HOUSTON EXPLORATION CO
Form 10-Q
May 07, 2004

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

**FORM 10-Q**

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

**For the quarterly period ended March 31, 2004**

**OR**

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

**For the transition period from _________to _________**

**Commission File No. 001-11899**

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

| | |
|---|---|
| **Delaware** | **22-2674487** |
| **(State or other jurisdiction of incorporation or organization)** | **(IRS Employer Identification No.)** |

**1100 Louisiana 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 þ No o

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 þ No o

As of May 6, 2004, 31,883,703 shares of Common Stock, par value $.01 per share, were outstanding.

**THE HOUSTON EXPLORATION COMPANY**

**TABLE OF CONTENTS**

Table of Contents

## 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,as amended and Section 21E of the Securities Exchange Act of 1934, as amended. These forward-looking statements generally can be identified by words such as anticipate, believe, expect, continue, 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 future production, expected costs and expenses, anticipated capital expenditures, future cash flows and borrowings, pursuit of potential future acquisition opportunities and sources of funding and the timing of 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 can not guarantee that the anticipated future results will be realized.*

*A number of factors could cause our actual future results to differ materially from those anticipated or implied in the forward-looking statements. These factors include, among other things:*

- *the volatility of natural gas and oil prices;*
- *the requirement to take writedowns if natural gas and oil prices decline or if our finding and development costs continue to increase;*
- *our ability to find, develop and acquire natural gas and oil reserves;*
- *the successfulness of our acquisition and investment activities;*
- *our ability to meet our substantial capital requirements;*
- *our outstanding indebtedness may restrict our financial flexibility;*
- *the uncertainty of estimates of natural gas and oil reserves and production rates;*
- *the inherent hazards and risks involved in our operations;*
- *the concentrated nature of our operations;*
- *our hedging activities could result in financial losses or reductions to income;*
- *our compliance with environmental and other governmental regulations;*
- *the competitive nature of our industry;*
- *our customers ability to meet their obligations; and*
- *potential conflicts with our majority stockholder, KeySpan Corporation.*

*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. We undertake no obligation to publicly update or revise any forward-looking statements.*

*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.*

Table of Contents

**Part I. Financial Information**

**Item 1. Consolidated Financial Statements (unaudited)**

**THE HOUSTON EXPLORATION COMPANY**

**CONSOLIDATED BALANCE SHEETS**
**(in thousands, except share data)**

| | March 31, 2004 | December 31, 2003 |
|---|---|---|
| **Assets:** | | |
| Cash and cash equivalents | $ 13,720 | $ 2,569 |
| Accounts receivable | 95,368 | 87,949 |
| Accounts receivable Affiliate | 6,239 | 6,733 |
| Derivative financial instruments | | 3,458 |
| Inventories | 1,164 | 1,071 |
| Deferred tax asset | 24,011 | 19,644 |
| Prepayments and other | 5,206 | 5,818 |
| Total current assets | 145,708 | 127,242 |
| Natural gas and oil properties, full cost method | | |
| Unevaluated properties | 130,168 | 134,491 |
| Properties subject to amortization | 2,397,315 | 2,324,011 |
| Other property and equipment | 13,219 | 12,617 |
| | 2,540,702 | 2,471,119 |
| Less: Accumulated depreciation, depletion and amortization | 1,160,974 | 1,099,990 |
| | 1,379,728 | 1,371,129 |
| Other non-current assets | 13,664 | 10,694 |
| **Total Assets** | $ 1,539,100 | $ 1,509,065 |
| **Liabilities:** | | |
| Accounts payable and accrued expenses | $ 96,788 | $ 83,983 |
| Derivative financial instruments | 63,535 | 35,592 |
| Asset retirement obligation | 3,642 | 7,703 |
| Total current liabilities | 163,965 | 127,278 |
| Long-term debt and notes | 245,000 | 302,000 |

| | | |
|---|---|---|
| Derivative financial instruments | 20,302 | 4,728 |
| Deferred federal income taxes | 253,938 | 251,425 |
| Asset retirement obligation | 84,930 | 84,654 |
| Other deferred liabilities | 10,173 | 3,446 |
| **Total Liabilities** | 778,308 | 773,531 |
| **Commitments and Contingencies (see Note 3)** | | |
| **Stockholders Equity:** | | |
| Common Stock, $.01 par value, 50,000,000 shares authorized and 31,854,155 shares issued and outstanding at March 31, 2004 and 31,437,581 shares issued and outstanding at December 31, 2003, respectively | 319 | 315 |
| Additional paid-in capital | 380,392 | 366,781 |
| Unearned compensation | (746) | (808) |
| Retained earnings | 435,064 | 395,374 |
| Accumulated other comprehensive income | (54,237) | (26,128) |
| **Total Stockholders Equity** | 760,792 | 735,534 |
| **Total Liabilities and Stockholders Equity** | $1,539,100 | $1,509,065 |

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

Table of Contents

**THE HOUSTON EXPLORATION COMPANY**

**CONSOLIDATED STATEMENTS OF OPERATIONS**
**(in thousands, except per share data)**

| | Three Months Ended March 31, 2004 | Three Months Ended March 31, 2003 |
|---|---|---|
| | (unaudited) | |
| **Revenues:** | | |
| Natural gas and oil revenues | $151,634 | $128,398 |
| Other | 248 | 605 |
| Total revenues | 151,882 | 129,003 |
| **Operating expenses:** | | |
| Lease operating | 12,706 | 11,646 |
| Severance tax | 3,057 | 4,305 |
| Transportation expense | 2,736 | 2,492 |
| Asset retirement accretion expense | 1,288 | 826 |
| Depreciation, depletion and amortization | 60,964 | 45,654 |
| General and administrative, net | 6,088 | 3,884 |
| Total operating expenses | 86,839 | 68,807 |
| Income from operations | 65,043 | 60,196 |
| Other (income) expense | 110 | (10,578) |
| Interest expense, net | 2,287 | 2,266 |
| Income before income taxes | 62,646 | 68,508 |
| Provision for taxes | 22,956 | 24,039 |
| **Income before cumulative effect of change in accounting principle** | $ 39,690 | $ 44,469 |
| Cumulative effect of change in accounting principle. | | (2,772) |
| **Net income** | $ 39,690 | $ 41,697 |
| **Earnings per share:** | | |
| **Net income per share basic** | | |
| Income before cumulative effect of change in accounting principle | $ 1.26 | $ 1.44 |
| Cumulative effect of change in accounting principle | | (0.09) |

| | | |
|---|---|---|
| Net income per share basic | $ 1.26 | $ 1.35 |
| **Net income per share fully diluted** | | |
| Income before cumulative effect of change in accounting principle | $ 1.25 | $ 1.43 |
| Cumulative effect of change in accounting principle | | (0.09) |
| Net income per share fully diluted | $ 1.25 | $ 1.34 |
| Weighted average shares outstanding basic | 31,598 | 30,960 |
| Weighted average shares outstanding fully diluted | 31,714 | 31,069 |

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

Table of Contents

**THE HOUSTON EXPLORATION COMPANY**

**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(in thousands)**

| | Three Months Ended March 31, | |
|---|---|---|
| | **2004** | **2003** |
| | **(unaudited)** | |
| **Operating Activities:** | | |
| Net income | $ 39,690 | $ 41,697 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation, depletion and amortization | 60,964 | 45,654 |
| Deferred income tax expense | 14,814 | 23,981 |
| Asset retirement accretion expense | 1,288 | 826 |
| Ineffectiveness of derivative instruments | 1,000 | |
| Amortization of premium on derivative instruments | 2,730 | |
| Stock compensation expense | 517 | 35 |
| Cumulative effect of change in accounting principle | | 2,772 |
| Changes in operating assets and liabilities: | | |
| Increase in accounts receivable | (6,925) | (63,374) |
| Increase in inventories | (93) | (184) |
| Decrease in prepayments and other | 612 | 5,513 |
| Increase in other assets | (2,970) | (8,519) |
| Increase in accounts payable and accrued expenses | 12,805 | 13,712 |
| Increase in other liabilities | 6,727 | 868 |
| Net cash provided by operating activities | 131,159 | 62,981 |
| **Investing Activities:** | | |
| Investment in property and equipment | (85,222) | (53,646) |
| Assets retired and abandoned | (2,553) | |
| Proceeds from dispositions | 13,138 | |
| Net cash used in investing activities | (74,637) | (53,646) |
| **Financing Activities:** | | |
| Proceeds from long term borrowings | 20,000 | 18,000 |
| Repayments of long term borrowings | (77,000) | (40,000) |
| Proceeds from issuance of common stock from exercise of stock options | 11,629 | 220 |
| Proceeds from issuance of common stock | | 79,200 |
| Repurchase of common stock | | (79,200) |
| Net cash used in by financing activities | (45,371) | (21,780) |

| | | |
|---|---|---|
| Increase (decrease) in cash and cash equivalents | 11,151 | (12,445) |
| Cash and cash equivalents, beginning of period | 2,569 | 18,031 |
| Cash and cash equivalents, end of period | $ 13,720 | $ 5,586 |
| **Supplemental Information:** | | |
| Cash paid for interest | $ 876 | $ 5,564 |
| Cash paid for income taxes | $ | $ |

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

## THE HOUSTON EXPLORATION COMPANY

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
**(unaudited)**

### NOTE 1 Summary of Organization and Significant Accounting Policies

*Our Business*

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

We were founded in December 1985 and began exploring for natural gas and oil on behalf of KeySpan Corporation. KeySpan, a member of the Standard & Poor s 500 Index, is a diversified energy provider whose principal natural gas distribution and electric generation operations are located in the Northeastern United States. In September 1996 we completed our initial public offering and sold approximately 31% of our shares to the public. As of March 31, 2004, THEC Holdings Corp., an indirect wholly owned subsidiary of KeySpan, owned approximately 55% of the outstanding shares of our common stock or 17.4 million shares. KeySpan has publicly announced that it considers its investment in Houston Exploration a non-core asset and that it continues to review strategic alternatives for its investment in our company including the sale of all or a portion of its investment in our common stock.

*Principles of Consolidation*

The consolidated financial statements include our accounts and the accounts of our wholly owned subsidiary, Seneca Upshur Petroleum Company, which is in the exploration and production business in West Virginia. All significant inter-company balances and transactions have been eliminated.

*Interim Financial Statements*

Our balance sheet at March 31, 2004 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, 2003 is derived from the December 31, 2003 audited financial statements, but does not include all disclosures required by GAAP. The financial statements included herein 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, 2003.

In the opinion of our management, these financial statements reflect all adjustments necessary for a fair statement of the results for the interim periods, on a basis consistent with the annual audited financial statements. All such adjustments are of a normal recurring nature. The results of operations for such interim periods are not necessarily indicative of the results for the full year.

*Use of Estimates*

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. Because there are numerous uncertainties inherent in the estimation process, actual results could differ materially from these estimates.

*Business Segment Information*

The Financial Accounting Standards Board ( FASB ) Statement of Financial Accounting Standards ( SFAS ) 131, Disclosures about Segments of an Enterprise and Related Information establishes standards for reporting information about operating segments. All of our operations involve the exploration, development and production of natural gas and oil

Table of Contents

**THE HOUSTON EXPLORATION COMPANY**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**
**(unaudited)**

and all of our operations are located in the United States. We have a single, company-wide management team that administers all properties as a whole rather than as discrete operating segments. We measure financial performance as a single enterprise and not on an area-by-area basis. Consequently, while we compile and analyze basic operational data by area, we do not prepare separate financial statement information by area and are not, therefore, required to report separate business segment information under SFAS 131.

*Revenue Recognition*

We use the entitlements method of accounting for the recognition of natural gas and oil revenues. Under this method of accounting, income is recorded based on our net revenue interest in production or nominated deliveries. We incur production gas volume imbalances in the ordinary course of business. Net deliveries in excess of entitled amounts are recorded as liabilities, while net under deliveries are reflected as assets. Imbalances are reduced either by subsequent recoupment of over-and under deliveries or by cash settlement, as required by applicable contracts. Production imbalances are marked-to-market at the end of each month using market prices as of the end of the period.

*Net Income Per Share*

Basic earnings per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding during the period. No dilution for any potentially dilutive securities is included. Fully diluted earnings per share is calculated by applying the treasury stock method to adjust the average number of common shares outstanding for the dilutive effect, if any, of the assumed conversion of potentially convertible securities.

| | Three Months Ended March 31, | |
|---|---|---|
| | **2004** | **2003** |
| **Numerator:** | | |
| Income before cumulative effect of change in accounting principle | $39,690 | $44,469 |
| Cumulative effect of change in accounting principle | | (2,772) |
| Net income | $39,690 | $41,697 |
| **Denominator:** | | |
| Weighted average shares outstanding | 31,598 | 30,960 |
| Add dilutive securities: Stock options | 116 | 109 |
| Total weighted average shares outstanding and dilutive securities | 31,714 | 31,069 |

| | | |
|---|---|---|
| **Earnings per share basic**: | | |
| Income before cumulative effect of change in accounting principle | $ 1.26 | $ 1.44 |
| Cumulative effect of change in accounting principle | | (0.09) |
| Net income per share basic | $ 1.26 | $ 1.35 |
| **Earnings per share fully diluted:** | | |
| Income before cumulative effect of change in accounting principle | $ 1.25 | $ 1.43 |
| Cumulative effect of change in accounting principle | | (0.09) |
| Net income per share fully diluted | $ 1.25 | $ 1.34 |

For the three months ended March 31, 2004 and 2003, the calculation of potentially dilutive securities does not include the effect of outstanding stock options to purchase 1,585,960 and 1,903,561 shares, respectively, as the assumed conversion of these shares would have been antidulitive.

**Table of Contents**

**THE HOUSTON EXPLORATION COMPANY**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**
**(unaudited)**

*Comprehensive Income*

The table below summarizes our Comprehensive Income for the three month and nine month periods ended March 31, 2004 and 2003, respectively.

| | Three Months Ended March 31, 2004 | Three Months Ended March 31, 2003 |
|---|---|---|
| | (in thousands) | |
| Net income | $ 39,690 | $ 41,697 |
| Other comprehensive income, net of taxes: | | |
| Unrealized gain (loss) on derivative instruments | (28,759) | (11,572) |
| Comprehensive income | $ 10,931 | $ 30,125 |

*Natural Gas and Oil Properties*

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

full cost pool; plus,

estimates for future development costs; less,

unevaluated properties and their related costs; less,

estimates for salvage.

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

Under full cost accounting rules, total capitalized costs are limited to a ceiling equal to the present value of future net revenues, discounted at 10% per annum, plus the lower of cost or fair value of unproved properties less income tax effects (the ceiling limitation ). We perform a quarterly ceiling test to evaluate whether the net book value of our full cost pool exceeds the ceiling limitation. If capitalized costs (net of accumulated depreciation, depletion and amortization) less related deferred taxes are greater than the discounted future net revenues or ceiling limitation, a writedown or impairment of the full cost pool is required. A writedown of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders equity in the period of occurrence and typically results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a writedown is not reversible at a later date.

The ceiling test is calculated using natural gas and oil prices in effect as of the balance sheet date and adjusted for basis or location differential, held constant over the life of the reserves. We use derivative financial instruments that qualify for cash flow hedge accounting under SFAS 133 to hedge against the volatility of natural gas prices, and in accordance with Securities and Exchange Commission guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation.

*Unevaluated Properties*. The costs associated with unevaluated properties and properties under development are not initially included in the amortization base and relate to unproved leasehold acreage, seismic data, wells and production facilities in-progress and wells pending determination together with interest costs capitalized for these projects. Unevaluated leasehold costs are transferred to the amortization base with the costs of drilling the related well or upon expiration of a lease. Costs of seismic data are allocated to various unproved leaseholds and transferred to the amortization base with the associated leasehold costs on a specific project basis. Costs associated with successful wells in-progress and

**THE HOUSTON EXPLORATION COMPANY**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**
**(unaudited)**

wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. Costs of dry holes are transferred to the amortization base immediately upon determination that the well is unsuccessful. All items included in our unevaluated property balance are assessed on a quarterly basis for possible impairment or reduction in value. We estimate these costs will be evaluated within a four-year period.

*Classification of Intangible Leasehold Costs*

SFAS 141, Business Combinations and SFAS 142, Goodwill and Intangible Assets, became effective on July 1, 2001 and January 1, 2002, respectively. These new standards emphasize a more precise evaluation of assets and their balance sheet classification as either tangible or intangible assets. We understand that the issue is under evaluation as to whether provisions of SFAS 141 and SFAS 142 may call for mineral rights held under lease or other contractual arrangements together with cash costs for the acquisition of natural gas and oil leasehold interests to be classified in the balance sheet as intangible assets. If these types of leasehold costs (both proved and unevaluated) are determined to be intangible assets, they would be classified separately from natural gas and oil properties as intangible assets on our balance sheets. This issue relates only to balance sheet classification and presentation and we do not believe it will not have an effect on cash flows or results of operations. At March 31, 2004, if we applied the interpretation currently under discussion, undeveloped leasehold costs of $125.4 million and developed leasehold costs of $207.1 million, net of accumulated amortization, would be reclassified from tangibles to intangibles, representing costs incurred since June 30, 2001, the effective date of SFAS 141. At December 31, 2003, we had undeveloped leasehold costs of $117.1 million and developed leasehold costs of $221.3 million, net of accumulated amortization, that would be reclassified from tangibles to intangibles. Consistent with current industry practice, we will continue to classify our natural gas and oil leasehold costs as tangible natural gas and oil properties until the Emerging Issues Task Force ( EITF ) issues further guidance.

Although the EITF has not issued formal guidance to oil and gas companies, at the March 2004 meeting, the EITF reached a consensus that mineral rights for mining companies should be accounted for as tangible assets. However, the effective date of that consensus is pending until the resolution of a perceived inconsistency between the characterization of mineral rights as tangible assets in this consensus and the characterization of mineral rights as intangible assets in SFAS 141 and SFAS 142. In order to resolve this inconsistency, FASB plans to prepare a FASB Staff Position (FSP) that will amend SFAS 141 and SFAS 142. The consensus will be effective when the FSP has been finalized.

*Asset Retirement Obligations*

On January 1, 2003, we adopted SFAS 143, Accounting for Asset Retirement Obligations, which addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. For us, asset retirement obligations represent the systematic, monthly accretion and depreciation of future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and other facilities. SFAS 143 requires that the fair value of a liability for an asset s retirement obligation be recorded in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the corresponding cost is capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized and an adjustment is made to the full cost pool. Under our previous accounting method, we included estimated future costs of abandonment and dismantlement in our full cost amortization base and amortized these costs as a component of our depletion expense.

Table of Contents

**THE HOUSTON EXPLORATION COMPANY**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**
**(unaudited)**

The following table describes the various components of our asset retirement liability during each of the three month periods ending March 31, 2004 and 2003, respectively. ARO liability includes amounts classified as both current and long-term.

| | Three Months Ended March 31, 2004 | Three Months Ended March 31, 2003 |
|---|---|---|
| ARO liability at January 1, | $ 92,357 | $ 57,197 |
| Additions from drilling | 1,812 | 2,377 |
| ARO accretion expense | 1,288 | 826 |
| Assets sold | (2,928) | |
| Assets retired and abandoned | (3,957) | |
| ARO liability at March 31, | $ 88,572 | $ 60,400 |

*Derivative Instruments and Hedging Activities*

To reduce our exposure to adverse price fluctuations, we plan to hedge between 70 and 80 percent of our estimated future production volume for 2004 and 2005. Our hedging policy does not permit us to hold derivative instruments for trading purposes. In our hedging program, we utilize a variety of derivative instruments, including swaps, collars and options. We generally place contracts with major financial institutions and other credit worthy counterparties. Although our hedging program protects a portion of our cash flows from downward price movements, certain hedging strategies, specifically the use of swaps and collars, may also limit our ability to realize the full benefit of future price increases. In addition, because our derivative instruments are typically indexed to New York Mercantile Exchange ( NYMEX ) prices as opposed to the index price where the gas is actually sold, our hedging strategy may not protect our cash flows if the price differential increases between the NYMEX price and index price for the point of sale.

Our derivative instruments are designated cash flow hedges and qualify for hedge accounting under SFAS 133, as amended, Accounting for Derivative Instruments and Hedging Activities and, accordingly, we carry the fair market value of our derivative instruments on the balance sheet as either an asset or liability and defer unrealized gains or losses in accumulated other comprehensive income. Gains and losses are reclassified from accumulated other comprehensive income to the income statement as a component of natural gas and oil revenues in the period the hedged production occurs. If any ineffectiveness occurs, amounts are recorded directly to the income statement. For the first three months of 2004, our net income includes an unrealized loss of $1.0 million ($0.7 million net of tax) representing the ineffective portion of our derivative instruments that were not eligible for deferral. The ineffectiveness was a result of changes at the end of current period in the price differentials between the index price of the derivative contract, which uses a NYMEX index, and index price for the point of sale for the cash flow that is being hedged, the majority of which is the Houston Ship Channel index.

Based on market prices at March 31, 2004, we recorded an unrealized loss in other comprehensive income of $83.8 million ($54.2 million net of tax). Any loss will be realized in future earnings at the time of the related sales of natural gas production applicable to specific hedges. If prices in effect at March 31, 2004 were to hold, a loss of $63.5 million ($41.3 million net of tax) would be realized over the next 12-month period. However, these amounts could vary materially as a result of changes in market conditions.

*Accounting for Stock Options*

On January 1, 2003, we adopted the fair value expense recognition provisions of SFAS 123, Accounting for Stock Based Compensation, as amended by SFAS 148, Accounting for Stock Based Compensation Transition and Disclosure using the prospective method as defined by the SFAS 148. As a result, we now record as compensation expense the fair value of all stock options issued subsequent to January 1, 2003. No expense has been or will be recorded for grants made in previous years.

For the three months ended March 31, 2004 and 2003, we recognized gross compensation expense of $455,000 and $14,000, respectively, for stock options granted during these periods.

Table of Contents

**THE HOUSTON EXPLORATION COMPANY**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**
**(unaudited)**

Prior to our January 1, 2003 adoption of SFAS 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 123, compensation expense would have had the following pro forma effect on our net income and earnings per share for the three month periods ended March 31, 2004 and 2003. Amounts are in thousands except per share data.

| | Three Months Ended March 31, | |
|---|---|---|
| | **2004** | **2003** |
| Net income as reported | $39,690 | $41,697 |
| Add: Stock-based compensation expense included in net income, net of tax | 230 | 23 |
| Less: Stock-based compensation expense using fair value method, net of tax | (1,267) | (1,086) |
| Net income pro forma | $38,653 | $40,634 |
| Net income per share as reported | $ 1.26 | $ 1.35 |
| Net income per share fully diluted as reported | 1.25 | 1.34 |
| Net income per share pro forma | $ 1.22 | $ 1.31 |
| Net income per share fully diluted pro forma | 1.21 | 1.31 |

**NOTE 2 Long-Term Debt and Notes**

| | March 31, 2004 | December 31, 2003 |
|---|---|---|
| | (in thousands) | |
| **Senior Debt:** | | |
| Revolving bank credit facility, due April 1, 2008 | $ 70,000 | $ 127,000 |
| **Subordinated Debt:** | | |
| 7% senior subordinated notes, due June 15, 2013 | 175,000 | 175,000 |
| Total long-term debt and notes | $245,000 | $ 302,000 |

The carrying amount of borrowings outstanding under the revolving bank credit facility approximates fair value as the interest rates are tied to current market rates. At March 31, 2004, the quoted market value of our $175 million of 7% senior subordinated notes was 97.7% of the $175 million carrying value or $170.9 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 and Comerica Bank as co-documentation agents. The credit facility was amended on April 1, 2004 and, as amended, provides us with a commitment of $400 million which may be increased at our request and with prior approval from Wachovia to a maximum of $450 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. Pursuant to the April 1, 2004 amendment, our borrowing base was increased from $300 million to $375 million. The $375 million borrowing base is expected to remain in effect until the next scheduled redetermination on October 1, 2004. Up to $40 million of the borrowing base is now available for the issuance of letters of credit, which was increased from $25 million pursuant to the April 1, 2004 amendment. Outstanding borrowings continue to be unsecured and with the exception of trade payables, the facility ranks senior in right of payment to our $175 million 7% subordinated notes. The amended facility matures on April 1, 2008. At March 31, 2003, we had $70 million in outstanding borrowings under the credit facility and $0.4 million in outstanding letter of credit obligations.

Interest rates, margins and terms of payment remained unchanged from prior periods pursuant to the April 1, 2004 amendment. Interest is payable on borrowings under our revolving bank credit facility, as follows:

Table of Contents

**THE HOUSTON EXPLORATION COMPANY**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**
**(unaudited)**

on base rate loans, at a fluctuating rate, or base rate, equal to the sum of (a) the greater of the Federal funds rate plus 0.5% or Wachovia s prime rate plus (b) a variable margin between 0% and 0.50%, depending on the amount of borrowings outstanding under the credit facility, or

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

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

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

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

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

not hedge more than 85% of our natural gas production during any 12-month period, which was increased, pursuant to the April 1, 2004 amendment, from 80% during 2003 and 2004, and not more than 70% during any 12-month period after 2004.

At March 31, 2004 and December 31, 2003, we were in compliance with all covenants.

*Senior Subordinated Notes*

On June 10, 2003, we issued $175 million of 7% senior subordinated notes due June 15, 2013. The notes bear interest at a rate of 7% per annum with interest payable semi-annually on June 15 and December 15, beginning December 15, 2003. We may redeem the notes at our option, in whole or in part, at any time on or after June 15, 2008 at a price equal to 100% of the principal amount plus accrued and unpaid interest, if any, plus a specified premium which decreases yearly from 3.5% in 2008 to 0% in 2011 and thereafter. In addition, at any time prior to June 15, 2006, we may redeem up to a maximum of 35% of the aggregate principal amount with the net proceeds of one or more equity offerings at a price equal to 107% of the principal amount, plus accrued and unpaid interest and liquidated damages, if any. The notes are general unsecured obligations and rank subordinate in right of payment to all existing and future senior debt, including the revolving bank credit facility, and will rank senior or equal in right of payment to all existing and future subordinated indebtedness.

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

incurrence of additional indebtedness and issuance of preferred stock;

- repayment of certain other indebtedness;
- payment of dividends or certain other distributions;
- investments and repurchases of equity;
- use of the proceeds of assets sales;
- transactions with affiliates;
- creation, incurrence or assumption of liens;
- merger or consolidation and sales or other dispositions of all or substantially all of our assets;
- entering into agreements that restrict the ability of our subsidiary to make certain distributions or payments; or
- guarantees by our subsidiary of certain indebtedness.

In addition, upon the occurrence of a change of control, we will be required to offer to purchase the notes at a purchase price equal to 101% of the aggregate principal amount, plus accrued and unpaid interest and liquidated damages, if any.

**Table of Contents**

**THE HOUSTON EXPLORATION COMPANY**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**
**(unaudited)**

A change of control is:

- the direct or indirect acquisition by any person, other than KeySpan or its affiliates, of beneficial ownership of 35% or more of total voting power as long as KeySpan and its affiliates own less than the acquiring person;
- the sale, lease, transfer, conveyance or other disposition, other than by way of merger or consolidation, in one or a series of related transactions, of all or substantially all of our assets to a third party other than KeySpan or its affiliates;
- the adoption of a plan relating to our liquidation or dissolution; or
- if, during any period of two consecutive years, individuals who at the beginning of the period constituted our board of directors, including any new directors who were approved by a majority vote of directors then in office who were either directors at the beginning of the two-year period or who were previously so approved, cease for any reason to constitute a majority of the members then in office.

**NOTE 3 Commitments and Contingencies**

*Legal Proceedings*

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

**NOTE 4 Related Party Transactions**

*KeySpan s Investment in Our Company*

KeySpan has publicly announced that it considers its investment in Houston Exploration a non-core asset and that it continues to review strategic alternatives for its investment in our company including the sale of all or a portion of its investment in our common stock. At March 31, 2004, KeySpan held approximately 55% of the common shares outstanding or 17.4 million shares.

*KeySpan Joint Venture*

In January 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.

In December 2000, KeySpan and Houston Exploration agreed to end the primary or exploratory term of the joint venture. As a result, KeySpan has not participated in any of our offshore exploration prospects unless the project involved the development or further exploitation of discoveries made during the initial term of the joint venture.

In October 2002, we purchased from KeySpan a portion of the assets developed under the joint exploration agreement. The acquisition consisted of interests averaging between 11.25% and 45% in 17 wells covering eight of the twelve blocks that were developed under the joint exploration agreement from 1999 through 2002. KeySpan retained a 45% interest in four blocks: South Timbalier 314 and 317 and Mustang Island 725 and 726 as these blocks were in various stages of development at the time of the acquisition. Both Houston Exploration and KeySpan farmed out their interest in Mustang Island 725/726 during 2003, leaving South Timbalier 314 and 317 as the only field in the joint venture.

During the first three months of 2004 KeySpan did not incur any capital expenditures relating to its working interests in properties developed under the joint venture. During the first three months of 2003 KeySpan spent approximately $3.0 million in capital costs for remaining assets.

**Table of Contents**

**THE HOUSTON EXPLORATION COMPANY**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**
**(unaudited)**

## NOTE 5 Acquisitions and Dispositions

*Sale of Onshore South Louisiana Properties*

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

Table of Contents

### Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

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

Statements in our discussion may be forward-looking. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations. See Forward-Looking Statements at the beginning of this Quarterly Report and Risk Factors Affecting Our Business found on page 13 of our Annual Report on Form 10-K for additional discussion of some of these factors and risks.

### Overview of Our Business

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

At December 31, 2003, our net proved reserves were 755 billion cubic feet equivalent or Bcfe, with a present value, discounted at 10% per annum, of cash flows before income taxes of $2.0 billion. Our reserves are fully engineered on an annual basis by independent petroleum engineers. Approximately 94% of our net proved reserves at December 31, 2003 were natural gas, approximately 68% of which were classified as proved developed. We operate approximately 85% of our producing wells.

At March 31, 2004, KeySpan held approximately 55% of our common stock. KeySpan has indicated a desire to divest of its investment in our company. KeySpan has publicly announced it does not consider its investment in Houston Exploration a part of its core asset group and that it may sell or dispose of all or a portion of its non-core assets, including its investment in our company.

### Source of Our Revenues

We derive our revenues from the sale of natural gas and oil that is produced from our natural gas and oil properties. Revenues are a function of the volume produced and the prevailing market price at the time of sale. The price of natural gas is the primary factor affecting our revenues. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we utilize derivative instruments to hedge future sales prices on a significant portion of our natural gas production. The use of certain types of derivative instruments may prevent us from realizing the full benefit of upward price movements.

### Principal Components of Our Cost Structure:

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

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

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

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

Table of Contents

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

*Income Taxes.* We are generally subject to a 35% federal income tax rate. For income tax purposes, we are allowed deductions for accelerated depreciation, depletion and intangible drilling costs that reduce our current tax liability. Prior to 2003, all of our taxes, both federal and state, were deferred; however, during 2003, we utilized all of our net operating loss carryforwards and as a result, we recognized current income tax expense and will continue to recognize current tax expense as long as we are generating taxable income.

**Critical Accounting Estimates**

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

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

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

**Recent Accounting Developments**

SFAS 141, Business Combinations and SFAS 142, Goodwill and Intangible Assets, became effective on July 1, 2001 and January 1, 2002, respectively. These new standards emphasize a more precise evaluation of assets and their balance sheet classification as either tangible or intangible assets. We understand that the issue is under evaluation as to whether provisions of SFAS 141 and SFAS 142 may call for mineral rights held under lease or other contractual arrangements together with cash costs for the acquisition of natural gas and oil leasehold interests to be classified in the balance sheet as intangible assets. If these types of leasehold costs (both proved and unevaluated) are determined to be intangible assets, they would be classified separately from natural gas and oil properties as intangible assets on our balance sheets. This issue relates only to balance sheet classification and presentation and we do not believe it will have an effect on cash flows or results of operations. At March 31, 2004, if we applied the interpretation currently under discussion, undeveloped leasehold costs of $125.4 million and developed leasehold costs of $207.1 million, net of accumulated amortization, would be reclassified from tangibles to intangibles, representing costs incurred since June 30, 2001, the effective date of SFAS 141. At December 31, 2003, we had undeveloped leasehold costs of $117.1 million and developed leasehold costs of $221.3 million, net of accumulated amortization, that would be reclassified from tangibles to intangibles. Consistent with current industry practice, we will continue to classify our natural gas and oil leasehold costs as tangible natural gas and oil properties until the Emerging Issues Task Force issues further guidance.

Although the EITF has not issued formal guidance to oil and gas companies, at the March 2004 meeting, the EITF reached a consensus that mineral rights for mining companies should be accounted for as tangible assets. However, the effective date of that consensus is pending until the resolution of a perceived inconsistency between the characterization of mineral rights as tangible assets in this consensus and the characterization of mineral rights as intangible assets in SFAS 141 and

Table of Contents

SFAS 142. In order to resolve this inconsistency, FASB plans to prepare a FASB Staff Position (FSP) that will amend SFAS 141 and SFAS 142. The consensus will be effective when the FSP has been finalized.

**Overview of First Quarter 2004 Results**

Production growth from Gulf of Mexico properties acquired during the fourth quarter of 2003 together with newly developed production and strong energy commodity prices were the primary factors behind results for operations, earnings and cash flows during the first quarter of 2004. The increase in our cash flows allowed for increased capital spending for drilling and the repayment of debt. During the first quarter of 2004:

We generated $39.7 million in net income, a decrease of 5% from the first quarter of 2003; however, first quarter 2003 net income of $41.7 million includes other income of $10.6 million ($6.9 million after tax) relating to recoupment of prior years severance tax expense pursuant to the receipt of high-cost/tight sand designation for a portion of our South Texas production and a $2.8 million non-cash after-tax charge for the cumulative effect of adopting SFAS 143, Accounting for Asset Retirement Obligations;

We produced a total of 30 Bcfe and increased our average daily production rate by 15% year-over-year to a record 332 MMcfe, and by 6% sequentially from of average of 312 MMcfe per day during the fourth quarter of 2003;

We drilled 50 wells, approximately doubling the number drilled during the first quarter of 2003, with 46 onshore and 4 offshore, of which 43 were successful, including 5 wells in the Uinta Basin, our new focus area;

We successfully integrated our fourth quarter 2003 Gulf of Mexico and West Virginia producing property acquisitions;

We completed the divestiture of our South Louisiana properties, selling 12.3 Bcfe of net proved reserves for a net $13.1 million in February 2004;

We generated $131.2 million in net cash flows from operating activities, invested a net $85.2 million in natural gas and oil properties and paid down a net $57 million in borrowings under our revolving bank credit facility; and

We completed the renegotiation of our revolving bank credit facility, increasing the maximum capacity from $350 million to $450 million, increasing our borrowing base from $300 million to $375 million, and extending the maturity from July 2005 to April 2008. These new terms were effective April 1, 2004.

Table of Contents

| Recent Financial and Operating Results | For the Three Months Ended March 31, 2004 | 2003 | Variance | % change |
|---|---|---|---|---|
| **Summary operating information (in thousands)**: | | | | |
| Operating revenues | $151,882 | $129,003 | $22,879 | 18% |
| Operating expenses | 86,839 | 68,807 | 18,032 | 26% |
| Income from operations | 65,043 | 60,196 | 4,847 | 8% |
| Net income | $ 39,690 | $ 41,697 | $ (2,007) | -5% |
| **Production**: | | | | |
| Natural gas (MMcf) | 28,132 | 24,385 | 3,747 | 15% |
| Oil (MBbls) | 348 | 257 | 91 | 35% |
| Total (MMcfe) (2) | 30,220 | 25,927 | 4,293 | 17% |
| Average daily production (MMcfe/day) | 332 | 288 | 44 | 15% |
| **Average Sales Prices**: | | | | |
| Natural Gas (per Mcf) realized (1) | $ 4.99 | $ 4.93 | $ 0.06 | 1% |
| Natural Gas (per Mcf) unhedged | 5.43 | 6.36 | (0.93) | -15% |
| Oil (per Bbl) realized (1) | 32.50 | 31.57 | 0.93 | 3% |
| Oil (per Bbl) unhedged | 32.50 | 33.42 | (0.92) | -3% |

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

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

**Operating Income**

A 15% increase in average daily production and the narrowing of our losses from hedging activities were the primary factors contributing to our 8% increase in operating income for the first quarter of 2004. The 18% increase in revenues during the current quarter was offset in part by a 26% increase in operating expenses due primarily to the continued expansion of our operations combined with an increase in costs to maintain our existing production base together with higher depreciation, depletion and amortization rates.

**Production Volume**

The 15% increase in average daily production for the current quarter is a result of production added from our acquisition of Gulf of Mexico properties during the fourth quarter of 2003 combined with newly developed production brought online since the end of the first quarter of 2003.

Onshore, our daily production rates increased 7% from an average of 173 MMcfe per day during the first quarter of 2003 to 185 MMcfe per day during the first quarter of 2004. The increase in onshore production is attributable to newly developed production in Arkoma as we continue the accelerated development drilling program initiated in 2003. During 2003, we more than doubled the number of wells drilled in Arkoma by successfully drilling 46 wells and during the first quarter of 2004, we drilled and completed 13 successful wells. The impact of the newly developed production was seen in the fourth quarter of 2003 as our average daily rate in Arkoma increased from 21 MMcfe per day at the beginning of 2003 to 25 MMcfe per day during the fourth quarter and has continued to increase to an average of 33 MMcfe per day during the first quarter of 2004. In South Texas, production has remained flat at 141 MMcfe per day compared to 142 MMcfe per day during the first quarter of 2003. The increase in production of approximately 5 MMcfe/day from the additional West Virginia properties acquired during the fourth quarter of 2003 was offset by the production lost pursuant to the divesture of our South Louisiana properties in February 2004. We expect onshore production to remain at current levels during the second quarter of 2004.

Offshore, our production increased 28% from an average of 115 MMcfe per day during the first quarter of 2003 to an average of 147 MMcfe per day during the first quarter of 2004. The increase is due primarily to the addition of approximately 30 MMcfe per day from the properties acquired mid-October 2003 from Transworld Exploration and

Table of Contents

Production Inc. In addition to the production acquired, we have added approximately 10 MMcfe per day from development wells drilled at High Island A283, one of the fields acquired. Since the end of the first quarter of 2003, we have added approximately 28 MMcfe per day from new fields and wells at: High Island 47, High Island 115, Galveston 389/424, Eugene Island 159 and East Cameron 280. Offsetting production increases were declines from existing and maturing fields totaling 36 MMcfe per day. For the second quarter of 2004, we expect offshore production to remain at current levels.

**Commodity Prices and Effects of Hedging**

Due to the effects of our hedges, our average realized price for natural gas for the first quarter of 2004 was relatively unchanged at $4.99 compared to the $4.93 realized during the first quarter of 2003. However, our average unhedged or wellhead price for natural gas decreased 15% from $6.36 per Mcf during the first quarter of 2003 to $5.43 per Mcf during the first quarter 2004.

Our realized average natural gas price for first quarter 2004 of $4.99 per Mcf was 92% or $0.44 per Mcf lower than our average unhedged natural gas price or wellhead price of $5.43 for the period. Included in natural gas revenues is a loss of $12.5 million from natural gas hedging activities, which includes an unrealized loss of $1.0 million representing the ineffective portion of our derivative instruments that are not eligible for deferral under SFAS 133. For the corresponding three-month period of 2003, our average realized price of $4.93 per Mcf was 78% or $1.43 lower than the average unhedged natural gas price of $6.36 for the period. This resulted in a hedge loss from natural gas derivatives and reduction to natural gas revenues for first quarter 2003 of $34.7 million. In addition, during the first quarter of 2003, we incurred a loss for oil swaps of $0.5 million.

**Natural Gas and Oil Revenues**

The 18% increase in operating revenues was due to the narrowing of our loss from hedging activities from $35.2 million in the first quarter of 2003 to $12.5 million in the first quarter of 2004 as the increase in revenues resulting from the 17% increase in production volume during the current quarter was offset by the decrease in revenues resulting from realized commodity prices remaining relatively unchanged quarter over quarter.

**Operating Expenses**

Our overall operating expenses have increased as we continue to expand our business and operations. Lease operating expenses have increased as we continue to add new wells and production facilities while maintaining production from existing, maturing properties. Our depreciation, depletion and amortization expense continues to increase as our production increases and as we experience higher finding costs as well as higher future development costs. Finally, general and administrative expense continues to increase as we expand our workforce to keep pace with our expanding operations.

| | Three Months Ended March 31, | | | |
|---|---|---|---|---|
| **Operating Expenses per Mcfe:** | **2004** | **2003** | **Variance** | **% change** |
| Lease operating expense | $0.42 | $0.45 | $(0.03) | -7% |
| Severance tax | 0.10 | 0.17 | (0.07) | -41% |
| Transportation expense | 0.09 | 0.10 | (0.01) | -10% |
| Asset retirement accretion expense | 0.04 | 0.03 | 0.01 | 33% |

| | | | | |
|---|---|---|---|---|
| Depreciation, depletion and amortization | 2.02 | 1.76 | 0.26 | 15% |
| General and administrative, net | 0.20 | 0.15 | 0.05 | 33% |
| Total operating expenses per unit of production | $2.87 | $2.66 | $ 0.21 | 8% |

*Lease Operating Expense*. Lease operating expense during the first quarter 2003 includes non-recurring expenses associated with workovers of $1.5 million. Taking into account these non-recurring expenses, first quarter 2003 lease operating expense would have been approximately $0.39 compared to $0.42 for first quarter of 2004. The increase of 8% is due primarily to the acquisition of the offshore properties in mid-October 2003 from Transworld offset in part by a 17% increase in production during the first quarter of 2004. The majority of the Transworld fields were originally developed by major oil and gas producers and due to their age and complexity, we expected that our lease operating expenses would be higher than previous levels. For the second quarter of 2004, we expect lease operating expense to average approximately $0.52 per Mcfe as we are anticipating increases in expenses for workovers scheduled during the second quarter of 2004.

Table of Contents

*Severance Tax*. Severance tax is a function of volume and revenues generated from onshore production. The decrease in severance tax expense and severance tax per Mcfe for the first quarter of 2004 is due primarily to the effects of the reduction in expense from the high-cost/tight-sand designation received for a portion of our South Texas production combined with a 15% decrease in average wellhead prices for natural gas during first quarter of 2004 and an increase in onshore production volumes. We expect severance tax to average approximately $0.12 per Mcfe during the second quarter of 2004.

*Depreciation, Depletion and Amortization*. The increase in our depreciation, depletion and amortization expense for the current quarter was primarily a result of a higher depletion rate combined with a 17% increase in production volumes. The increase in our depletion rate is primarily a result of adding more costs to our depreciation base with fewer reserve additions. For the second quarter of 2004, we expect depreciation, depletion and amortization expense to average approximately $2.03 per Mcfe.

*Asset Retirement Accretion Expense.* The increase in ARO accretion during the first quarter of 2004 is primarily a result of additions to our ARO liability during the fourth quarter of 2003 of approximately $29.2 million from the acquisition of the Gulf of Mexico properties in October and the West Virginia properties in December offset in part by reductions during the first quarter of 2004 of $3.9 million for offshore properties abandoned and $2.9 million for the South Louisiana properties sold in February.

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

| | **Three Months Ended March 31,** | | | |
|---|---|---|---|---|
| **General and Administrative per Mcfe:** | **2004** | **2003** | **Variance** | **% change** |
| Gross general and administrative expense | $ 0.36 | $ 0.31 | $ 0.05 | 16% |
| Operating overhead reimbursements | (0.02) | (0.02) | | |
| Capitalized general and administrative expense | (0.14) | (0.14) | | |
| General and administrative expense, net | $ 0.20 | $ 0.15 | $ 0.05 | 33% |

The increase in aggregate general and administrative expense is primarily due to the expansion of our workforce and our office space. We have experienced an increase in salaries and related employee benefit expenses that include increases in our incentive compensation expense together with expense for stock compensation as we adopted the fair value expense provisions for stock options under SFAS 123, as amended, in January 2003. Our rent expense increased as we expanded our leased office space in downtown Houston to accommodate our growing workforce and opened an office in Denver to coordinate our expansion into the Rocky Mountain region. We expect that as our company continues to grow and expand, our general and administrative expenses will increase. For the second quarter of 2004, we estimate that net general and administrative expenses will average approximately $0.19 per Mcfe.

**Other Income and Expense, Interest and Taxes**

O*ther Income and Expense*. During the first quarter of 2003, Other Income and Expense is comprised of income of $10.6 million ($6.9 million net of tax) related to the recoupment of prior years severance tax expense. In July 2002, we applied for and received from the Railroad Commission of Texas a high-cost/tight-gas formation designation for a portion of our South Texas production. For qualifying wells, production is either exempt from tax or taxed at a reduced rate until certain capital costs are recovered. The recognition of other income as a result of the recoupment of prior years expense were 2003 and fourth quarter 2002 events and for 2004, we do not expect to recognize recoupment of prior years severance tax in excess of $1.0 million. We expect however to see the benefits of the high-cost/tight-gas designation in the form of reduced severance tax expense for a portion of our South Texas production during 2004 and in future periods.

Table of Contents

*Interest Expense, Net of Capitalized Interest.*

| | Three Months Ended March 31, | | | |
|---|---|---|---|---|
| **Interest Expense and Average Borrowings** | **2004** | **2003** | **Variance** | **% change** |
| Gross interest | $ 4,228 | $ 3,637 | $ 591 | 16% |
| Capitalized interest | (1,941) | (1,371) | (570) | 42% |
| Interest expense, net of amounts capitalized | $ 2,287 | $ 2,266 | $ 21 | 1% |
| Average borrowings | $281,400 | $250,100 | $31,300 | 13% |
| Average interest rate | 5.53% | 5.44% | 0.09% | 2% |

During the first quarter of 2004, gross interest increased as our average borrowings increased and our average interest rate increased. In June 2003, we replaced our fixed debt of $100 million at 8-5/8% with new fixed debt of $175 million at 7% and used excess proceeds from the newly issued debt to repay outstanding borrowings under our revolving bank credit facility which bears interest at lower rates that averaged 3.30% during both the first quarter of 2004 and 2003. Capitalized interest is a function of unevaluated properties and the increase corresponds to the increase in our average unevaluated property balance during the first quarter of 2004. The increase in unevaluated property is a result of the October 2003 acquisition of Gulf of Mexico producing properties from Transworld.

*Income Tax Provision.* The 5% decrease in income taxes for the first quarter of 2004 corresponds to the decrease in income before taxes caused by the $10.6 million of other income recognized in the first quarter of 2003 for the recoupment of prior periods severance tax expense. Our current provision increased to $8.1 million as we depleted our net operating loss carryforwards during 2003 and moved to a tax paying status, whereas during the first quarter of 2003, all federal income taxes were deferred.

**Liquidity**

**Capital Requirements**

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

Costs of acquiring and maintaining our lease acreage position and our seismic resources;

Costs of drilling and completing new natural gas and oil wells;

Costs of installing new production infrastructure;

Costs of maintaining, repairing, and enhancing existing natural gas and oil wells;

- Costs related to plugging and abandoning unproductive or uneconomic wells; and
- Indirect costs related to our exploration activities, including payroll and other expense attributable to our exploration professional staff.

Our capital expenditure budget for 2004 has been set at an initial level of $315 million. To maintain flexibility of our capital program, we do not enter into material long-term obligations with any of our drilling contractors or services providers. We do not include property acquisition costs in our capital budget because the size and timing of capital requirements for acquisitions are inherently unpredictable. As the remainder of the year progresses, we will continue to evaluate our capital spending. Actual levels may vary due to a variety of factors, including drilling results, natural gas prices, economic conditions and future acquisitions.

During the first quarter of 2004, we invested $84.6 million in natural gas and oil properties and $0.6 million for other property and equipment. Capital expended for non-natural gas and oil properties includes the improvements to our Houston office space, upgrades to our information technology systems and equipment and purchases of vehicles. During the first quarter of 2004, we spent 28% offshore and 65% onshore with the balance of 7% on capitalized interest and general and administrative costs. We completed the drilling of 50 gross wells (42.3 net) of which 86% or 43 (36.7 net) were successful and 7 (5.6 net) were unsuccessful, with an additional 10 wells (5.3 net) in progress at the end of the quarter. The table below details the components of our natural gas and oil expenditures during each of three month periods ended March 31, 2004 and 2003.

| | Three Months Ended March 31, | |
|---|---|---|
| | 2004 | 2003 |
| | (in thousands) | |
| **Natural gas and oil capital expenditures** | | |
| Producing property acquisitions | $ 2,700 | $ |
| Leasehold and lease acquisition costs(1) | 13,634 | 7,970 |
| Development | 57,536 | 33,617 |
| Exploration | 10,768 | 11,784 |
| Total natural gas and oil capital expenditures | $84,638 | $53,371 |

(1) For the first three months of 2004 and 2003 leasehold costs include capitalized interest and general and administrative expenses of $6.1 million and $5.1 million, respectively.

**Future Commitments**

In addition to our capital expenditure program, we are committed to making cash payments in the future on two types of contracts: note agreements and operating leases. We do not have off-balance sheet debt or other such unrecorded obligations, and we have not guaranteed the debt of any other party. The table below provides estimates of the timing of future payments that we were obligated to make based on agreements in place at March 31, 2004. In addition to the contractual obligations listed on the table below, our balance sheet at March 31, 2004, reflects accrued interest payable on our revolving bank credit facility of approximately $20,000, which is payable over the next 90-day period. We expect to make annual interest payments of $12.5 million per year on our $175 million of 7% senior subordinated notes due June 2013. We anticipate making income tax payments of approximately $30 million to $40 million in 2004.

| | At March 31, 2004 | | | | |
|---|---|---|---|---|---|
| | Payments Due by Period | | | | |
| | Total | 1 year or less | 2 - 3 years | 4 - 5 years | after 5 years |
| | (in thousands) | | | | |
| **Contractual Obligations:** | | | | | |
| Revolving bank credit facility, due April 2008 | $ 70,000 | $ | $ | $70,000 | $ |
| 7% senior subordinated notes, due June 2013 | 175,000 | | | | 175,000 |
| Operating leases | 8,050 | 1,128 | 4,422 | 2,500 | |

| | | | | | |
|---|---|---|---|---|---|
| | 253,050 | 1,128 | 4,422 | 72,500 | 175,000 |
| **Other Long-Term Obligations:** | | | | | |
| Asset retirement obligations | 88,572 | 3,642 | 7,760 | 3,953 | 73,217 |
| **Total contractual obligations and commitments** | $341,622 | $ 4,770 | $12,182 | $76,453 | $248,217 |

Table of Contents

### Capital Resources

We intend to fund our capital expenditure program and contractual commitments through cash flows from our operations and borrowings under our revolving bank credit facility. To the extent we make a significant acquisition, we may also access public markets for debt. Our primary sources of cash during the first three months of 2004 were from funds generated from operations. Cash was used to fund exploration and development expenditures and to reduce debt under our revolving bank credit facility. We made aggregate cash payments of $0.9 million interest and no cash payments for taxes. The table below summarizes the sources of cash during each of the three month periods ended March 31, 2004 and 2003.

| | Three Months Ended March 31, | | | |
|---|---|---|---|---|
| | 2004 | 2003 | variance | % change |
| | (in thousands) | | | |
| Net income | $ 39,690 | $ 41,697 | $ (2,007) | -5% |
| Non-cash charges | 81,313 | 73,268 | 8,045 | 11% |
| Cash from operations before changes in operating assets and liabilities | 121,003 | 114,965 | 6,038 | 5% |
| Decrease (increase) in operating assets and liabilities | 10,156 | (51,984) | 62,140 | -120% |
| Net cash provided by operating activities | 131,159 | 62,981 | 68,178 | 108% |
| Net cash used for investments in property and equipment | 74,637 | 53,646 | 20,991 | 39% |
| Net cash used in financing activities | 45,371 | 21,780 | 23,591 | 108% |
| Net increase (decrease) in cash | $ 11,151 | $ (12,445) | $23,596 | -190% |

At March 31, 2004, we had a working capital deficit of $18.3 million, long-term debt of $245 million and $229.6 million of borrowing capacity available under our revolving bank credit facility. The working capital deficit was due to a current liability of $63.5 million representing the fair value of our derivative instruments. The fair value of our derivative instruments will fluctuate with commodity prices, and as commodity prices increase, our liquidity exposure tends to increase as a result of open derivative instruments. Consequently, we are more likely to have the largest unfavorable mark-to-market position in a high commodity price environment. Our working capital balance fluctuates as a result of the timing and amount of cash receipts and disbursements for operating activities and borrowings or repayments under our revolving bank credit facility. As a result, we often have a working capital deficit or a relatively small amount of positive working capital.

The increase in net cash provided by operating activities during the first quarter of 2004 was attributable to the increase in operating income primarily as a result of the 15% increase in average daily production combined with changes in operating assets and liabilities. Fluctuations in operating assets and liabilities are caused by the timing of cash receipts and disbursements. The net increase in operating assets and liabilities and resulting decrease to cash flows during the first quarter of 2003 was due primarily to the increase in receivables during the prior period caused by higher commodity prices.

*Access to Capital Markets*. In March 2004, we filed a shelf registration statement with the SEC for an initial aggregate public offering price of up to $600 million covering the sale, from time to time, of our common stock, preferred stock, depositary shares and debt securities, or a combination of any of these securities. In addition, the shelf filed in March 2004 registered the 17.4 million shares of our common stock held by KeySpan.

We believe that operating cash flow and our credit facility will be adequate to meet our capital and operating requirements for the remaining portion of 2004. We continuously monitor our working capital and debt position as well as coordinate our capital expenditure program with expected cash flows and projected debt repayment schedules. Although we have no specific budget for property acquisitions, should attractive opportunities arise, we believe we could finance the additional capital expenditures with cash on hand, operating cash flow, additional borrowing under our revolving bank credit facility, issuances of additional equity or debt securities or development with industry partners.

Table of Contents

## Item 3. Quantitative and Qualitative Disclosures About Market Risk

### Natural Gas and Oil Hedging

We utilize derivative commodity instruments to hedge future sales prices on a portion of our natural gas and oil production to achieve a more predictable cash flow, as well as to reduce our exposure to adverse price fluctuations of natural gas. Our derivatives are not held for trading purposes. While the use of hedging arrangements limits the downside risk of adverse price movements, it also limits increases in future revenues as a result of favorable price movements. The use of hedging transactions also involves the risk that the counterparties are unable to meet the financial terms of such transactions. Hedging instruments that we use are swaps, collars and options, which we generally place with major investment grade financial institutions that we believe are minimal credit risks. We believe that our credit risk related to our natural gas futures and swap contracts is no greater than the risk associated with the primary contracts and that the elimination of price risk reduces volatility in our reported results of operations, financial position and cash flows from period to period and lowers our overall business risk; however, as a result of our hedging activities we may be exposed to greater credit risk in the future.

Our hedges are cash flow hedges and qualify for hedge accounting under SFAS 133 and, accordingly, we carry the fair market value of our derivative instruments on the balance sheet as either an asset or liability and defer unrealized gains or losses in accumulated other comprehensive income. Gains and losses are reclassified from accumulated other comprehensive income to the income statement as a component of natural gas and oil revenues in the period the hedged production occurs. If any ineffectiveness occurs, amounts are recorded directly to natural gas and oil revenues. During the first three months of 2004, we recognized $1.0 million of ineffectiveness. The ineffectiveness was a result of changes at the end of the current period in the price differentials between the index price of the derivative contract, which uses a NYMEX index, and the index price for the point of sale for the cash flow that is being hedged, the majority of which is the Houston Ship Channel index.

### Change in Fair Value of Derivative Instruments

The following table summarizes the change in the fair value of our derivative instruments for each of the three -month periods from January 1 to March 31, 2004 and 2003 and provides the fair value at the end of each period.

| | Three Months Ended March 31, 2004 | | Three Months Ended March 31, 2003 | |
|---|---|---|---|---|
| | **Before Tax** | **After Tax** | **Before Tax** | **After Tax** |
| **Change in Fair Value of Derivatives Instruments** | | | | |
| Fair value of contracts at January 1 | $(36,862) | $(26,128) | $(38,772) | $(25,202) |
| (Gain) loss on contracts settled and realized | 12,549 | 8,157 | 35,167 | 22,859 |
| Fair value of new contracts when entered into during period | | | | |
| (Decrease) in fair value of all open contracts | (59,524) | (36,266) | (52,971) | (34,431) |
| | $(83,837) | $(54,237) | $(56,576) | $(36,774) |

| | | | | |
|---|---|---|---|---|
| Fair value of contracts outstanding at March 31 | | | | |

**Derivatives in Place as of the Date of Our Report**

The following table summarizes, on a monthly basis, our natural gas hedges in place for 2004 and 2005. Subsequent to March 31, 2004, we have not entered into any new hedge contracts. For each month of 2004, we have hedged approximately 70% of our estimated production or a total of 240,000 million British thermal units per day or MMBtu/day. For the remaining nine months of 2004, our floor price will average $4.264/MMBtu on 240,000 MMBtu/day and our ceiling price will average $5.845/MMBtu on 240,000 MMBtu/day. For each calendar month of 2005, we have 200,000 MMBtu/day hedged with an effective floor price of $4.567 and an effective ceiling price of $5.456. All amounts in the table below are in thousands, except for prices.

Table of Contents

| Natural Gas Hedges | Fixed Price Swaps | | Collars | | |
|---|---|---|---|---|---|
| Period | Volume (MMBtu) | NYMEX Contract Price | Volume (MMBtu) | NYMEX Contract Price Floor | Ceiling |
| April 2004 | 1,200 | $4.960 | 6,000 | $4.125 | $6.023 |
| May 2004 | 1,240 | 4.960 | 6,200 | 4.125 | 6.023 |
| June 2004 | 1,200 | 4.960 | 6,000 | 4.125 | 6.023 |
| July 2004 | 1,240 | 4.960 | 6,200 | 4.125 | 6.023 |
| August 2004 | 1,240 | 4.960 | 6,200 | 4.125 | 6.023 |
| September 2004 | 1,200 | 4.960 | 6,000 | 4.125 | 6.023 |
| October 2004 | 1,240 | 4.960 | 6,200 | 4.125 | 6.023 |
| November 2004 | 1,200 | 4.960 | 6,000 | 4.125 | 6.023 |
| December 2004 | 1,240 | 4.960 | 6,200 | 4.125 | 6.023 |
| January 2005 | 1,550 | 4.766 | 4,650 | 4.500 | 5.685 |
| February 2005 | 1,450 | 4.766 | 4,200 | 4.500 | 5.685 |
| March 2005 | 1,550 | 4.766 | 4,650 | 4.500 | 5.685 |
| April 2005 | 1,500 | 4.766 | 4,500 | 4.500 | 5.685 |
| May 2005 | 1,550 | 4.766 | 4,650 | 4.500 | 5.685 |
| June 2005 | 1,500 | 4.766 | 4,500 | 4.500 | 5.685 |
| July 2005 | 1,550 | 4.766 | 4,650 | 4.500 | 5.685 |
| August 2005 | 1,550 | 4.766 | 4,650 | 4.500 | 5.685 |
| September 2005 | 1,500 | 4.766 | 4,500 | 4.500 | 5.685 |
| October 2005 | 1,550 | 4.766 | 4,650 | 4.500 | 5.685 |
| November 2005 | 1,500 | 4.766 | 4,500 | 4.500 | 5.685 |
| December 2005 | 1,550 | 4.766 | 4,650 | 4.500 | 5.685 |

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

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

**Item 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 Securities and Exchange Commission s rules and forms. We carried out an evaluation under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-14 of the Exchange Act), as of the end of the period covered by this report. Based on that evaluation, our principal executive officer and principal financial officer concluded that, as of March 31, 2004, our disclosure controls and procedures are functioning effectively as designed. There have been no changes in our internal control over financial reporting that occurred during the most recent fiscal quarter prior to the end of the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

**Part II. Other Information**.

**Item 6. Exhibits and Reports on Form 8-K:**

(a) Exhibits:

| Exhibits | Description |
|---|---|
| 10.1 | Amended and Restated Credit Agreement dated April 1, 2004 among The Houston Exploration Company and 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 and Comerica Bank as Co-Documentation Agents. |
| 12.1 | Statement of computation of ratio of earnings to fixed charges. |
| 31.1 | Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 31.2 | Certification of John H. Karnes, Senior Vice President and Chief Financial Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 32.1 | Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| 32.2 | Certification of John H. Karnes, Senior Vice President and Chief Financial Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |

(b) Reports on Form 8-K:

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

Current Report on Form 8-K filed on April 30, 2004 to furnish under Item 12 - Results of Operations and Financial Conditions our earnings release for the quarterly period ending March 31, 2004.

Table of Contents

## 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 6, 2004 | William G. Hargett<br>*President and Chief Executive Officer* |
| | By: /s/ John H. Karnes |
| Date: May 6, 2004 | John H. Karnes<br>*Senior Vice President and Chief Financial Officer* |
| | By: /s/ James F. Westmoreland |
| Date: May 6, 2004 | James F. Westmoreland<br>*Vice President and Chief Accounting Officer* |

Table of Contents

## EXHIBIT INDEX

| Exhibits | Description |
|---|---|
| 10.1 | Amended and Restated Credit Agreement dated April 1, 2004 among The Houston Exploration Company and 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 and Comerica Bank as Co-Documentation Agents. |
| 12.1 | Statement of computation of ratio of earnings to fixed charges. |
| 31.1 | Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 31.2 | Certification of John H. Karnes, Senior Vice President and Chief Financial Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 32.1 | Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| 32.2 | Certification of John H. Karnes, Senior Vice President and Chief Financial Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |

(b) Reports on Form 8-K:

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

Current Report on Form 8-K filed on April 30, 2004 to furnish under Item 12 - Results of Operations and Financial Conditions our earnings release for the quarterly period ending March 31, 2004.