HOUSTON EXPLORATION CO
Form 10-Q
May 05, 2003

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

FORM 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934

FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2003

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	22-2674487
(STATE OR OTHER JURISDICTION OF INCORPORATION OR ORGANIZATION)	(IRS EMPLOYER IDENTIFICATION NO.)

1100 LOUISIANA STREET, SUITE 2000
HOUSTON, TEXAS 77002-5215
(ADDRESS OF PRINCIPAL EXECUTIVE OFFICES AND ZIP CODE)
(713) 830-6800
(REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE)

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 whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes [X] No [ ]

As of May 5, 2003, 30,968,118 shares of Common Stock, par value $.01 per share, were outstanding.

THE HOUSTON EXPLORATION COMPANY

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FACTORS AFFECTING FORWARD LOOKING STATEMENTS

All of the estimates and assumptions contained in this Quarterly 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 2. 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 Quarterly Report. These factors include, among other things, the volatility of natural gas and oil prices, the requirement to take writedowns 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 our Annual Report on Form 10-K.

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

PART I. FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

THE HOUSTON EXPLORATION COMPANY
CONSOLIDATED BALANCE SHEETS
(IN THOUSANDS, EXCEPT SHARE DATA)

	MARCH 31, 2003
ASSETS:	
Cash and cash equivalents	$ 5,586
Accounts receivable	140,063
Accounts receivable -- Affiliate	7,730
Inventories	1,616
Prepayments and other	2,083
Total current assets	157,078
Natural gas and oil properties, full cost method	
Unevaluated properties	88,831
Properties subject to amortization	1,933,776
Other property and equipment	11,039
	2,033,646
Less: Accumulated depreciation, depletion and amortization	(947,930)
	1,085,716
Other assets	5,930

TOTAL ASSETS	$ 1,248,724
LIABILITIES:	
Accounts payable and accrued expenses	$ 91,887
Derivative financial instruments	52,153
Asset retirement obligation	4,446
Total current liabilities	148,486
Long-term debt and notes	230,000
Derivative financial instruments	4,423
Deferred federal income taxes	184,707
Asset retirement obligation	55,954
Other deferred liabilities	1,985
TOTAL LIABILITIES	625,555
COMMITMENTS AND CONTINGENCIES (SEE NOTE 3)	
STOCKHOLDERS' EQUITY:	
Common Stock, $.01 par value, 50,000,000 shares authorized and 30,965,118 shares issued and outstanding at March 31, 2003 and 30,954,018 shares issued and outstanding at December 31, 2002, respectively	310
Additional paid-in capital	353,688
Unearned compensation	(86)
Retained earnings	306,031
Accumulated other comprehensive income	(36,774)
TOTAL STOCKHOLDERS' EQUITY	623,169
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 1,248,724

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

THE HOUSTON EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
(IN THOUSANDS, EXCEPT PER SHARE DATA)

	THREE MONTHS ENDED MA	
	2003	2
		(as r
REVENUES:		
Natural gas and oil revenues	$ 128,398	$
Other	605	

Total revenues	129,003	
OPERATING EXPENSES:		
Lease operating	11,646	
Severance tax	4,305	
Transportation expense	2,492	
Asset retirement accretion expense	826	
Depreciation, depletion and amortization	45,654	
General and administrative, net	3,884	
Total operating expenses	68,807	
Income from operations	60,196	
Other (income) and expense	(10,578)	
Interest expense, net	2,266	
Income before income taxes	68,508	
Provision for federal income taxes	24,039	
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	$ 44,469	$
Cumulative effect of change in accounting principle, net of tax	(2,772)	
NET INCOME	$ 41,697	$
EARNINGS PER SHARE:		
NET INCOME PER SHARE - BASIC		
Income before cumulative effect of change in accounting principle	$ 1.44	$
Cumulative effect of change in accounting principle, net of tax	(0.09)	
Net income per share - basic	$ 1.35	$
NET INCOME PER SHARE - FULLY DILUTED		
Income before cumulative effect of change in accounting principle	$ 1.43	$
Cumulative effect of change in accounting principle, net of tax	(0.09)	
Net income per share - fully diluted	$ 1.34	$
Weighted average shares outstanding	30,960	
Weighted average shares outstanding -- fully diluted	31,069	

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

THE HOUSTON EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(IN THOUSANDS)

	THREE MONTHS ENDED MARCH	
	2003	200
OPERATING ACTIVITIES:		
Net income	$ 41,697	$ 12
Adjustments to reconcile net income to net cash provided by Operating activities:		
Depreciation, depletion and amortization	45,654	39
Asset retirement accretion expense	826	
Deferred income tax expense	23,981	6
Stock compensation expense	35	
Cumulative effect of change in accounting principle, net of tax	2,772	
Changes in operating assets and liabilities:		
Increase in accounts receivable	(63,374)	(14
Increase in inventories	(184)	
Decrease in prepayments and other	5,513	1
(Increase) decrease in other assets	(8,519)	1
Decrease (increase) in other liabilities	868	
Decrease (increase) in accounts payable and accrued expenses	13,712	(14
Net cash provided by operating activities	62,981	33
INVESTING ACTIVITIES:		
Investment in property and equipment	(53,646)	(47
Dispositions	--	
Net cash used in investing activities	(53,646)	(47
FINANCING ACTIVITIES:		
Proceeds from long term borrowings	18,000	9
Repayments of long term borrowings	(40,000)	(4
Proceeds from issuance of common stock	79,420	
Repurchase of common stock	(79,200)	
Net cash used in financing activities	(21,780)	5
Decrease (increase) in cash and cash equivalents	(12,445)	(8
Cash and cash equivalents, beginning of period	18,031	8
Cash and cash equivalents, end of period	$ 5,586	$
Cash paid for interest	$ 5,564	$ 5
Cash paid for taxes	$ --	$

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

THE HOUSTON EXPLORATION COMPANY
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

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 offshore operations are focused in the shallow waters of the Gulf of Mexico and our onshore core operations are focused in South Texas and in the Arkoma Basin with additional production located in East Texas, South Louisiana and West Virginia.

Principles of Consolidation

The consolidated financial statements include the accounts of The Houston Exploration Company and its wholly owned subsidiary, Seneca Upshur Petroleum Company (collectively the "Company"). All significant intercompany balances and transactions have been eliminated.

Interim Financial Statements

Our balance sheet at March 31, 2003 and the statements of operations and cash flows for the periods indicated herein have been prepared without audit, pursuant to the rules and regulations of the Securities and Exchange Commission. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States ("GAAP") have been condensed or omitted, although we believe that the disclosures contained herein are adequate to make the information presented not misleading. The balance sheet at December 31, 2002 is derived from the December 31, 2002 audited financial statements, but does not include all disclosures required by accounting principles generally accepted in the United States. The Interim Financial Statements should be read in conjunction with the Consolidated Financial Statements and Notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2002.

In the opinion of our management, all adjustments, consisting of normal recurring accruals, necessary to present fairly the information in the accompanying financial statements have been included. The results of operations for such interim periods are not necessarily indicative of the results for the full year.

Use of Estimates and Restatements

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 for the three months ended March 31, 2002 were added back to revenues and reflected as a separate component of operating expense and accordingly, the Statement of Operations has been restated for the three months ended March 31, 2002. The application of EITF No. 00-10 has no effect on income from operations or net income. The table below provides a summary of the effects of application of EITF No. 00-10 for amounts reported in for the three month period ended March 31, 2002.

	Three Months Ended March 31, 2002	
	Restated	Previously Reported
	($ in thousands)	
Natural gas and oil revenues	$ 74,622	$ 72,446
Total revenues	74,816	72,640
Transportation expenses	2,176	--
Total operating expenses	54,425	52,249
Income from operations	20,391	20,391
Net income	12,534	12,534
Natural gas price:		
Average realized price (per Mcf)	$ 2.99	$ 2.90
Average unhedged price (per Mcf)	2.28	2.19

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the 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.

Derivative Instruments

Our hedges are designated cash flow hedges and qualify for hedge accounting under Statements of Financial Accounting Standards ("SFAS") No. 133, as amended, "Accounting for Derivative Instruments and Hedging Activities" and accordingly, we carry the fair market value of our derivative instruments on the balance sheet as either an asset or liability and defer unrealized gains or losses in accumulated other comprehensive income. Gains and losses are reclassified from accumulated other comprehensive income to the income statement as a component of natural gas and oil revenues in the period the hedged production occurs. If any ineffectiveness occurs, amounts are recorded directly to other income or expense.

Net Income Per Share

Basic earnings per share ("EPS") 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. Diluted EPS assumes the conversion of all potentially dilutive securities and is calculated by dividing net income, as adjusted, by the weighted average number of shares of common stock outstanding, plus all potentially dilutive securities.

	THREE MONTHS ENDED	
	2003	
	(IN THOUSANDS, EXCEPT P	
NUMERATOR:		
Income before cumulative effect of change in accounting principle	$ 44,469	$
Cumulative effect of change in accounting principle, net of tax	(2,772)	
Net income	$ 41,697	$
DENOMINATOR:		
Weighted average shares outstanding	30,960	
Add dilutive securities: Options	109	
Total weighted average shares outstanding and dilutive securities	31,069	
EARNINGS PER SHARE - BASIC:		
Income before cumulative effect of change in accounting principle	$ 1.44	$
Cumulative effect of change in accounting principle, net of tax	(0.09)	
Net income per share - basic	$ 1.35	$
EARNINGS PER SHARE - FULLY DILUTED:		
Income before cumulative effect of change in accounting principle	$ 1.43	$
Cumulative effect of change in accounting principle, net of tax	(0.09)	
Net income per share - fully diluted	$ 1.34	$

For the three months ended March 31, 2003 and 2002, the calculation of shares outstanding for fully diluted EPS does not include the effect of outstanding stock options to purchase 1,903,561 and 1,255,343 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.

Comprehensive Income (Loss)

The table below summarizes our comprehensive income for the three months ended March 31, 2003 and 2002. Comprehensive income consists of net income and other gains and losses affecting stockholders' equity that, under GAAP, are excluded from net income. For our company, other comprehensive income consists only of unrealized gain or loss, net of tax effects, of the change in the fair market value of our derivative instruments from period to period.

THE HOUSTON EXPLORATION COMPANY
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

	THREE MONTHS ENDED MARCH 31,	
	2003	2002

	(IN THOUSANDS)	
Net income	$ 41,697	$ 12,534
Other comprehensive income, net of taxes:		
Unrealized loss on derivative instruments	(11,573)	(33,567)
Comprehensive income (loss)	$ 30,124	$ (21,033)

Stock Option Expense

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." Under the fair value method, compensation expense for stock options is recognized when stock options are issued. SFAS No. 148 proposes three alternative transition methods for a voluntary change to 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, we now recognize as compensation expense the fair value of all stock options issued subsequent to December 31, 2002. For the three months ended March 31, 2003, we recognized compensation expense of $14,000 for stock options granted during the period.

Prior to our January 1, 2003 adoption of SFAS No. 123, we accounted for the incentive stock plans using the intrinsic value method prescribed under Accounting Principles Board Opinion No. 25 and accordingly we did not recognize 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 three months ended March 31, 2003 and 2002.

	THREE MONTHS EN
	2003
	($ in thousan share a
Net income - as reported	$ 41,697
Add: Stock-based compensation expense included in net income, net of tax	23
Less: Stock-based compensation expense using fair value method, net of tax	(1,095)
Net income - pro forma	$ 40,625

Net income per share - as reported	$	1.35
Net income per share - fully diluted - as reported		1.34
Net income per share - pro forma	$	1.31
Net income per share - fully diluted - pro forma		1.31

Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations," which addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. For us, asset retirement obligations represent the systematic, monthly accretion and depreciation of future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and other facilities. SFAS 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 if a reasonable estimate of fair value can be made, and that the corresponding cost is capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. Under our previous accounting method, we included estimated future costs of abandonment and dismantlement in our full cost amortization base and amortized these costs as a component of our depletion expense.

Pursuant to the January 1, 2003 adoption of SFAS No. 143 we:

- recognized a charge to income during the first quarter of 2003 of $2.8 million, net of tax, for the cumulative effect of the change in accounting principle;
- increased our total liabilities by $57.2 million to record the asset retirement obligations ("ARO");
- increased our assets by $42.5 million to add the asset retirement costs to the carrying amount of our natural gas and oil properties; and
- reduced our accumulated depreciation, depletion and amortization by $10.4 million for the amount of expense previously recognized.

Adopting SFAS No. 143 had no impact on our reported cash flows. The following table describes on a pro forma basis our asset retirement liability as if SFAS No. 143 had been adopted on January 1, 2002.

	2003	2002
ARO liability at January 1, ...	$ 57,197	$ 45,759
Additions from drilling	2,377	2,198
ARO accretion expense	826	661
ARO liability at March 31, ...	$ 60,400	$ 48,619

The following table describes the pro forma effect on net income and earnings per share for the three months ended March 31, 2002 as if SFAS No. 143 had been adopted on January 1, 2002.

	Three Months Ended March 31, 2002
Net income - as reported	$ 12,534
Less: ARO accretion expense, net of tax	(430)
Net income - pro forma	$ 12,104
Earnings per share:	
Basic - as reported	$ 0.41
Fully diluted - as reported	0.41
Basic - pro forma	0.40
Fully diluted pro forma	0.39

Recent Accounting Pronouncements

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 No. 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. Our adoption of SFAS No. 145 on January 1, 2003 had no effect on our financial statements.

In June 2002, FASB issued SFAS No. 146, "Accounting for Costs

Associated with Exit or Disposal Activities" which addresses accounting and reporting for costs associated with exit or disposal activities and nullifies 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. Our adoption of SFAS No. 146 on January 1, 2003 had no effect on our financial statements.

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

NOTE 2 -- LONG-TERM DEBT AND NOTES

	MARCH 31, 2003	DECEMBER 31,
	(IN THOUSANDS)	
SENIOR DEBT:		
Bank revolving credit facility, due 2005.........	$ 130,000	$ 15
SUBORDINATED DEBT:		
8 5/8 Senior Subordinated Notes, due 2008........	100,000	10
Total long-term debt and notes.............	$ 230,000	$ 25

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 March 31, 2003, the quoted market value of our $100 million of 8 5/8 Senior Subordinated Notes was 99.9% of the $100 million carrying value or $99.9 million.

Revolving Bank Credit Facility

We maintain a revolving bank credit facility with a syndicate of lenders led by Wachovia Bank, National Association, as issuing bank and administrative agent, The Bank of Nova Scotia and Fleet National Bank as co-syndication agents and BNP Paribas as documentation agent. The credit facility provides us with a commitment of $300 million which may be increased at our request and with prior approval from Wachovia to a maximum of $350 million by adding one or more lenders or by allowing one or more lenders to increase their commitments. The credit facility is subject to borrowing base limitations. Our current borrowing base is $300 million and is redetermined semi-annually, with the next redetermination scheduled for October 1, 2003. Up to $25 million of the borrowing base is available for the issuance of letters of credit. The credit facility matures July 15, 2005, is unsecured and with the exception of trade payables, ranks senior to all of our existing debt. At March 31, 2003, $130 million in borrowings were outstanding under the credit facility and $15.5 million was outstanding in letter of credit obligations. Subsequent to March 31, 2003, we repaid a net $35 million under the facility

and reduced our letter of credit obligations to $9.4 million. Currently, outstanding borrowings and letter of credit obligations under our revolving bank credit facility total $104.4 million.

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

Senior Subordinated Notes

On March 2, 1998, we issued $100 million of 8 5/8 senior subordinated notes due January 1, 2008. The notes bear interest at a rate of 8 5/8 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:

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

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

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

- if, during any period of two consecutive years, individuals who at the beginning of the period constituted our board of directors, including any new directors who were approved by a majority vote of 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 -- 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 will be between $18 million to $24.5 million ($12 million to $15.9 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) and during the first quarter of 2003, we recorded refunds totaling $10.6 million ($6.9 million net of tax) for total refunds recorded of $21.0 million ($13.7 million net of tax). Currently, we estimate that we could record additional refunds of up to $3.5 million ($2.3 million net of tax). Our receivables at March 31, 2003 include $26.4 million in gross refunds of which approximately $18.5 million relates to our working interest with the balance owed to third party royalty interests.

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. We are currently unable to predict the outcome of the claim.

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

NOTE 4 -- RELATED PARTY TRANSACTIONS

Issuance of 3,000,000 Shares to the Public and Concurrent Repurchase of 3,000,000 Shares from KeySpan

In connection with our initial public offering in September 1996, we entered into a registration rights agreement with KeySpan pursuant to which we are obligated, at KeySpan's election, to facilitate KeySpan's sale of its shares of Company stock by registering the shares under the Securities Act of 1933 and assisting in KeySpan's selling efforts. During February of 2003, KeySpan notified us of its desire to sell 3,000,000 shares of their Company stock. For the mutual convenience of the parties, we elected to effect KeySpan's sale through our pre-existing registration statement rather than filing a separate, new registration statement for KeySpan. To accomplish the transaction, we simultaneously sold 3,000,000 newly issued shares of Company stock in a public offering for net proceeds of $26.40 per share, or an aggregate $79.2 million, and bought a like number of KeySpan's shares of Company stock for the same price per share. We cancelled the 3,000,000 shares acquired from KeySpan immediately following the repurchase. KeySpan reimbursed us for all costs and expenses, and the transaction had no impact on our capitalization. The transaction was evidenced in a stock purchase agreement, dated February 26, 2003. Our Board of Directors approved the transaction in principle and delegated to a special, independent committee of the Board plenary authority to negotiate the terms of, and finally approve or veto, the transaction. In finally approving the terms of the stock purchase agreement, the independent committee determined that the agreement was consistent with our pre-existing obligations under our registration rights agreement and that issuing the shares under our existing registration statement was in the best interests of our public stockholders to facilitate the prompt and orderly disposition of the shares. As a result of the transactions, KeySpan's interest in our outstanding shares decreased from 66% to 56%.

THE HOUSTON EXPLORATION COMPANY
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

Acquisition of KeySpan Joint Venture Assets

In October 2002, we purchased from KeySpan a portion of the assets developed under the joint exploration agreement with KeySpan Exploration & Production, LLC, a subsidiary of KeySpan (see below discussion of KeySpan Joint Venture). The acquisition consisted of interests averaging between 11.25% and 45% in 17 wells covering eight of the twelve blocks that were developed under the joint exploration agreement from 1999 through 2002. 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 totaled $1.2 million. 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. For assistance, the special committee retained special outside legal counsel as well as the financial advisory firm of Petrie Parkman & Co. 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. The special committee also took into account the opinion delivered to it by Petrie Parkman & Co. to the effect that the consideration to be paid by us in the transaction was fair to us from a financial point of view.

KeySpan Joint Venture

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

Effective December 31, 2000, KeySpan and Houston Exploration agreed to end the primary or exploratory term of the joint venture. As a result, KeySpan has not participated in any of our offshore exploration prospects unless the project involved the development or further exploitation of discoveries made during the initial term of the joint venture. During the first three months of 2003 and 2002, KeySpan spent approximately $3 million and $9.5 million, respectively, for capital costs associated with its working interests in properties developed under the joint venture.

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 terms of the agreement expired December 31, 2002 and as a result, we are required to repurchase the interests in the producing wells from KeySpan. Subsequent to the repurchase, ownership of the tax credits will revert back to us. We are planning to complete the repurchase transaction in 2003 and the repurchase price is estimated at approximately $2.0 million. The income statement effect, representing benefits received from Section 29 tax credits, was a benefit of $0.2 million for the three month ended March 31, 2002, with no benefit for 2003.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion is intended to assist in an understanding of our historical financial position and results of operations for the three months ended March 31, 2003 and 2002. Our consolidated financial statements and notes thereto included elsewhere in this report contains detailed information that should be referred to in conjunction with the following discussion.

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 offshore operations are focused in the shallow waters of the Gulf of Mexico and our onshore core operations are focused in South Texas and in the Arkoma Basin with additional production located in East Texas, South Louisiana and West Virginia.

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 principle 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 34% of our shares to the public, with KeySpan retaining the balance. As of March 31, 2003, THEC Holdings Corp., an indirect wholly owned subsidiary of KeySpan, owned approximately 56% 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.

Derivative Instruments. Our hedges are designated cash flow hedges and qualify for hedge accounting under Statement of Financial Accounting Standards ("SFAS") No. 133, as amended, "Accounting for Derivative Instruments and Hedging Activities" and, accordingly, we carry the fair market value of our derivative instruments on the balance sheet as either an asset or liability and defer unrealized gains or losses in accumulated other comprehensive income. Gains and losses are reclassified from accumulated other comprehensive income to the income statement as a component of natural gas and oil revenues in the period the hedged production occurs. If any ineffectiveness occurs, amounts are recorded directly to 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

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depletion rate. The depletion rate is determined by dividing our total unamortized cost base by net equivalent proved reserves at the beginning of the quarter. Our total unamortized cost base is the sum of our:

- full cost pool; plus,
- estimates for future development costs; less,
- unevaluated properties and their related costs; less,
- estimates for salvage.

Costs associated with unevaluated properties are excluded from the amortization base until we have made a determination as the existence of proved reserves. We review our unevaluated properties at the end of each quarter to determine whether the costs incurred should be reclassified to the full cost pool and thereby subject to amortization. Sales of natural gas and oil properties are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves.

Under full cost accounting rules, total capitalized costs are limited to a ceiling equal to the present value of future net revenues, discounted at 10% per annum, plus the lower of cost or fair value of unproved properties less income tax effects (the "ceiling limitation"). We perform a quarterly ceiling test to evaluate whether the net book value of our full cost pool exceeds the ceiling limitation. If capitalized costs (net of accumulated depreciation, depletion and amortization) less 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 principles generally accepted in the United States of America ("GAAP") 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

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." Under the fair value method, compensation expense for stock options is recognized when stock options are issued. SFAS No. 148 proposes three alternative transition methods for a voluntary change to the fair value method under SFAS No. 123. We adopted SFAS No. 123 using the Prospective Method as defined by SFAS No. 148, and as a result, we now recognize as compensation expense the fair value of all stock options issued subsequent to December 31, 2002 with no expense recognized for options issued in previous periods. For the three months ended March 31, 2003, we recognized compensation expense of $14,000 for stock options granted during the period. Prior to our January 1, 2003 adoption of SFAS No. 123, we accounted for the incentive stock plans using the intrinsic value method prescribed under Accounting Principles Board Opinion No. 25, and accordingly, we did not recognize compensation expense for stock options granted.

Accounting for Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations," which addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. For us, asset retirement obligations represent the systematic, monthly accretion and depreciation of future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and other facilities. SFAS 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 if a reasonable estimate of fair value can be made, and that the corresponding cost is capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. Under our previous accounting method, we included estimated future costs of abandonment and dismantlement in our full cost amortization base and amortized these costs as a component of our depletion expense.

Pursuant to the January 1, 2003 adoption of SFAS No. 143 we:

o recognized a charge to income during the first quarter of 2003 of $2.8 million, net of tax, for the cumulative effect of the change in accounting principle;

o increased our total liabilities by $57.2 million to record the asset retirement obligations ("ARO");

o increased our assets by $42.5 million to add the asset retirement costs to the carrying amount of our natural gas and oil properties; and

o reduced our accumulated depreciation, depletion and amortization by $10.4 million for the amount of expense previously recognized.

Adopting SFAS No. 143 had no impact on our reported cash flows.

Recent Accounting Pronouncements

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 No. 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. Our adoption of SFAS No. 145 on January 1, 2003 had no effect on our financial statements.

In June 2002, FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" which 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. Our adoption of SFAS No. 146 on January 1, 2003 had no effect on our financial statements.

In November 2002, FASB issued Financial Interpretation ("FIN") No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." FIN 45 requires certain guarantees to be recorded at fair value, which is different from the current practice of recording a liability only when a loss is probable and reasonably estimable, as those terms are defined in SFAS No. 5, "Accounting for Contingencies." FIN 45

has a dual effective date. The initial recognition and measurement provisions are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure requirements in the interpretation are effective for financial statements for interim or annual periods ending after December 15, 2002. As of our December 31, 2002 and March 31, 2003 balance sheet dates, we did not have any guarantees of indebtedness of others and as a result, our adoption of FIN 45 did not have an effect on our financial statements.

Issuance of 3,000,000 Shares to the Public and Concurrent Repurchase of 3,000,000 Shares from KeySpan

In connection with our initial public offering in September 1996, we entered into a registration rights agreement with KeySpan pursuant to which we are obligated, at KeySpan's election, to facilitate KeySpan's sale of its shares of Company stock by registering the shares under the Securities Act of 1933 and assisting in KeySpan's selling efforts. During February of 2003, KeySpan notified us of its desire to sell 3,000,000 shares of their Company stock. For the mutual convenience of the parties, we elected to effect KeySpan's sale through our pre-existing registration statement rather than filing a separate, new registration statement for KeySpan. To accomplish the transaction, we simultaneously sold 3,000,000 newly issued shares of Company stock in a public offering for net proceeds of $26.40 per share, or an aggregate $79.2 million, and bought a like number of KeySpan's shares of Company stock for the same price per share. We cancelled the 3,000,000 shares acquired from KeySpan immediately following the repurchase. KeySpan reimbursed us for all costs and expenses, and the transaction had no impact on our capitalization. The transaction was evidenced in a stock purchase agreement, dated February 26, 2003. Our Board of Directors approved the transaction in principle and delegated to a special, independent committee of the Board plenary authority to negotiate the terms of, and finally approve or veto, the transaction. In finally approving the terms of the stock purchase agreement, the independent committee determined that the agreement was consistent with our pre-existing obligations under our registration rights agreement and that issuing the shares under our existing registration statement was in the best interests of our public stockholders to facilitate the prompt and orderly disposition of the shares. As a result of the transactions, KeySpan's interest in our outstanding shares decreased from 66% to 56%.

As KeySpan has announced in the past, it does not consider certain businesses contained in its energy investments segment, including its investment in Houston Exploration, a part of its core asset group. KeySpan has stated in the past that it may sell or otherwise dispose of all or a portion of its non-core assets, including all or a portion of its common stock ownership in our company. As stated above, on February 20, 2003 KeySpan sold to us 3,000,000 shares of our common stock it owned, reducing its ownership percentage from approximately 66% to 56%. KeySpan has stated that based on market conditions, it cannot predict when, or if, any additional sales or dispositions of all or a part of its remaining ownership interest in us may take place.

RESULTS OF OPERATIONS

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

	THREE MONTHS ENDED MARCH 31, 2003	2002
PRODUCTION:		
Natural gas (MMcf)	24,385	23,895
Oil (MBbls)	257	160
Total (MMcfe)	25,927	24,855
Average daily production (MMcfe/day)	288	276
AVERAGE SALES PRICES:		
Natural gas (per Mcf) realized(1)	$ 4.93	$ 2.99
Natural gas (per Mcf) unhedged	6.36	2.28
Oil (per Bbl) realized(1)	31.57	19.28
Oil (per Bbl) unhedged	33.42	19.28
OPERATING EXPENSES (PER MCFE):		
Lease operating	$ 0.45	$ 0.30
Severance tax	0.17	0.07
Transportation	0.10	0.09
Asset retirement obligation accretion	0.03	--
Depreciation, depletion and amortization	1.76	1.60
General and administrative, net	0.15	0.13

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(1) Realized natural gas and oil prices include the effects of hedging.

RECENT FINANCIAL AND OPERATING RESULTS

COMPARISON OF THREE MONTHS ENDED MARCH 31, 2003 AND 2002

Production. Our production increased 4% from 24,855 million cubic feet equivalent, or MMcfe, for the three months ended March 31, 2002 to 25,927 MMcfe for the three months ended March 31, 2003. Average daily production was 288 MMcfe/day during the first quarter of 2003 compared to 276 MMcfe/day during the first quarter of 2002.

Onshore, our daily production rates increased 22% from an average of 142 MMcfe/day during the first quarter of 2002 to an average of 173 MMcfe/day during the corresponding three months of 2003. The increase in onshore production is primarily attributable to 32 MMcfe/day in newly developed production from our Alexander and Hubbard fields in South Texas that were acquired in December 2001 from Conoco Inc. together with 12 MMcfe/day in production from properties acquired in May 2002 in the North East Thompsonville and South Laredo fields in South Texas from Burlington Resources. These increases were offset in part by a decline of 13 MMcfe/day in all other onshore areas with the Charco Field comprising 8 MMcfe/day of the decrease and our Arkoma properties comprising 3 MMcfe/day of the decrease. The Charco Field produced at an average rate of 87 MMcfe/day during the first quarter of 2002 compared to an average of 79 MMcfe/day during the first quarter of 2003. Our Arkoma properties produced at an average rate of 23 MMcfe/day during the first quarter of 2002 as compared to 20 MMcfe/day during the first quarter of 2003.

Offshore, our production decreased 14% from an average of 134 MMcfe/day during the first quarter of 2002 to an average of 115 MMcfe/day during the first quarter of 2003. Production declines due to maturing reservoirs from existing key fields, Mustang Island A-31/32, High Island 39, West Cameron 587 and South Marsh Island 253, were greater than incremental production added from new wells and facilities brought on-line since the end of the first quarter of 2002 at Vermilion 408, East Cameron 81, East Cameron 82/83, Mustang Island 785, High Island 38, and South Timbalier 314/317. Further, we experienced a loss of an estimated 3 MMcfe/day at Vermilion 408 during a 15 day shut-in during January and February 2003 due to down stream pipeline shut-ins for repairs. The year-over-year production decline is partially the result of shifting approximately $40 million of our 2002 offshore capital expenditure program to our onshore region to facilitate the May 2002 acquisition of producing properties in South Texas from Burlington Resources.

Natural Gas and Oil Revenues. Natural gas and oil revenues increased 72% from $74.6 million for the first three months of 2002 to $128.4 million for the first three months of 2003 as a result of a 65% increase in average realized natural gas prices, from $2.99 per Mcf during the first quarter of 2002 to $4.93 per Mcf in the first quarter of 2003 and an increase in average realized oil prices of 64% for the same period from $19.28 per barrel, or Bbl, to $31.57 per barrel, combined with a 4% increase in production during the current quarter.

Natural Gas Prices. As a result of hedging activities during the first quarter of 2003, we realized an average gas price of $4.93 per Mcf, which was 78% of the average unhedged natural gas price of $6.36 for the period. As a result, natural gas and oil revenues for the three months ended March 31, 2003 that were $34.7 million lower than the revenues we would have achieved if hedges had not been in place during the period. For the corresponding quarter of 2002, we realized an average gas price of $2.99 per Mcf, which was 131% of the average unhedged natural gas price of $2.28 for the period. This resulted in natural gas and oil revenues that were $17.0 million higher than the revenues we would have achieved if hedges had not been in place during the period.

Oil Prices. During the first quarter of 2003, we realized an average oil price of $31.57 per Bbl, which was 94.5% of the average unhedged price of $33.42 per Bbl for the period. As a result, natural gas and oil revenues for the three months ended March 31, 2003 were $0.5 million lower than the revenues we would have achieved if hedges had not been in place during the period. We had no oil hedges in place during first quarter of 2002 and realized an average oil price of $19.28 per Bbl.

Lease Operating Expenses and Severance Tax. Lease operating expenses increased 57% from $7.4 million for the three months ended March 31, 2002 to $11.6 million for the corresponding three months of 2003. On an Mcfe basis, lease operating expenses increased 50% from $0.30 per Mcfe during the first quarter of 2002 to $0.45 per Mcfe during the first quarter of 2003. The increase in both lease operating expenses and lease operating expense on a per unit basis for 2003 is attributable to the continued expansion of our operations both onshore and offshore combined with a slight increase in well-service costs. Onshore, our operating costs were higher as we incurred $1.6 million in non-recurring expenses associated with a workover in the Charco Field together with increases in ad valorem taxes and well control insurance. Offshore, our operating costs were higher due to 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 contract labor costs.

Severance tax, which is a function of volume and revenues generated from onshore production, increased from $1.7 million for the first three months of 2002 to $4.3 million for the corresponding period of 2003. On an Mcfe basis, severance tax increased from $0.07 per Mcfe for the first quarter of 2002 to $0.17 per Mcfe during the first quarter of 2003. Despite our reduced severance tax rate for a portion of our South Texas production pursuant to the "high-cost/tight-gas formation" designation received in July 2002 (see "Other (Income) and Expense" below), severance tax expense and severance tax per Mcfe increased during the first three months of 2003 due to the significant increase in average wellhead prices for natural gas from $2.28 during the first quarter of 2002 to $6.36 during the first quarter of 2003 combined with a 22% increase in onshore production for the first quarter of 2003.

Transportation Expense. We applied 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 for the three months ended March 31, 2002 that were 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. The application of EITF No. 00-10 had no effect on operating income or net income. Transportation expense for the first three months of 2003 increased 11% on an Mcfe basis from $0.09 during the first three months of 2002 to $0.10 for the first three months of 2003. The increase reflects an increase in production for the corresponding period.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased 15% from $39.8 million for the three months ended March 31, 2002 to $45.7 million for the three months ended March 31, 2003. Depreciation, depletion and amortization expense per Mcfe increased 10% from $1.60 for the three months ended March 31, 2002 to $1.76 for the corresponding three months in 2003. 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 as the costs associated with several unproved properties designated as unevaluated were reclassified into our amortization base without incremental reserve additions. In addition, our future development costs increased approximately 22% from prior year estimates due to the addition of more proved undeveloped reserves into our total proved reserve base.

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Asset Retirement Accretion. Pursuant to our January 1, 2003 adoption of SFAS No. 143, "Asset Retirement Obligations," we incurred asset retirement accretion expense of $0.8 million, $0.03 per Mcfe, for the first three months of 2003. The accretion expense represents the systematic, monthly accretion and depreciation of future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and other facilities.

General and Administrative Expenses, Net of Capitalized General and Administrative and Overhead Reimbursements. Our net general and administrative expenses increased 18% from $3.3 million for the three months ended March 31, 2002 to $3.9 million for the three months ended March 31, 2003. These amounts are net of overhead reimbursements received from other working interest owners of $0.6 million and $0.4 million for the three months ended March 31, 2002 and

2003, respectively, and capitalized general and administrative expenses of $3.3 million and $3.7 million for the respective periods. Aggregate general and administrative expenses increased by $0.8 million or 11% from $7.2 million for the first quarter of 2002 to $8.0 million for the first quarter of 2003. However, included in aggregate expense for the first quarter of 2002 was approximately $0.9 million in non-recurring charges relating to employee severance payments. Without these non-recurring charges, aggregate general and administrative expense for the first quarter of 2003 would reflect a $0.8 million or 27% increase from the first quarter of 2002 and net general and administrative expenses for the first quarter of 2003 would reflect a $1.5 million or 63% increase. The increase in aggregate general and administrative expense is due primarily to the expansion of our workforce which corresponds to the continued expansion of our operations. As our workforce expands, we have experienced an increase in salaries and related employee benefit expenses together with an increase in our incentive compensation expense.

On an Mcfe basis, net general and administrative expenses increased 15% from $0.13 during the first quarter of 2002 to $0.15 per Mcfe during the first quarter of 2003. Without the non-recurring charges of $0.9 million incurred in the first quarter of 2002 for employee severance payments, net general and administrative expense per Mcfe would have increased by $0.05 per Mcfe or by 50% from $0.10 in first quarter 2002 to $0.15 in the first quarter of 2003. The higher rate per Mcfe during the first quarter of 2003 reflects the increase in our aggregate general and administrative expenses offset in part by an increase in capitalized expenses during the first quarter of 2003 which is a result of the expansion of our geological and geophysical workforce.

Other Income and Expense. During the first quarter of 2003, we recorded refunds of prior years' severance tax expense totaling $10.6 million ($6.9 million net of tax). 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. The "high-cost/tight-gas formation" designation allows 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. As of the date of our report, we are estimating that we could receive refunds of up to an additional $3.5 million ($2.3 million net of tax), although there can be no assurances that actual amounts collected will equal our estimates.

Interest Expense, Net of Capitalized Interest. Interest expense, net of capitalized interest, increased 64% from $1.4 million for the first three months of 2002 to $2.3 million for the first three months of 2003. Aggregate interest expense was unchanged at $3.6 million during both the first quarter of 2002 and the corresponding period of 2003. Our average borrowings and interest rates were $254.9 million and 5.36% during the first quarter of 2002 compared to $250.1 million and 5.44% during the first quarter of 2003. The increase in net interest expense for the current quarter is due to the decrease in capitalized interest. Capitalized interest decreased 41% from $2.2 million for the first quarter of 2002 to $1.3 million for the first quarter of 2003 and is a result of a decrease in our unevaluated property balance during the first quarter of 2003. Our capitalized interest, which is a function of unevaluated properties, decreased during the quarter corresponding to a decrease in our unevaluated property balance as several properties previously designated as unevaluated were reclassified to the amortization base or full cost pool.

Income Tax Provision. The provision for income taxes increased 275% from $6.4 million for the first three months of 2002 to $24.0 million for the first three months of 2003 due to the 261% increase in pre-tax income during the first quarter of 2003 from $19.0 million during the first quarter of 2002 to $68.5 million during the first quarter of 2003. Pre-tax income is higher as a result of the 72% increase in revenues and the $10.6 million in other income received from refunds of prior years severance tax payments both of which were offset only in part by a 26% increase in operating expenses and a 64% increase in net interest expense.

Operating Income and Income before Cumulative Effect of Change in Accounting Principle. For the three months ended March 31, 2003, the 65% increase in realized natural gas prices combined with the 4% increase in production, offset in part by a 26% increase in operating expenses, caused operating income to increase 195% from $20.4 million during the first quarter of 2002 to $60.2 million during the first quarter of 2003. Correspondingly, income before the cumulative effect of the change in accounting principle increased 256% from $12.5 million for the first quarter of 2002 to $44.5 million for the first quarter of 2003.

LIQUIDITY AND CAPITAL RESOURCES

We currently fund our operations, including capital expenditures and working capital requirements, from cash flows from operations 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 March 31, 2003, we had working capital of $8.6 million and $154.5 million of borrowing capacity available under our revolving bank credit facility. Net cash provided by operating activities for the first three months of 2003 was $63.0 million compared to $33.4 million during the first three months of 2002. The increase in net cash provided by operating activities was due to an increase in net income caused primarily by higher realized natural gas prices and an increase in production volumes for the first quarter of 2003 offset in part by a net decrease in current assets and current liabilities which is related to the timing of cash receipts and payments. For the first quarter of 2003, the decrease in current assets was caused primarily by an increase in receivables for natural gas revenues due to comparatively higher gas prices and production volumes. 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 first quarter of 2003 as compared to the corresponding quarter of 2002. For the first three months of 2003, funds used in investing activities consisted of $53.6 million for net cash investments in property and equipment, which compares to $47.5 million spent during the first quarter of 2002. Our cash position decreased during the first quarter of 2003 as a result of net repayments of borrowings under our revolving bank credit facility of $22 million compared to net borrowings of $5 million during the corresponding quarter of 2002. Cash increased by $0.2 million and $0.6 million, respectively, during the first three months of 2003 and 2002 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 decreased $12.4 million from $18.0 million at December 31, 2002 to $5.6 million at March 31, 2003.

Investments in Property and Equipment. During the first three months of 2003, we invested $53.4 million in natural gas and oil properties and $0.2 million for other property and office equipment. During the first quarter of 2003, we completed the drilling of 26 gross wells (20.9 net) of which 18 (15.4 net) were successful and 8 (5.5 net) were unsuccessful with an additional 14 wells (12.2 net) in progress at the end to the quarter. Our investments in natural gas and oil properties included $11.8 million in exploration costs, $33.6 million in development costs and $8.0 in leasehold acquisition costs. Leasehold acquisition costs include among other things, costs incurred for seismic, capitalized interest and capitalized general and administrative costs. During the first quarters of 2003 and 2002, we capitalized a total of $5.1 million and $5.5 million, respectively, in interest and general and administrative expenses.

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. We have estimated our current asset retirement obligations to be $4.4 million. 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 both offshore and onshore although we may not be able to identify and make acquisitions of proved reserves on terms we consider favorable.

Revolving Bank Credit Facility. We maintain a revolving bank credit facility with a syndicate of lenders led by Wachovia Bank, National Association, as issuing bank and administrative agent, The Bank of Nova Scotia and Fleet National Bank as co-syndication agents and BNP Paribas as documentation agent. The credit facility provides us with a commitment of $300 million which may be increased at our request and with prior approval from Wachovia to a maximum of $350 million by adding one or more lenders or by allowing one or more lenders to increase their commitments. The

credit facility is subject to borrowing base limitations. Our current borrowing base is $300 million and is redetermined semi-annually, with the next redetermination scheduled for October 1, 2003. Up to $25 million of the borrowing base is available for the issuance of letters of credit. The credit facility matures July 15, 2005, is unsecured and with the exception of trade payables, ranks senior to all of our existing debt.

At March 31, 2003, outstanding borrowings under our revolving bank credit facility were $130 million together with $15.5 million in outstanding letter of credit obligations. A $15.1 million letter of credit was issued to a counter party to cover a margin call pursuant to a natural gas hedge contract. Subsequent to March 31, 2003, we repaid a net $35 million under the facility and reduced our letter of credit obligations to $9.4 million. Currently, outstanding borrowings and letter of credit obligations under our revolving bank credit facility total $104.4 million.

Senior Subordinated Notes. On March 2, 1998, we issued $100 million of 8 5/8 Senior Subordinated Notes due January 1, 2008. The notes bear interest at a rate of 8 5/8 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 March 31, 2003. We have no "off-balance sheet" financing arrangements.

	AT MARCH 31, 2003 PAYMENTS DUE BY PERIOD		
CONTRACTUAL OBLIGATIONS	1 - 3 YEARS	4 - 5 YEARS	AFTER 5 YEARS
		($ IN THOUSANDS)	
Revolving bank credit facility	$ 130,000	$ --	$ --
8 5/8 senior subordinated notes	--	--	100,000
Operating leases	3,097	2,331	2,111
Section 29 tax credit repurchase ...	2,000	--	--
Total contractual obligations	$ 135,097	$ 2,331	$ 102,111

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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.

CHANGES IN FAIR VALUE OF DERIVATIVE INSTRUMENTS

The following table summarizes the change in the fair value of our derivative instruments for the three month period from January 1 to March 31, 2003 and 2002, respectively. Stated amounts do not reflect the effects of taxes.

CHANGE IN FAIR VALUE OF DERIVATIVES INSTRUMENTS	2003	2002
	(IN THOUSANDS)	
Fair value of contracts at January 1	$(38,772)	$ 53,771
(Gain) loss on contracts realized	35,194	(16,966)
Fair value of new contracts when entered into during period	--	--
Decrease in fair value of all open contracts	(52,998)	(34,676)
Fair value of contracts outstanding at March 31	$(56,576)	$ 2,129

DERIVATIVES IN PLACE AS OF THE DATE OF OUR REPORT

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 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 which is approximately 67% of our estimated future production for the period. For each month during 2004, we have 100,000 MMBtu/day hedged at a floor of $3.750 and a ceiling of $5.045 which is approximately 38% of our estimated future production for the period.

	FIXED PRICE SWAPS		COLLARS		
PERIOD	VOLUME (MMBTU)	NYMEX CONTRACT PRICE	VOLUME (MMBTU)	NYMEX CONTRACT PRICE AVG FLOOR	AVG CEILING
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

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.

Oil. We entered into an oil swap as described in the following table. All amounts are in thousands, except for prices.

	FIXED PRICE SWAPS		COLLARS		
		NYMEX		NYMEX	
	VOLUME	CONTRACT	VOLUME	CONTRACT PRICE	
PERIOD	(MBBL)	PRICE	(MBBL)	AVG FLOOR	AVG CEILING
April 2003	30	29.70	--	--	--
May 2003	31	29.70	--	--	--
June 2003	30	29.70	--	--	--

With respect to any particular swap transaction, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price for the transaction, and we are required to make payment to the counterparty if the settlement price for any settlement period is greater than the swap price for the transaction. For any particular collar transaction, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price for the transaction, and we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price for the transaction. We are not required to make or receive any payment in connection with a collar transaction if the settlement price is between the floor and the ceiling. For option contracts, we have the option, but not the obligation, to buy contracts at the strike price up to the day before the last trading day for that NYMEX contract.

ITEM 4. 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. Within the 90 days prior to the date of this report, we carried out an evaluation, under the supervision and 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). 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 significant changes in our internal controls or in other factors that could significantly affect these controls subsequent to the date of their evaluation, including any corrective actions with regard to significant deficiencies or material weaknesses.

PART II. OTHER INFORMATION

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K:

(a) Exhibits:

EXHIBITS		DESCRIPTION
*99.1	--	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 906 of The Sarbanes-Oxley Act of 2002.
*99.2	--	Certification of John H. Karnes, Chief Financial Officer, as required pursuant to Section 906 of The Sarbanes-Oxley Act of 2002.

* Filed herewith.

(b) Reports on Form 8-K:

Current Report on Form 8-K filed on February 21, 2003 to provide information in Item 5. - Other Events regarding a press release issued on February 21, 2003 announcing the offering by Houston Exploration of 3,000,000 shares of common stock in an underwritten public offering and concurrent repurchase of a like number of shares from KeySpan.

Current Report on Form 8-K filed February 26, 2003 to provide information in Item 5. - Other Events regarding the Underwriting Agreement between Houston Exploration and J.P. Morgan Securities, Inc. dated February 20, 2003 for the issuance and sale of 3,000,000 shares to the public and the Stock Purchase Agreement among Houston Exploration, KeySpan Corporation and THEC Holdings Corp. dated as of February 20, 2003 and in Item 7. - Financial Statements and Exhibits regarding the Underwriting Agreement and the Stock Purchase Agreement.

Current Report on Form 8-K filed on May 2, 2003 required by Item 12 and filed under Item 9 - Regulation FD Disclosure of our earnings release for the first quarter of 2003.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, hereunto duly authorized.

THE HOUSTON EXPLORATION COMPANY

By: /s/ William G. Hargett

Date: May 5, 2003

William G. Hargett
President and Chief Executive Officer

By: /s/ John H. Karnes

Date: May 5, 2003

John H. Karnes
Senior Vice President, Chief Financial Officer

CERTIFICATIONS

I, William G. Hargett, certify that:

1. I have reviewed this quarterly report on Form 10-Q of The Houston Exploration Company;

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

   (a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

   (b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

   (c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the

equivalent function):

(a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: May 5, 2003

/s/ William G. Hargett

William G. Hargett
President and Chief Executive Officer

CERTIFICATIONS

I, John H. Karnes, certify that:

1. I have reviewed this quarterly report on Form 10-Q of The Houston Exploration Company;

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

(a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

(b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

(c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   (a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: May 5, 2003

/s/ John H. Karnes

John H. Karnes
Senior Vice President and Chief Financial Officer

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EXHIBIT INDEX

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