	940,929	$ 21
Options available for grant December 31	906,945		155,451	

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(1) Weighted average price. 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, 2002.

Options Outstanding					Options Exer
Range of Exercise Prices	Shares Underlying Options	Year Granted	Remaining Contractual Life	Weighted Average Exercise Price	Shares Underlying Options
$15.50 - $ 17.25	105,847	1996	4 years	$ 15.53	105,847
$13.13 - $ 25.00	123,500	1997	5 years	19.90	123,500
$15.75 - $ 23.38	116,664	1998	6 years	19.10	70,386
$16.94 - $ 21.00	175,926	1999	7 years	18.94	112,446
$18.00 - $ 26.19	85,800	2000	8 years	22.65	47,100
$22.50 - $ 37.38	1,060,379	2001	9 years	30.44	360,824
$27.49 - $ 33.75	753,550	2002	10 years	30.14	28,000
	2,421,666			$ 27.50	848,103

Common stock issued through the exercise of non-qualified stock options results in a tax deduction for us that is equivalent to the compensation income recognized by the option holder. 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 2002 and 2001 resulted in a deferred tax benefit to us of approximately $4.8 million and $1.3 million for, respectively, with no deduction in 2000.

Fair Value of Employee Stock-Based Compensation

We account for the incentive stock plans using the intrinsic value method prescribed under Accounting Principles Board No. 25 and accordingly we have not recognized compensation expense for stock options granted. Had stock options been accounted for using the fair value method as recommended in SFAS No. 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, 2002, 2001 and 2000.

	YEA
	2002
	(IN THOU
Net income - as reported	$ 70,494
Add: Stock-based compensation expense included in Net income, net of tax	55
Less: Stock-based compensation expense determined using fair value method, net of tax	(3,502)
Net income - pro forma	$ 67,047
Net income per share - as reported	$ 2.31
Net income per share - fully diluted - as reported	2.28
Net income per share - pro forma	$ 2.19
Net income per share - fully diluted - pro forma	$ 2.17

The effects of applying SFAS No. 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 2002, 2001 and 2000, where the exercise price equaled the market price on the grant date were $14.08, $13.45, and $10.22, 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 2002, 2001 and 2000:

	YEARS ENDED DECEMB	
	2002	2001
Risk-free interest rate..	4.59%	5.80%
Expected years until exercise....................................	5	5
Expected stock volatility..	46%	41%
Expected dividends..	--	--

NOTE 5 -- INCOME TAXES

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

	YE
	2002
Current	(768)
Deferred	39,860
Total	$ 39,092

The credit in the current provision primarily represents Section 29 tax credits (see Note 6--Related Party Transactions - Section 29 Tax Credits). As of December 31, 2002 and 2001, we had net operating loss carryforwards for federal income tax purposes of approximately $47.5 million and $79.6 million, respectively, that may be used in future years to offset taxable income. If not utilized, these net operating losses will begin to expire in 2010.

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

	YEARS ENDED	
	2002	
		(IN T
Income before income taxes	$ 109,586	$
Statutory rate	35%	
Income tax expense computed at statutory rate	38,355	
Reconciling items:		
Section 29 tax credits and other tax credits(1)	(804)	
Non-deductible compensation expense from 2001	1,541	
Tax provision	$ 39,092	$

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(1) Year ended December 31, 2001 includes an adjustment for an under-accrual of tax expense in 2000.

Deferred Income Taxes

The components of net deferred tax liabilities pursuant to SFAS No. 109 for the years ended December 31, 2002 and 2001 primarily represent temporary differences related to depreciation of natural gas and oil properties.

Deferred tax assets:	
Derivative instruments	
Alternative minimum tax credit carryforwards	
Net operating loss carryforwards	
Total deferred tax assets	
Deferred tax liabilities:	
Property and equipment	
Derivative instruments	
Total deferred tax liabilities	
Total deferred tax asset (liability)	

NOTE 6 -- RELATED PARTY TRANSACTIONS

TRANSACTIONS WITH KEYSPAN

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 of $7.7 million in 2000 and $20.7 million during 1999. 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. In addition, we received reimbursements from KeySpan for a portion of our general and administrative costs.

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. In addition, effective with the termination of the exploratory term of the joint venture, we have not received any further reimbursement from KeySpan for general and administrative costs.

From the inception of the joint venture in January 1999 through December 31, 2002, we drilled a total of 28 wells: 21 exploratory wells of which 17 were successful and seven development wells of which six were successful. KeySpan spent a total of $118.3 million, with $19.0 million, $17.2 million and $46.5 million, respectively being spent during 2002, 2001 and 2000. Subsequent to the termination of the primary exploratory term of the joint venture, KeySpan's participation in additional wells was to further develop or delineate reservoirs previously discovered.

Acquisition of KeySpan Joint Venture Assets

On October 11, 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. 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. The interests purchased were in the following blocks: Vermilion 408, East Cameron 81 and 84, High Island 115, Galveston Island 190 and 389, Matagorda Island 704 and North Padre Island 883. KeySpan has retained its 45% interest in four blocks: South Timbalier 314 and 317 and Mustang Island 725 and 726 as these blocks are in various stages of development. KeySpan has committed to continued participation in the ongoing development of these blocks which includes the completion of the platform and production facilities at South Timbalier 314/317 together with possible further developmental drilling at both South Timbalier 314/317 and Mustang Island 725/726. As of 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 Credit Facility and Conversion (See Note 3-- Stockholders' Equity)

Review of Strategic Alternatives

In September 1999, we, along with KeySpan, our majority stockholder, announced our intention to review strategic alternatives for Houston Exploration and for KeySpan's investment in Houston Exploration. KeySpan was assessing the role of our company within its future strategic plan, and was considering a full range of strategic transactions including the sale of all or a portion of Houston Exploration. J.P. Morgan Securities Inc. was retained by KeySpan as financial advisor to assist in the strategic review on behalf of KeySpan. Our Board of Directors appointed a special committee comprised of

outside directors to assist in the review process. On February 25, 2000, together with KeySpan we jointly announced that the review of strategic alternatives had been completed and that KeySpan plans to retain its equity interest in us for the foreseeable future, however, KeySpan considers its investment in Houston Exploration a non-core asset. We incurred expenses relating to this review of strategic alternatives totaling $0.1 million during 2001 and $1.8 million during 2000.

Sale of Section 29 Tax Credits

In January 1997, we entered into an agreement to sell to a subsidiary of KeySpan interests in our onshore producing wells that produce from formations that qualify for tax credits 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. KeySpan acquired an economic interest in wells that are 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.

We manage and administer the daily operations of the properties in exchange for an annual management fee of $100,000. The income statement effect, representing benefits received from Section 29 tax credits, was a benefit of $0.8 million, respectively, for each of the years ended December 31, 2002, 2001, and 2000. The tax credits expired December 31, 2002 and under the terms of the agreement, we are required to repurchase the interests in the producing wells for KeySpan. We are planning to complete the repurchase transaction in 2003 and the repurchase price is estimated at approximately $2.0 million.

TRANSACTIONS WITH OUR EXECUTIVES

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 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 2002 and 2001 we recognized stock compensation expense of $85,000 and $64,000, respectively related to this restricted stock grant.

Employment Contracts

We have entered into employment contracts with all eight 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 welfare benefits for a specified time period.

Termination of Employment Agreements for Former Executives

Effective March 31, 2001, our President and Chief Executive Officer and Director, James G. Floyd, and our Senior Vice President - Exploration and Production, Randall J. Fleming, retired. Each had served in their respective positions since the Company's inception in 1986. In connection with their retirement as executive officers, each of Messrs. Floyd and Fleming agreed to the termination of their respective employment agreements. They received lump sum severance payments of $2.3 million and $1.4 million, respectively. Effective September 30, 2001, Thomas W. Powers, our Chief Financial Officer, left the Company to pursue other interests. In connection with the termination of his employment agreement with us, Mr. Powers received a lump sum severance payment of approximately $1.5 million. In total, the Company has incurred approximately $5.2 million in general and administrative expenses during 2001 as a result of the termination of employment contracts with former executives.

Transactions with Former President and Chief Executive Officer

Prior to January 2000 our former President and Chief Executive Officer held working interests and net profits interest in various properties of our company. These interests were acquired pursuant to the terms of his employment contract. In January 2000, we agreed to exchange all of the working interests and net profits interests Mr. Floyd had acquired in our properties for an overriding royalty interest in those same properties. During 2001 and 2000, Mr. Floyd received $6.9 million and $5.4 million (net of $0.4 million in related expenses), respectively, relating to his overriding royalty interests in our properties.

NOTE 7 -- HEDGING CONTRACTS

2002. 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 negative $38.8 million ($25.2 million net of taxes).

NATURAL GAS HEDGES	FIXED PRICE SWAPS		COLLARS	
PERIOD	VOLUME (MMBTU)	NYMEX CONTRACT PRICE	VOLUME (MMBTU)	NYMEX CONTRACT AVG FLOOR
January 2003	1,240	$ 3.194	4,495	$ 3.493
February 2003	1,120	3.194	4,060	3.493
March 2003	1,240	3.194	4,495	3.493
April 2003	1,200	3.194	4,500	3.476
May 2003	1,240	3.194	4,650	3.476

June 2003	1,200	3.194	4,500	3.476
July 2003	1,240	3.194	4,650	3.476
August 2003	1,240	3.194	4,650	3.476
September 2003	1,200	3.194	4,500	3.476
October 2003	1,240	3.194	4,650	3.476
November 2003	1,200	3.194	4,500	3.476
December 2003	1,200	$ 3.194	4,650	3.476
January 2004	--	--	1,550	3.500
February 2004	--	--	1,400	3.500
March 2004	--	--	1,550	3.500
April 2004	--	--	1,500	3.500
May 2004	--	--	1,550	3.500
June 2004	--	--	1,500	3.500
July 2004	--	--	1,550	3.500
August 2004	--	--	1,550	3.500
September 2004	--	--	1,500	3.500
October 2004	--	--	1,550	3.500
November 2004	--	--	1,500	3.500
December 2004	--	--	1,550	3.493

OIL HEDGES	FIXED PRICE SWAPS		COLLARS		
PERIOD	VOLUME (MBbl)	NYMEX CONTRACT PRICE	VOLUME (MBbl)	NYMEX CONTRACT PRICE AVG FLOOR	AVG
January 2003	31	$ 28.50	--	--	
February 2003	28	28.50	--	--	
March 2003	31	28.50	--	--	

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. 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.

During the fourth quarter of 2002, an increase in forward market prices for natural gas caused our mark-to-market exposure with one counter party to surpass our contractual margin threshold as established under the contract. As a result, we were required to post margin in the amount of $5.4 million. The margin payment earns interest at a market rate and will be refunded if our mark-to-market exposure drops below the margin threshold as required under the contract. This will occur if market prices decline from current levels. At December 31, 2002, the $5.4 million paid for the margin call is classified as restricted cash and is included in current assets on the balance sheet in the line item "Prepayments and Other."

2001. At December 31, 2001, we had entered into commodity price hedging contracts with respect to our production for 2002 and 2003 as listed in the table below. Volumes and fair values are stated in thousands. The total estimated fair value of our natural gas derivative instruments at December 31, 2001 was a positive $53.8 million ($34.9 million net of taxes).

NATURAL GAS HEDGES	FIXED PRICE SWAPS		COLLARS	
PERIOD	VOLUME (MMbtu)	NYMEX CONTRACT PRICE	VOLUME (MMbtu)	NYM CONTRACT AVG FLOOR
January 2002	930	$ 3.010	4,340	$ 3.643
February 2002	840	3.010	3,920	3.643
March 2002	930	3.010	4,340	3.643
April 2002	900	3.010	4,200	3.643
May 2002	930	3.010	4,340	3.643
June 2002	900	3.010	4,200	3.643
July 2002	930	3.010	4,340	3.643
August 2002	930	3.010	4,340	3.643
September 2002	900	3.010	4,200	3.643
October 2002	930	3.010	4,340	3.643
November 2002	900	3.010	4,200	3.643
December 2002	930	3.010	4,200	3.643
January 2003	1,240	3.194	--	--
February 2003	1,120	3.194	--	--
March 2003	1,240	3.194	--	--
April 2003	1,200	3.194	--	--
May 2003	1,240	3.194	--	--
June 2003	1,200	3.194	--	--
July 2003	1,240	3.194	--	--
August 2003	1,240	3.194	--	--
September 2003	1,200	3.194	--	--
October 2003	1,240	3.194	--	--
November 2003	1,200	3.194	--	--
December 2003	1,240	3.194	--	--

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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, 2002, 2001 and 2000 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	2002	2001	2000
Anadarko Petroleum Corporation	12.6%	7.3%	8.7
ConocoPhillips	14.9%	4.0%	0.6
KinderMorgan	9.8%	5.0%	2.8
Dynegy, Inc.	5.5%	16.4%	22.5
Adams Resources and Energy, Inc.	8.2%	12.5%	14.9
El Paso Corporation	4.8%	9.5%	9.1

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

NOTE 9 -- COMMITMENTS AND CONTINGENCIES

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. The "high-cost/tight-gas formation" designation will allow us to receive an abatement of severance taxes for qualifying wells in various fields. For qualifying wells, production will be either exempt from tax or taxed at a reduced rate until certain capital costs are recovered. For qualifying wells, we will also be entitled to a refund of severance taxes paid during a designated prior 48-month period. Applications for refund are submitted on a well-by-well basis to the State Comptroller's Office and due to timing of the acceptance of applications, we are unable to project the 48-month look-back period for qualifying refunds. We currently estimate that the total refund, for 2002 and prior periods, will be between $18 million to $23 million ($12 million to $15 million, net of tax), although we can provide no assurances that the actual total refund amount will fall within our current estimate. During the fourth quarter of 2002, we recorded refunds totaling $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.

Legal Proceedings

On August 18, 2002, a complaint styled Victor Ramirez, Santiago Ramirez, Jr., Oswaldo H. Ramirez and Javier Ramirez as Co-Trustees of the Ramirez Mineral Trust v. The Houston Exploration Company, cause number 5,207, was filed in the district court of the 49th Judicial District in Zapata County, Texas. The complaint alleges that we trespassed by drilling the No. 7 RMT well to a depth in excess of our lease rights and commingled production by producing from the excess depth. The plaintiffs claim damages for trespass and conversion in excess of $6 million and further seek to recover exemplary damages in excess of $18 million. At February 20, 2003, the issuance date of our original report, we were in the discovery stage of the litigation

process for this claim. We believe that the claim will not have a material adverse effect on our financial condition or results of operations.

Other Litigation. 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.

Leases

We have entered into non-cancellable operating lease agreements relative to the lease of our office space at 1100 Louisiana in Houston, Texas and various types of office equipment (telephones, copiers and fax machines) with various expiration dates through 2009. Minimum rental commitments under the terms of our operating leases are as follows (in thousands):

YEAR ENDED DECEMBER 31,	MINIMUM PAYMENTS
2003	$ 1,071
2004	1,124
2005	1,168
2006	1,116
2007	1,215
Thereafter	3,323

Net rental expense related to these leases was $1.2 million, $0.6 million and $0.5 million, respectively, for the years ended December 31, 2002, 2001 and 2000.

NOTE 10 -- ACQUISITIONS

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 North East 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 represents 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 North East Thompsonville Field, located in Jim Hogg County, and the South Laredo Field, located in Webb County. The North East 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 --RESTATEMENT AND RECLASSIFICATIONS

Application of EITF Issue No. 00-10 - Transportation Expense

Subsequent to the issuance of our financial statements for the year ended December 31, 2001, we determined that we had not adopted Emerging Issues Task Force Issue ("EITF") Issue No. 00-10, "Accounting for Shipping and Handling Fees and Costs" that was effective for us in the fourth quarter of 2000. EITF Issue No. 00-10 reached a consensus that amounts billed to customers for shipping and handling costs should be classified as revenues and that deducting shipping and handling costs from revenues is not appropriate and that such costs should be classified as an expense on the income statement. Furthermore, the EITF determined that upon application of this Issue, comparative financial statements for prior periods should be reclassified to comply with the guidance provided.

Previously we reflected our shipping and handling costs as a reduction to natural gas and oil revenues. In accordance with the application of EITF No. 00-10,we added these costs back to natural gas and oil revenues and reclassified them to transportation expense. Our accompanying Consolidated Statement of Operations for the year ended December 31, 2001 was restated from amounts previously reported to reflect the application of EITF No. 00-10 and the correct presentation of transportation expense. The restatement for 2001 has no effect on net income or income from operations. Our Consolidated Statement of Operations for the year ended December 31, 2000 was reflected to provide comparative financial statements for all periods presented. The reclassification for 2000 has no effect on net income or income from operations.

The table below provides a summary of the effects of application of EITF No. 00-10 for amounts reported in 2001 and 2000. See Note 13 - Selected Quarterly Information, for the effects of the application of EITF No. 00-10 for each of the quarterly periods during the years ended December 31, 2002 and 2001.

	2001		
	RESTATED	PREVIOUSLY REPORTED	RECLA

			($ IN THOUSA
Natural gas and oil revenues	$ 387,156	$ 379,504	$ 2
Total revenues	388,509	380,857	2
Transportation expenses	7,652	--	
Total operating expenses	195,994	188,342	1
Income from operations	192,515	192,515	1
Net income	122,601	122,601	

Adoption of SFAS No. 133

In connection with the adoption of SFAS No. 133, on January 1, 2001 we were required to disclose in our Consolidated Statement of Stockholders' Equity and Comprehensive Income the cumulative effect of the accounting change for derivative instruments, which is equal to the unrealized loss related to the mark-to-market valuation of our derivative instruments as of January 1, 2001 together with the value of derivative instruments settled during the period and reclassified to income during the period and the unrealized gain or loss due to the change in the fair value during the period. All amounts are to be reported net of taxes. Our Consolidated Statement of Stockholder's Equity now presents these amounts in accordance with SFAS No. 133.

NOTE 12-- SUPPLEMENTAL INFORMATION ON NATURAL GAS AND OIL EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED)

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

Capitalized Costs of Natural Gas and Oil Properties

As of December 31, 2002, 2001 and 2000, our capitalized costs of natural gas and oil properties are as follows:

	AS OF DECEMBER 3	
	2002	2001
		(IN THOUSANDS
Unevaluated properties, not amortized	$ 96,192	$ 177,9
Properties subject to amortization	1,828,160	1,493,2
Capitalized costs	1,924,352	1,671,2
Accumulated depreciation, depletion and amortization	(906,089)	(735,2

Net capitalized costs	$ 1,018,263	$ 936,0

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, 2002, 2001 and 2000 include interest expense and general and administrative costs related to acquisition, exploration and development of natural gas and oil properties of $21.1 million, $24.9 million and $23.3 million, respectively.

	AS
	2002
	(
Property acquisition and leasehold costs	
Unevaluated(1)	$ 14,600
Proved	89,873
Exploration costs	26,563
Development costs	122,036
Total costs incurred	$ 253,072

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(1) These amounts represent costs we incurred during 2002 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.

During the years ended December 2002, 2001 and 2000, we spent $11.0 million, $19.9 million and $9.7 million, respectively to develop our proved undeveloped reserves. At December 31, 2002, 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 $141.8 million, $31.9 million and $7.0 million, respectively, for 2003, 2004 and 2005.

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 percent.

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

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

	AS
	2002

		(
Future cash inflows	$ 2,845,768	$
Future production costs	(486,399)	
Future development costs	(241,876)	
Future income taxes	(542,782)	
Future net cash flows	1,574,711	
10% annual discount for estimated timing of cash flows	(516,647)	
Standardized measure of discounted future net cash flows	$ 1,058,064	$

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

	AS OF DEC	
	2002	20
		(IN THO
Beginning of the year	$ 551,525	$ 2,0
Revisions to previous estimates:		
Changes in prices and costs	629,542	(2,0
Changes in quantities	(36,368)	(
Changes in future development costs	(1,970)	(
Development costs incurred during the period	23,393	
Extensions and discoveries, net of related costs	242,055	1
Sales of natural gas and oil, net of production costs	(275,157)	(3
Accretion of discount	64,858	2
Net change in income taxes	(209,807)	6
Purchase of reserves in place	99,741	
Sale of reserves in place	(170)	
Production timing and other	(29,578)	(1
End of year	$ 1,058,064	$ 5

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Estimated Net Quantities of Natural Gas and Oil Reserves (Unaudited)

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, 2002, 2001 and 2000.

NATURAL GAS	C

	(MMcf)			
	2002	2001	2000	2002
Proved developed and undeveloped reserves:	568,208	529,518	526,185	6,60
Revisions of previous estimates ...	(14,863)	(41,914)	3,709	(2
Extensions and discoveries	105,798	83,551	69,564	34
Production	(97,368)	(87,095)	(77,861)	(85
Purchase of reserves in place	48,777	84,148	7,921	48
Sales of reserves in place	(143)	--	--	(1
End of year	610,409	568,208	529,518	6,53
Proved developed reserves:				
Beginning of year	438,538	420,733	397,343	2,12
End of year	435,629	438,538	420,733	2,41

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 13-- QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	1ST QUARTER	2ND QUARTER	3
		(IN THOUSANDS, EXCE	
2002			
Total revenues - restated	$ 74,816	$ 85,955	$
Total revenues - previously reported (1)	72,640	83,728	
Total operating expenses - restated	54,425	57,426	
Total operating expenses - previously reported (1) ...	52,249	55,209	
Income from operations	20,391	28,519	
Net income	12,534	17,654	
Net income per share(2)	$ 0.41	0.58	
Net income per share--fully diluted(2)	$ 0.41	0.57	
2001			
Total revenues - restated	$ 126,418	$ 101,151	$
Total revenues - previously reported (1)	124,342	99,308	
Total operating expenses - restated	75,199	56,876	
Total operating expenses - previously reported (1) ...	49,143	42,432	
Income from operations	75,199	56,876	
Net income	47,344	35,855	
Net income per share(2)	$ 1.58	$ 1.19	$
Net income per share--fully diluted(2)	$ 1.55	$ 1.17	$

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(1) For all periods presented, we applied Emerging Issues Task Force ("EITF") No. 00-10 "Accounting for Shipping and Handling Fees and Costs." Pursuant our application of EITF No. 00-10, transportation expenses previously reflected as a reduction to natural gas and oil revenues were added back to revenues and reported as a separate component of operating expense. The application of EITF No. 00-10 has no effect on income from operations or net income. See Note 11 - Restatement and Reclassifications made to Statements of Operations for Transportation Expense.

(2) 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.

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 March 2, 1998, between The Houston Exploration Company and The Bank of New York, as Trustee, with respect to the 85/8% Senior Subordinated Notes Due 2008 (including form of 85/8% Senior Subordinated Note Due 2008) (incorporated by reference to Exhibit 4.1 to our Registration Statement on Form S-4 (No. 333-50235)).
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 between The Houston Exploration Company and Smith Offshore Exploration Company (filed as Exhibit 10.15 to our Registration Statement on Form S-1 (Registration No. 333-4437) and incorporated by reference).

10.3		Subordinated Loan Agreement dated November 30, 1998 between The Houston Exploration Company and MarketSpan Corporation d/b/a KeySpan Energy Corporation (filed as Exhibit 10.30 to our Annual Report on Form 10-K for the year ended December 31, 1998 and incorporated by reference).
10.4		Subordination Agreement dated November 25, 1998 entered into and among MarketSpan Corporation d/b/a KeySpan Energy Corporation, The Houston Exploration Company and Chase Bank of Texas, National Association (filed as Exhibit 10.31 to our Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 001-11899) and incorporated by reference).
10.5		First Amendment to Subordinated Loan Agreement and Promissory Note between KeySpan Corporation and The Houston Exploration Company dated effective as of October 27, 1999 (filed as Exhibit 10.17 to our Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 001-11899) and incorporated by reference).
10.6	--	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).
10.7	--	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).
10.8	--	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).
10.9(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).
10.10(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).
10.11(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).
10.12(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).
10.13(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).
10.14(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).
10.15(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).

INDEX TO EXHIBITS

EXHIBITS		DESCRIPTION
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)	--	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).
10.26(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).
10.27(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).
10.28(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).
10.29(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).
12.1	--	Computation of ratio of earnings to fixed charges (incorporated by reference from Exhibit 12.1 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).
21.1	--	Subsidiaries of Houston Exploration (incorporated by

		reference from Exhibit 21.1 to our the original filing on February 20, 2003 of Annual Report on Form 10-K for the year ended December 30, 2002 File No. 001-11899).
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.

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(1) Filed herewith.

(2) Management contract or compensation plan.