HOUSTON EXPLORATION CO
Form 10-Q
August 09, 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 June 30, 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	
(State or other jurisdiction of incorporation or organization)	**22-2674487** **(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 August 6, 2004, 28,059,784 shares of Common Stock, par value $.01 per share, were outstanding.

THE HOUSTON EXPLORATION COMPANY

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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 1933,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, intend, expect, continue, estimate, project or similar expressions. All statements under the caption 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 cannot guarantee that the anticipated future results will be realized.

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

- *the volatility of natural gas and oil prices;*
- *the requirement to take writedowns if natural gas and oil prices decline or if our finding and development costs continue to increase;*
- *our reserves have relatively short production lives;*
- *our ability to find, develop and acquire natural gas and oil reserves;*
- *the success 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,*
- *influence by our significant shareholder, 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 for the year ended December 31, 2003. 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 through May 31, 2004, our subsidiary on a consolidated basis. Unless otherwise stated, all reserve and production quantities are expressed net to our interests.

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Part I. Financial Information

Item 1. Consolidated Financial Statements (unaudited)

THE HOUSTON EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

	June 30, 2004	December 31, 2003
Assets:		
Cash and cash equivalents	$ 15,109	$ 2,569
Accounts receivable	113,436	87,949
Accounts receivable Affiliate	5,763	6,733
Derivative financial instruments		3,458
Inventories	1,117	1,071
Deferred tax asset	26,408	19,644
Prepayments and other	2,925	5,818
Total current assets	164,758	127,242
Natural gas and oil properties, full cost method		
Unevaluated properties	136,699	134,491
Properties subject to amortization	2,403,135	2,324,011
Other property and equipment	10,898	12,617
	2,550,732	2,471,119
Less: Accumulated depreciation, depletion and amortization	1,226,281	1,099,990
	1,324,451	1,371,129
Other non-current assets	14,831	10,694
Total Assets	$1,504,040	$1,509,065
Liabilities:		
Accounts payable and accrued expenses	$ 100,706	$ 83,983
Derivative financial instruments	75,450	35,592
Asset retirement obligations	3,628	7,703
Total current liabilities	179,784	127,278
Long-term debt and notes	285,000	302,000

Derivative financial instruments	30,938	4,728
Deferred federal income taxes	259,343	251,425
Asset retirement obligations	77,817	84,654
Other deferred liabilities	10,555	3,446
Total Liabilities	843,437	773,531
Commitments and Contingencies (see Note 3)		
Stockholders Equity:		
Common Stock, $.01 par value, 50,000,000 shares authorized and 28,033,116 shares issued and outstanding at June 30, 2004, and 31,437,581 shares issued and outstanding at December 31, 2003, respectively	280	315
Additional paid-in capital	248,182	366,781
Unearned compensation	(383)	(808)
Retained earnings	480,414	395,374
Accumulated other comprehensive income	(67,890)	(26,128)
Total Stockholders Equity	660,603	735,534
Total Liabilities and Stockholders Equity	$1,504,040	$1,509,065

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

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THE HOUSTON EXPLORATION COMPANY

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

	Three Months Ended June 30, 2004	Three Months Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(unaudited)		(unaudited)	
Revenues:				
Natural gas and oil revenues	$172,578	$120,388	$324,212	$248,786
Other	198	244	446	849
Total revenues	172,776	120,632	324,658	249,635
Operating expenses:				
Lease operating	12,499	11,669	25,205	23,315
Severance tax	3,891	3,222	6,948	7,527
Transportation expense	3,169	2,696	5,905	5,188
Asset retirement accretion expense	1,190	826	2,478	1,652
Depreciation, depletion and amortization	67,192	47,724	128,156	93,378
General and administrative, net	9,761	4,204	15,849	8,088
Total operating expenses	97,702	70,341	184,541	139,148
Income from operations	75,074	50,291	140,117	110,487
Other (income) expense	(378)	3,616	(268)	(6,962)
Interest expense, net	2,306	2,160	4,593	4,426
Income before income taxes	73,146	44,515	135,792	113,023
Provision for taxes	27,796	15,592	50,752	39,631
Income before cumulative effect of change in accounting principle	45,350	28,923	85,040	73,392
Cumulative effect of change in accounting principle				(2,772)
Net income	$ 45,350	$ 28,923	$ 85,040	$ 70,620
Earnings per share:				
Net income per share basic				
Income before cumulative effect of change in accounting principle	$ 1.49	$ 0.93	$ 2.74	$ 2.37

Cumulative effect of change in accounting principle				(0.09)
Net income per share basic	$ 1.49	$ 0.93	$ 2.74	$ 2.28
Net income per share fully diluted				
Income before cumulative effect of change in accounting principle	$ 1.47	$ 0.93	$ 2.72	$ 2.36
Cumulative effect of change in accounting principle				(0.09)
Net income per share fully diluted	$ 1.47	$ 0.93	$ 2.72	$ 2.27
Weighted average shares outstanding basic	30,547	30,987	31,072	30,974
Weighted average shares outstanding fully diluted	30,810	31,095	31,262	31,082

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

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THE HOUSTON EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(unaudited)	
Operating Activities:		
Net income	$ 85,040	$ 70,620
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	128,156	93,378
Deferred income tax expense	26,061	39,573
Asset retirement accretion expense	2,478	1,652
Ineffectiveness of derivative instruments	1,700	
Amortization of premium on derivative instruments	3,576	
Stock compensation expense	1,329	101
Debt extinguishment	211	1,626
Cumulative effect of change in accounting principle		2,772
Changes in operating assets and liabilities:		
Increase in accounts receivable	(24,517)	(34,163)
Increase in inventories	(46)	(115)
Decrease in prepayments and other	2,893	7,308
Increase in other assets	(2,794)	(12,398)
Increase in accounts payable and accrued expenses	16,723	13,910
Increase in other deferred liabilities	7,109	1,348
Net cash provided by operating activities	247,919	185,612
Investing Activities:		
Investment in property and equipment	(165,436)	(138,348)
Assets retired and abandoned	(2,569)	
Proceeds from dispositions	73,138	
Net cash used in investing activities	(94,867)	(138,348)
Financing Activities:		
Proceeds from long-term borrowings	184,000	228,000
Repayments of long-term borrowings	(201,000)	(185,000)
Debt issue costs	(1,555)	(4,108)
Proceeds from issuance of common stock from exercise of stock options	16,455	2,460
Proceeds from issuance of common stock	310,567	79,200
Exchange of common stock	(448,979)	
Repurchase of common stock		(79,200)

Net cash (used in) provided by financing activities	(140,512)	41,352
Increase in cash and cash equivalents	12,540	88,616
Cash and cash equivalents, beginning of period	2,569	18,031
Cash and cash equivalents, end of period	$ 15,109	$ 106,647
Supplemental Information:		
Cash paid for interest	$ 7,817	$ 6,439
Cash paid for income taxes	$ 16,900	$ 10,900

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 primary areas of operations are South Texas, offshore in the shallow waters of the Gulf of Mexico and the Arkoma Basin of Oklahoma and Arkansas. During 2003, we began operations in the Rocky Mountain region, with an initial focus in the Uinta Basin of Northeastern Utah. We divested our Appalachian Basin assets on June 2, 2004 in connection with the KeySpan Exchange transaction described below.

We were founded by KeySpan Corporation in December 1985 and completed an initial public offering in 1996. KeySpan is a diversified energy provider whose principal natural gas distribution and electric generation operations are located in the Northeastern United States. As a result of an asset exchange transaction with KeySpan completed on June 2, 2004 and described below, KeySpan s ownership in the outstanding shares of our common stock was reduced from approximately 54% to 24%.

KeySpan Exchange and Offering

On June 2, 2004, we completed an asset exchange transaction with KeySpan pursuant to which we redeemed and cancelled 10,800,000 shares of our common stock owned by KeySpan in exchange for all the stock of Seneca-Upshur Petroleum, Inc., our wholly-owned subsidiary, to which we contributed all of our Appalachian Basin assets valued at $60 million and $389 million in cash for a total exchange value of $449 million. This transaction is referred to as the KeySpan Exchange. The KeySpan Exchange is intended to qualify as a tax-free exchange under Section 355(a) of the Internal Revenue Code.

To fund the cash portion of the exchange, on June 2, 2004, we sold 6,200,000 shares of our common stock in a registered public offering at $48.00 per share, the (Offering) and contributed to Seneca-Upshur substantially all of the net proceeds from the Offering of $282 million together with an additional $107 million of proceeds from bank borrowings. We then conveyed to KeySpan all of the shares of Seneca-Upshur in exchange for 10,800,000 shares of our common stock.

On June 23, 2004, the underwriters of our Offering exercised a portion of their over-allotment option and we sold an additional 620,000 shares of common stock at $48.00 per share for net proceeds of $28.6 million. The proceeds from the over-allotment were used to reduce bank borrowings.

The net effect of our redemption and cancellation of the 10,800,000 shares received from KeySpan and our issuance of 6,820,000 new shares resulted in a net 3,980,000 decrease in the outstanding shares of our common stock, and thereby reduced KeySpan s ownership from approximately 54% to 24%. As a result of the KeySpan Exchange and Offering, our bank borrowings increased by a net $79 million and we incurred approximately $5.1 million in compensation and other expenses related to special bonuses awarded to executives and key employees who assisted in structuring and consummating the transactions. Finally, KeySpan agreed to reduce its representation on our Board of Directors from five to two directors and our Chief Executive Officer, William G. Hargett, was elected Chairman of the

Board replacing Robert B. Catell, Chairman and Chief Executive Officer of KeySpan, who remains on the Board as one of KeySpan s representatives.

Principles of Consolidation

On June 2, 2004, all of the shares of our wholly-owned subsidiary, Seneca-Upshur were conveyed to KeySpan in connection with the KeySpan Exchange. Subsequent to the transaction, Seneca-Upshur was no longer a subsidiary of Houston Exploration but is a wholly-owned subsidiary of KeySpan, and as a result, our financial statements reflect the consolidated results of Seneca-Upshur through May 31, 2004. Seneca-Upshur was our only subsidiary and prior to the KeySpan Exchange, our consolidated financial statements included our accounts and the accounts of Seneca-Upshur. All significant inter-company balances and transactions were eliminated.

Seneca-Upshur is in the exploration and production business in West Virginia with interests in Appalachian Basin assets. Because we account for our natural gas and oil assets under the full cost method of accounting, the disposition of our Appalachian Basin assets, which represented only a portion of our full cost pool, is not considered discontinued operations under SFAS 144.

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

Interim Financial Statements

Our balance sheet at June 30, 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 (SEC). 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 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.

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THE HOUSTON EXPLORATION COMPANY
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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 June 30, 2004	Three Months Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(in thousands, except per share data)			
Numerator:				
Income before cumulative effect of change in accounting principle	$45,350	$ 28,923	$ 85,040	$73,392
Cumulative effect of change in accounting principle				(2,772)
Net income	$45,350	$ 28,923	$ 85,040	$70,620
Denominator:				
Weighted average shares outstanding	30,547	30,987	31,072	30,974
Add dilutive securities: Stock options	263	108	190	108
Total weighted average shares outstanding and dilutive securities	30,810	31,095	31,262	31,082
Earnings per share basic:				
Income before cumulative effect of change in accounting principle	$ 1.49	$ 0.93	$ 2.74	$ 2.37
Cumulative effect of change in accounting principle				(0.09)
Net income per share basic	$ 1.49	$ 0.93	$ 2.74	$ 2.28
Earnings per share fully diluted:				

Income before cumulative effect of change in accounting principle	$ 1.47	$ 0.93	$ 2.72	$ 2.36
Cumulative effect of change in accounting principle				(0.09)
Net income per share fully diluted	$ 1.47	$ 0.93	$ 2.72	$ 2.27

The calculation of shares outstanding for fully diluted EPS does not include the effect of outstanding stock options to purchase 739,444 and 1,893,611 shares for the three months ended June 30, 2004 and 2003, respectively, and 1,156,348 and 1,898,559 shares for the six months ended June 30, 2004 and 2003, respectively, because to include would have an antidilutive effect on earnings per share.

Comprehensive Income

The table below summarizes our Comprehensive Income for the three-month and six-month periods ended June 30, 2004 and 2003, respectively.

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2004	**2003**	**2004**	**2003**
	(in thousands)			
Net income	$ 45,350	$28,923	$ 85,040	$ 70,620
Other comprehensive income, net of taxes:				
Unrealized gain (loss) on derivative instruments	(13,653)	(841)	(41,762)	(12,413)
Comprehensive income	$ 31,697	$28,082	$ 43,278	$ 58,207

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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 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 believe that substantially all of the costs included in our unevaluated property balance will be evaluated in the next four years.

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 sheet. This issue

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

relates only to balance sheet classification and presentation and we do not believe it will not have an affect on cash flows or results of operations. At June 30, 2004, if we applied the interpretation currently under discussion, undeveloped leasehold costs of $132.5 million and developed leasehold costs of $148.6 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 is in the process of finalizing a FASB Staff Position (SFAS 142-b) that will amend SFAS 141 and SFAS 142. The consensus will be effective when SFAS 142 b 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 (ARO) 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.

The following table describes the various components of our asset retirement liability during each of the six month periods ending June 30, 2004 and 2003, respectively. ARO liability includes amounts classified as both current and long-term.

	Six Months Ended June 30,	
	2004	**2003**
	(in thousands)	
ARO liability at January 1	$ 92,357	$57,197
Additions from drilling	3,281	2,962
ARO accretion expense	2,478	1,652

Assets sold	(12,714)	
Assets retired and abandoned	(3,957)	
ARO liability at June 30	$ 81,445	$61,811

Derivative Instruments and Hedging Activities

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

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(unaudited)

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 six months of 2004, our net income includes an unrealized loss of $1.7 million ($1.1 million net of tax), of which $0.7 million ($.5 million net of tax) was incurred during the second quarter of 2004, which represents the ineffective portion of our derivative instruments that were not eligible for deferral. 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 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 June 30, 2004, we recorded an unrealized loss in Accumulated Other Comprehensive Income of $67.9 million, net of tax. Any loss will realized in future earnings at the time of the related sales of natural gas production applicable to specific hedges. However, these amounts could vary materially as a result of changes in market conditions.

Accounting for Stock Options and Restricted Stock

Effective 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 June 30, 2004 and 2003, we recognized gross compensation expense of $449,000 and $45,000, respectively, for stock options granted during these periods together with $363,000 and $21,000, respectively, for compensation expense relating to restricted stock. For the corresponding six-month periods ended June 30, 2004 and 2003, gross compensation expense for stock options was $904,000 and $59,000, respectively, and $425,000 and $21,000, respectively, for restricted stock.

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 and six-month periods ended June 30, 2004 and 2003. Amounts are in thousands, except per share data.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(in thousands except per share data)			
Net income as reported	$45,350	$ 28,923	$ 85,040	$70,620

Add: Stock-based compensation expense included in net income, net of tax	424	43	655	66
Less: Stock-based compensation expense using fair value method, net of tax	(1,466)	(1,102)	(2,733)	(2,189)
Net income pro forma	$44,308	$ 27,864	$ 82,962	$68,497
Net income per share as reported	$ 1.49	$ 0.93	$ 2.74	$ 2.28
Net income per share fully diluted as reported	1.47	0.93	2.72	2.27
Net income per share pro forma	$ 1.45	$ 0.90	$ 2.67	$ 2.21
Net income per share fully diluted pro forma	1.44	0.90	2.66	2.20

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NOTE 2 Long-Term Debt and Notes

	June 30, 2004	December 31, 2003
	(in thousands)	
Senior Debt:		
Revolving bank credit facility, due April 1, 2008	$110,000	$ 127,000
Subordinated Debt:		
7% senior subordinated notes, due June 15, 2013	175,000	175,000
Total long-term debt and notes	$285,000	$ 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 June 30, 2004, the quoted market value of our $175 million of 7% senior subordinated notes was 96.3% of the $175 million carrying value or $168.5 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 and restated on April 1, 2004, primarily to increase the size of the facility and was then amended again on June 2, 2004, in conjunction with the KeySpan Exchange. As amended, the facility 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. Amounts available for borrowing under the credit facility are limited to a borrowing base. On April 1, 2004, our borrowing base was increased from $300 million to $375 million, and on June 2, 2004, was reduced from $375 million to $340 million as a result of the disposition of our Appalachian Basin assets. Pursuant to the reduction in our borrowing base, we incurred $0.2 million debt extinguishment expenses during the second quarter of 2004 relating to the write-off of a portion of our debt issue costs. The $0.2 million is included in the line item Other (income) expense on our Statement of Operations. The $340 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 available for the issuance of letters of credit. Outstanding borrowings are unsecured and rank senior in right of payment to our $175 million 7% subordinated notes. The amended facility matures on April 1, 2008. At June 30, 2004, we had $110 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:

on base rate loans, at a fluctuating rate, or base rate, equal to the sum of (a) the greater of the Federal funds rate plus 0.5% or Wachovia s prime rate plus (b) a variable margin between 0.00% and 0.50%, depending on the amount of borrowings outstanding under the credit facility, or

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, guarantees, liens, leases and certain investments. The credit facility also restricts and limits our ability to pay cash dividends, to purchase or redeem our stock and to sell or encumber our assets. Financial covenants require us to, among other things:

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

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

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not hedge more than 85% of our production during any calendar year (which was increased, pursuant to the April 1, 2004, amendment, from 80% during each of the twelve-month periods of 2003 and 2004, and not more than 70% during any 12-month period after 2004.)

At June 30, 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 that decreases yearly from 3.5% in 2008 to 0% in 2011 and thereafter. In addition, at any time prior to June 15, 2006, we may redeem up to a maximum of 35% of the aggregate principal amount with the net proceeds of one or more equity offerings at a price equal to 107% of the principal amount, plus accrued and unpaid interest and liquidated damages, if any. The notes are general unsecured obligations and rank subordinate in right of payment to all existing and future senior debt, including the revolving bank credit facility, and will rank senior or equal in right of payment to all existing and future subordinated indebtedness.

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

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

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

A change of control is:

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

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

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

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

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.

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NOTE 4 Related Party Transactions

KeySpan Exchange

To facilitate the KeySpan Exchange (see Note 1 *KeySpan Exchange and Offering*), we entered into a Distribution Agreement with KeySpan that defines each company s rights and obligations with respect to the exchange transaction. The Distribution Agreement contains, among other provisions, customary representations and warranties concerning our Appalachian Basin properties, including title, regulatory compliance and environmental matters, along with limited indemnification obligations. Pursuant to the Distribution Agreement, the two companies also entered into a Tax Matters Agreement, which generally provides that each party would be responsible for its own tax consequences if the KeySpan Exchange fails to qualify as a tax-free transaction. In addition, we entered into a Transition Services Agreement pursuant to which we will provide KeySpan with transitional services with respect to the Appalachian Basin assets for a fee of $27,000 per month until March 31, 2005. Finally, we amended and restated our registration rights agreement with KeySpan. KeySpan is restricted from increasing their ownership of our shares (approximately 6.6 million shares subsequent to the exchange transaction) for a period of three years. In addition, both companies agreed with the underwriters of the Offering not to issue or sell shares of our common stock, except in connection with employee benefit plans, for the period ending August 24, 2004.

NOTE 5 Acquisitions and Dispositions

Disposition and Exchange of Appalachian Basin Assets

In connection with the KeySpan Exchange on June 2, 2004 (see Note 1 *KeySpan Exchange and Offering*), we divested all of our Appalachian Basin assets with an agreed upon value of $60 million. Pursuant to an Asset Contribution Agreement, we contributed to Seneca-Upshur all of the assets relating solely to our Appalachian Basin assets that were not already owned by Seneca-Upshur, and Seneca-Upshur assumed all of the liabilities relating to the Appalachian Basin assets for which it was not already liable. In the KeySpan Exchange, all of the stock of Seneca-Upshur was then conveyed to KeySpan and effective June 1, 2004, Seneca-Upshur became an indirect wholly-owned subsidiary of KeySpan.

Our Appalachian property base was located primarily in central West Virginia and included the Belington, Clarksburg and Seneca Upshur Fields located in Barbour, Randolph, Upshur and Mingo Counties of West Virginia and included the assets acquired on December 31, 2003, from EnerVest East Limited Partnership located adjacent to our existing base in the Crawford and Pennsboro Fields in Lewis, Harrison, Tyler and Ritchie Counties of West Virginia and the Waynesburg and Yatesboro Fields in Greene and Armstrong Counties of southwestern Pennsylvania. As of June 1, 2004, our Appalachian Basin properties had 51.2 Bcfe of estimated proved reserves with average daily production of approximately 8 MMcfe/day, which represented approximately 3% of our total daily production. We had approximately 207,000 gross (129,000 net) acres under lease and owned working interests in approximately 1,414 gross (1,035 net) wells, of which we operated approximately 92%. Our average working interest was 73%.

Sale of Onshore South Louisiana Properties

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

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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-Q, as well as our Annual Report on Form 10-K for the year ended December 31, 2003.

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 primary areas of operations are South Texas, offshore in the shallow waters of the Gulf of Mexico and the Arkoma Basin of Oklahoma and Arkansas. During 2003, we began operations in the Rocky Mountain region, with an initial focus in the Uinta Basin of Northeastern Utah. We divested our Appalachian Basin assets on June 2, 2004, in connection with the KeySpan Exchange transaction described in Note 1 *Our Business KeySpan Exchange and Offering*. 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.

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. For the first six months of 2004, the use of certain types of derivative instruments has prevented us from realizing the full benefit of upward price movements and may continue to do so in future periods.

Principal Components of Our Cost Structure:

Lease Operating Expenses. 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. Combined, 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. We capitalize G&A directly related to our acquisition, exploration and development activities.

Interest. We typically finance acquisitions with borrowings under our revolving bank credit facility, and longer term, with publicly 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 Obligations. Asset retirement obligations represent the estimated future abandonment costs of tangible long-lived assets such as platforms, wells, service assets, pipelines, and other facilities. We estimate the fair value of an asset s retirement obligation in the period in which the liability is incurred, if a reasonable estimate can be made. We employ a present value technique to estimate the fair value of an asset retirement obligation, which reflects certain assumptions, including an inflation rate, our credit-adjusted, risk-free interest rate, the estimated settlement date of the liability and the estimated current cost to settle the liability 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 June 30, 2004, if we applied the interpretation currently under discussion, undeveloped leasehold costs of $132.5 million and developed leasehold costs of $148.6 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, which 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 (SFAS 142-b) that will amend SFAS 141 and SFAS 142. The consensus will be effective when the SFAS 142-b has been finalized.

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Overview of Second Quarter 2004

Production growth from exploration and development drilling in all of our primary areas (South Texas, offshore and the Arkoma Basin) combined with the production added from the Gulf of Mexico properties acquired during the fourth quarter of 2003, together with strong energy commodity prices, were the primary factors behind results for operations, earnings and cash flows during the second quarter of 2004. The increase in our cash flows allowed for continued deployment of capital for drilling at levels established during the first quarter of 2004 and the continued repayment of bank debt. During the second quarter of 2004:

We completed the KeySpan Exchange and Offering as described in Note 1 *Our Business*, and as a result, we increased the public float of our common stock to approximately 76% and reduced KeySpan s ownership interest from approximately 54% to 24%;

We generated $45.3 million in net income, an increase of 57% from the second quarter of 2003, and an increase of 14% from the $39.7 million generated in the first quarter of 2004;

We produced a total of 32 Bcfe and increased our average daily production rate by 20% quarter-over-quarter to a record 351 MMcfe, and increased by 6% sequentially from of an average of 332 MMcfe per day during the first quarter of 2004;

We drilled 48 wells, 41 of which were successful, with 2 successful wells offshore, 12 in South Texas, 19 in Arkoma, 1 in East Texas and 7 in the Uinta Basin; and,

We generated $116.8 million in net cash flows from operating activities, invested a net $80.2 million in natural gas and oil properties, and increased borrowings under our revolving bank credit facility by a net $40 million.

	Three Months Ended June 30,				**Six Months Ended June 30,**			
Summary Operating Information:	**2004**	**2003**	**Variance**		**2004**	**2003**	**Variance**	
			(in thousands)					
Operating revenues	$172,776	$120,632	$52,144	43%	$324,658	$249,635	$75,023	30%
Operating expenses	97,702	70,341	27,361	39%	184,541	139,148	45,393	33%
Income from operations	75,074	50,291	24,783	49%	140,117	110,487	29,630	27%
Net income	45,350	28,923	16,427	57%	85,040	70,620	14,420	20%
Production:								
Natural gas (MMcf)	30,138	24,634	5,504	22%	58,270	49,019	9,251	19%
Oil (MBbls)	304	328	(24)	-7%	652	585	67	11%
Total (MMcfe) (1)	31,962	26,602	5,360	20%	62,182	52,529	9,653	18%
Average daily production (MMcfe/d)	351	292	59	20%	342	290	52	18%
Average Sales Prices:								
Natural Gas (per Mcf) realized (2)	$ 5.39	$ 4.54	$ 0.85	19%	$ 5.19	$ 4.73	$ 0.46	10%
Natural Gas (per Mcf) unhedged	5.85	5.16	0.69	13%	5.65	5.76	(0.11)	-2%
Oil (per Bbl) realized (2)	33.63	26.18	7.45	28%	33.02	28.55	4.47	16%
Oil (per Bbl) unhedged	33.63	25.95	7.68	30%	33.02	29.24	3.78	13%

(1) 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.

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

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Natural Gas and Oil Revenues

For the second quarter of 2004, the 43% increase in operating revenues was primarily a result of the combination of the 20% increase in production and the 19% increase in realized natural gas prices. Correspondingly, for the first six months of 2004, the 30% increase in operating revenues was a combination of the 18% increase in production, the 10% increase in realized natural gas prices and the narrowing of our hedge loss by $23.9 million.

Production Volume

The 20% increase in production for the current quarter is a result of newly developed production, both onshore and offshore, combined with the production added from Gulf of Mexico properties acquired during the fourth quarter of 2003.

Onshore, our daily production rates increased 12% from an average of 171 MMcfe per day during the second quarter of 2003 to 191 MMcfe per day during the second quarter of 2004. In the Arkoma Basin, we are experiencing the full impact of the accelerated drilling program initiated in 2003 as we added 12 MMcfe per day in newly developed production. With three rigs drilling since the beginning of 2004, Arkoma production reached a record of 35 MMcfe/day during the second quarter compared to 23 MMcfe/day during the second quarter of 2003. In South Texas, with six rigs drilling, we also experienced production growth as we added approximately 9 MMcfe/day. Production increased to an average of 148 MMcfe/day during the second quarter of 2004 compared to 139 MMcfe/day in the second quarter of 2003.

Offshore, our production increased 32% from an average of 121 MMcfe per day during the second quarter of 2003 to an average of 160 MMcfe per day during the second quarter of 2004. We added 46 MMcfe/day in newly developed production, of which 20 MMcfe/day was attributable to development drilling at High Island A283. During the quarter, we completed and brought on-line our sixth development well at High Island A283 since January 2004. High Island A283 was acquired in mid-October 2003 as part of our acquisition of Gulf of Mexico properties from Transworld. The acquired production from the Transworld properties accounted for approximately 34 MMcfe/day of our second quarter increase. Offsetting the increases from the newly developed and the acquired production were declines from existing and maturing fields totaling 41 MMcfe per day.

For the six-month period ended June 30, 2004, production increased 18% from 290 MMcfe/day during the first half of 2003 to 342 MMcfe/day during the first half of 2004. During the first six months of 2004, we added 12 MMcfe/day in Arkoma, 5 MMcfe/day in South Texas and 35 MMcfe/day offshore. Offshore, the increase is comprised of:

- 41 MMcfe/day in newly developed production from new wells brought on-line since the end of the second quarter of 2003 at High Island 47, A283 and 115, Galveston Island 389/424, Eugene Island 159 and East Cameron 280;

- 32 MMcfe/day in acquired production as a result of the Transworld acquisition in mid-October 2003; offset in part by,

- a decline of 38 MMcfe/day in production from existing and maturing fields.

Commodity Prices and Effects of Hedging

Our average unhedged or sales price for natural gas increased by 13% from $5.16 per Mcf during the second quarter of 2003 to $5.85 per Mcf during the second quarter 2004.

Included in natural gas revenues for the second quarter of 2004 is a loss of $13.9 million from natural gas hedging activities, which includes an unrealized loss of $0.7 million representing the ineffective portion of our derivative instruments that are not eligible for deferral under SFAS 133. As a result of the loss from hedging activities, we realized an average natural gas price during the second quarter of 2004 of $5.39 per Mcf that was 92% or $0.46 lower than our average sales price. For the second quarter of 2003, we incurred a hedge loss from natural gas derivatives of $15.4 million resulting in an average realized price of $4.54 per Mcf that was 88% or $0.62 per Mcf lower than our sales price.

For the first six months of 2004, the increase in our realized price was primarily a result of the narrowing of our losses from hedging activities for the period as average sales prices decreased slightly by 2% from an average of $5.76 per Mcf during the first half of 2003 to $5.65 Mcf during the first half of 2004. Our hedge loss for the first six months of 2004 of $26.5 million decreased by 47% or by $23.9 million from the loss of $50.4 million during the first six months of 2003. For the first six months of 2004, our realized price was 92% or $0.46 per Mcf lower than our average unhedged natural gas price, which compares a realized price during the first half of 2003 that was 82% or $1.03 per Mcf lower than the unhedged price.

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Operating Expenses

Our overall operating expenses increased during the second quarter and the current six-month period primarily as a result of higher depreciation, depletion and amortization rates and higher general and administration expenses that included $4.4 million in compensation expenses relating to the consummation of the KeySpan Exchange. Lease operating expense, while up on an absolute basis due to our fourth quarter 2003 Gulf of Mexico acquisition and the continuing maturation of our base properties, is down on a unit basis as a result of our increased production volume.

	Three Months Ended June 30,				Six Months Ended June 30,			
Operating Expenses per Mcfe	**2004**	**2003**	**Variance**		**2004**	**2003**	**Variance**	
Lease operating expense	$0.39	$0.44	$(0.05)	-11%	$0.41	$0.44	$(0.03)	-7%
Severance tax	0.12	0.12			0.11	0.14	(0.03)	-21%
Transportation expense	0.10	0.10			0.09	0.10	(0.01)	10%
Asset retirement accretion expense	0.04	0.03	0.01	33%	0.04	0.03	0.01	33%
Depreciation, depletion and amortization	2.10	1.79	0.31	17%	2.06	1.78	0.28	16%
General and administrative, net	0.31	0.16	0.15	94%	0.25	0.15	0.10	67%
Total operating expenses per unit of production	$3.06	$2.64	$ 0.42	16%	$2.96	$2.64	$ 0.32	12%

Lease Operating Expense. Lease operating expense increased 7% quarter-over-quarter and 8% period-over-period. The increases for both the current quarter and the current six month period are due to the continued expansion of our operations combined with the higher lease operating expense associated with the offshore properties acquired in mid-October 2003 from Transworld offset in part by reduced workover expenses for 2004. On a per unit basis, the $0.05 or 11% decrease for the quarter is due to the 20% increase in production during the second quarter of 2004. For the year, the $0.03 or 7% decrease in lease operating expense is due to the 18% increase in production during the first six months of 2004.

Severance Tax. Severance tax is a function of volume and revenues generated from onshore production. For the quarter, severance tax is higher due to the 12% increase in onshore production; primarily from our Arkoma properties, as our South Texas properties are exempt or taxed at reduced rates because of their high-cost/tight-sand designation, combined with the 13% increase in wellhead prices for natural gas. On a per unit basis, severance tax is unchanged. For the six-month period, average wellhead prices are down by 2% and onshore production is up by 10%, resulting in a decrease in severance tax expense and severance tax per Mcfe.

Depreciation, Depletion and Amortization. The increase in our depreciation, depletion and amortization expense for the current quarter and the first half of 2004 was primarily a result of a higher depletion rate combined with a 20% increase in production for the quarter and an 18% increase in production for the six-month period. The increase in our depletion rate is primarily a result of higher finding costs and fewer reserve additions. During the first six months of 2004, we drilled a total of 15 dry holes, 13 of which were onshore and two were offshore exploratory wells. In addition, for the second quarter of 2004, we estimate that $0.05 of the increase in the rate was due to the disposition of our Appalachian Basin assets, which represented an estimated 51.2 Bcfe in total net proved reserves as of June 1, 2004.

Asset Retirement Accretion Expense. The increase in ARO accretion during the second quarter of 2004 and the six month period 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 $16.7 million in reductions during the first six months of 2004 as a result of abandonment of offshore properties, disposition of our South Louisiana properties in February 2004 and our Appalachian Basin properties in June 2004.

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

	Three Months Ended June 30,				Six Months Ended June 30,			
General and Administrative per Mcfe	**2004**	**2003**	**Variance**		**2004**	**2003**	**Variance**	
Gross general and administrative expense	$ 0.44	$ 0.28	$ 0.16	57%	$ 0.40	$ 0.29	$ 0.11	38%
Operating overhead reimbursements	(0.02)	(0.02)			(0.02)	(0.02)		
Capitalized general and administrative	(0.11)	(0.10)	(0.01)	10%	(0.13)	(0.12)	(0.01)	8%
General and administrative expense, net	$ 0.31	$ 0.16	$ 0.15	94%	$ 0.25	$ 0.15	$ 0.10	67%

During the second quarter of 2004 we incurred approximately $4.4 million in compensation expenses related to the KeySpan Exchange transaction. This amount included $4.1 million in special bonuses awarded to executives and key employees who assisted in structuring and consummating the KeySpan Exchange and the Offering. In addition, we incurred $0.3 million in expenses relating to the accelerated vesting of restricted stock held by directors who resigned or retired from our Board of Directors in June. On a per-unit of production basis, these additional compensation expenses resulted in a $0.14 per Mcfe increase for the quarter and a $0.07 increase for the six-month period. Excluding the effect of the additional compensation expenses, gross general and administrative expense would have been $0.30 per Mcfe for the second quarter of 2004 and net general and administrative expense would have been $0.17 reflecting increases of $0.02 or 7% for gross general and administrative expense and $0.01 or 6% for net general and administrative expense from the second quarter of 2003.

Excluding the compensation expenses associated with the KeySpan Exchange, 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.

Other Income and Expense, Interest and Taxes

Other Income and Expense. For the second quarter and first six months of 2004, other income was minimal as we are near the end of our severance tax recovery project. 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. For the second quarter of 2004, Other Income and Expense includes two items: (i) income of $0.5 million ($0.3 million net of tax) related to refunds of prior year s severance tax expense; and (ii) debt extinguishment expenses of $0.2 million incurred pursuant to the reduction of the borrowing base on our revolving bank credit facility from $375 million to $340 million. The credit facility is reserve based and contains certain restrictions limiting the sale of assets, and due to the disposition of our Appalachian Basin assets as a component of the KeySpan Exchange, our borrowing base was reduced. For the second quarter of 2003, Other Income and Expense includes two components: (i) debt extinguishment expenses totaling $5.9 million ($3.9 million net of tax) incurred pursuant to the call and early redemption of our $100 million $8^{5}/_{8}$% senior subordinated notes due 2008; and (ii) income of $2.3 million ($1.5 million net of tax) related to refunds of prior year s severance tax expense. For the first six months of 2003, Other Income and Expense includes: (i) debt extinguishment expenses totaling $5.9 million ($3.9 million net of tax); and (ii) income of $12.9 million ($8.4 million net of tax) related to refunds of prior year s severance tax expense.

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Interest Expense, Net of Capitalized Interest.

	Three Months Ended June 30,				Six Months Ended June 30,			
Interest and Average Borrowings	**2004**	**2003**	**Variance**		**2004**	**2003**	**Variance**	
				(in thousands)				
Gross interest	$ 4,381	$ 3,981	$ 400	10%	$ 8,609	$ 7,618	$ 991	13%
Capitalized interest	(2,075)	(1,821)	(254)	14%	(4,016)	(3,192)	(824)	26%
Interest expense, net of capitalized	$ 2,306	$ 2,160	$ 146	7%	$ 4,593	$ 4,426	$ 167	4%
Average borrowings	$263,176	$229,582	$ 33,594	15%	$272,304	$239,847	$ 32,457	14%
Average interest rate	5.81%	6.43%	(0.62)%	-10%	5.70%	5.91%	(0.21)%	- 4%

For the second quarter of 2004 and for the six-month period, the increase in our gross interest was due in part to the increase in average borrowings offset in part by a decrease in our average rate. In June 2003, we replaced our fixed debt of $100 million at 8 % with new fixed debt of $175 million at 7%. For the year, average borrowings on our bank credit facility decreased by approximately $20 million compared to average borrowings during the first half of 2003 and our average borrowing rate decreased slightly from 3.49% for the first half of 2003 as compared to 3.41% during the first half of 2004. Capitalized interest is a function of unevaluated properties and the increase corresponds to the increase in our average unevaluated property balance for the quarter and the six-month period during 2004. The increase in unevaluated property is primarily a result of our October 2003 acquisition of Gulf of Mexico producing properties from Transworld.

Income Tax Provision. For the second quarter of 2004, our current provision includes $1.0 million relating to nondeductible executive compensation expense incurred as a result of a special bonus paid to our Chief Executive Officer in connection with the KeySpan Exchange. The 78% increase in income taxes for the second quarter of 2004 corresponds to the 64% increase in income before taxes. Our current provision increased to $16.5 million as we depleted our net operating loss carryforwards during 2003 and moved to a tax paying status, whereas during the second quarter of 2003, all federal income taxes were deferred. For the six-month period of 2004, income taxes increased by 28% and corresponds to the 20% increase in income before taxes. Our current provision for the six-month period increased to $24.7 million.

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 six months of 2004, we invested $164.7 million in natural gas and oil properties and $0.7 million in other property and equipment, spent $2.6 million to abandon offshore assets and divested $73.1 million in onshore assets, which included our South Louisiana assets in February and our Appalachian Basin assets in June. 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 half of 2004, we spent 30% offshore and

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63% onshore, with the balance of 7% on capitalized interest and general and administrative costs. During the first six months of 2004, we completed the drilling of 99 gross wells (81.4 net) of which 85% or 84 (69.2 net) were successful and 15 (12.2 net) were unsuccessful, with an additional 9 wells (7.1 net) in progress at the end of the period. During the second quarter, we drilled 48 gross wells (31.0 net) of which 85% or 41 (32.4 net) were successful and 7 (5.6 net) were unsuccessful. The table below details the components of our natural gas and oil expenditures during each of three-month and six-month periods ended June 30, 2004 and 2003.

Natural Gas and Oil Expenditures:	Three Months Ended June 30, 2004	Three Months Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(in thousands)			
Producing property acquisitions	$	$	$ 2,700	$
Leasehold and lease acquisition costs (1)	13,006	20,304	26,640	28,274
Development	58,600	45,835	116,696	79,206
Exploration	8,491	18,247	18,699	30,278
Total natural gas and oil capital expenditures	$80,097	$84,386	$164,735	$137,758

(1) For the three months ended June 30, 2004 and 2003, leasehold costs include capitalized interest and general and administrative expenses of $5.7 million and $4.7 million, respectively. For the corresponding six-month periods of 2004 and 2003, capitalized interest and general and administrative expenses included in leasehold costs totaled $11.8 million and $9.8 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 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 June 30, 2004. In addition to the contractual obligations listed on the table below, our balance sheet at June 30, 2004 reflects accrued interest payable on our revolving bank credit facility of approximately $10,000, 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 $15 million to $20 million during the second half of 2004.

	At June 30, 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	$110,000	$	$	$110,000	$
7% senior subordinated notes, due June 2013	175,000				175,000
Operating leases	7,831	770	4,501	2,560	
	292,831	770	4,501	112,560	175,000
Other Long-Term Obligations:					
Asset retirement obligations	81,445	3,628	7,999	11,700	58,118
Total contractual obligations and commitments	$374,276	$ 4,398	$12,500	$124,260	$233,118

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. If additional funding is needed to complete a significant acquisition, we may also access public markets for debt or equity. Our primary sources of cash during the first six months of 2004 were funds generated from operations and proceeds for the issuance of common stock through our public offering of 6.8 million shares of common stock and from the exercise of stock options. Cash was used to fund the KeySpan Exchange, exploration and development expenditures and to reduce debt under our revolving bank credit facility. We made

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aggregate cash payments of $7.8 million for interest and $16.9 million for taxes.

The following table summarizes the sources of cash during each of the six-month periods ended June 30, 2004 and 2003:

	Six Months Ended June 30,			
	2004	2003	Variance	% change
	(in thousands)			
Net income	$ 85,040	$ 70,620	$ 14,420	20%
Non-cash charges	163,511	139,102	24,409	18%
Cash from operations before changes in operating assets and liabilities	248,551	209,722	38,829	19%
Decrease (increase) in operating assets and liabilities	(632)	(24,110)	23,478	-97%
Net cash provided by operating activities	247,919	185,612	62,307	34%
Net cash (used) for investments in property and equipment	(94,867)	(138,348)	43,481	-31%
Net cash (used) provided by in financing activities	(140,512)	41,352	(181,864)	-440%
Net increase (decrease) in cash	$ 12,540	$ 88,616	$ (76,076)	-86%

At June 30, 2004, we had a working capital deficit of $14.0 million, long-term debt of $285 million (which includes $110 million in bank debt), 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 $75.5 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 six months of 2004 was primarily attributable to the increase in operating income primarily as a result of the 18% increase in average daily production for the current year combined with the 10% increase in realized natural gas prices and a decrease in our hedge loss. The fluctuations in operating assets and liabilities are caused by the timing of cash receipts and disbursements.

Access to Capital Markets. In March 2004, we filed a shelf registration statement with the SEC for the offering, from time to time, of up to $600 million of our common stock, preferred stock, depositary shares and debt securities, or a combination of any of these securities, as well as for the shares of our common stock owned by KeySpan. Subsequent to the June 2004 public offering of 6.8 million shares at $48.00 per share, the proceeds of which were used to finance a portion of the KeySpan Exchange transaction, we have approximately $267.4 million of capacity remaining under the shelf registration statement.

Pursuant to the terms of the 1996 registration rights agreement entered into with KeySpan, we registered KeySpan s 17.4 million shares of our common stock with the shelf registration statement filed in March 2004. The registration rights agreement was amended and restated pursuant to the KeySpan Exchange transaction on June 2, 2004. The registration rights agreement, as amended, provides KeySpan with certain registration rights with regard to its remaining shares of our common stock.

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.

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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 six months of 2004, we recognized $1.7 million of ineffectiveness, of which $0.7 million was recognized during the second quarter. 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 six-month periods from January 1 to June 30, 2004 and 2003, and provides the fair value at the end of each period.

	Six Months Ended June 30, 2004		Six Months Ended June 30, 2003	
Change in Fair Value of Derivatives Instruments:	**Before Tax**	**After Tax**	**Before Tax**	**After Tax**
	(in thousands)			
Fair value of contracts at January 1	$ (36,862)	$ (23,960)	$ (38,772)	$ (25,202)
Realized (gain) loss on contracts settled	23,953	15,569	50,446	32,790
Unrealized (gain) loss due to ineffectiveness of contracts	1,700	1,105		
Fair value of new contracts when entered into during period			5,288	3,437
(Decrease) in fair value of all open contracts	(95,179)	(61,866)	(69,542)	(45,202)

Fair value of contracts outstanding at June 30	$(106,388)	$(69,152)	$(52,580)	$(34,177)

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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 June 30, 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 six months of 2004, our floor price will average $4.264 per MMBtu on 240,000 MMBtu per day and our ceiling price will average $5.845 per MMBtu on 240,000 MMBtu per day. For each calendar month of 2005, we have 200,000 MMBtu per day hedged with an effective floor price of $4.567 per MMBtu and an effective ceiling price of $5.456 per MMBtu. All amounts in the following table are in thousands, except for prices.

Natural Gas Hedges	Fixed Price Swaps		Collars		
Period	Volume (MMBtu)	NYMEX Contract Price	Volume (MMBtu)	NYMEX Contract Price Floor	NYMEX Contract Price Ceiling
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. 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

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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 June 30, 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 2. Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities

The following table contains information about our purchases of equity securities during the second quarter of 2004.

	Our Purchases of Our Common Stock			
Period	**Total Number of Shares Purchased [1]**	**Average Price Paid per Share [1]**	**Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs**	**Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs**
April 1 to April 30, 2004				
May 1 to May 31, 2004				
June 1 to June 30, 2004	10,800,000	$41.57		
Total	10,800,000	$41.57		

(1) On May 24, 2004, we issued a press release announcing an exchange transaction with KeySpan Corporation pursuant to which we would redeemed and cancelled 10,800,000 shares of our common stock owned by KeySpan in exchange for all the stock of Seneca-Upshur, our wholly-owned subsidiary, to which we contributed all of our Appalachian Basin assets valued at $60 million and $389 million in cash for a total exchange value of $449 million. On June 2, 2004, we announced the completion of the transaction with KeySpan.

Item 4. Submission of Matters to a Vote of Security Holders

On June 3, 2004, we held our annual meeting of stockholders. All matters brought for a vote before the stockholders as listed in our proxy statement were approved as follows:

1. The election of the following 10 Directors to serve until our next annual meeting:

Director	Votes For	Votes Withheld
Robert B. Catell	25,622,660	5,643,581
John U. Clarke	31,012,586	253,675
David G. Elkins	30,933,096	331,145
Robert J. Fani (1)	25,662,650	5,603,591
William G. Hargett	26,662,964	4,603,277
Harold R. Logan, Jr.	30,968,511	297,730
Gerald Luterman (1)	26,479,784	4,786,457
Stephen W. McKessy	30,938,866	327,375
H. Neil Nichols (1)	26,461,240	4,805,001
Donald C. Vaughn	30,950,731	315,510

(1) Messrs. Fani, Luterman and Nichols resigned from our Board of Directors on June 2, 2004, pursuant to the consummation of the KeySpan Exchange transaction and the

resulting reduction in KeySpan s ownership interest in our common stock from approximately 54% to 24%.

2. The approval of The Houston Exploration Company 2004 Long-Term Incentive Plan

Votes For	Votes Against	Abstained	Broker Non-Votes
27,735,227	1,260,466	400,869	1,869,679

3. The appointment of Deloitte & Touche LLP as our independent public accountants for the fiscal year ending December 31, 2004.

Votes For	Votes Against	Abstained
31,187,538	72,716	5,987

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

(a) Exhibits:

Exhibits	Description
10.1(1)	First Amendment dated May 26, 2004 to the 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 dated June 2, 2004.
10.2	Distribution Agreement dated as of June 2, 2004 by and among The Houston Exploration Company, Seneca-Upshur Petroleum, Inc., THEC Holdings Corp. and KeySpan Corporation (filed as Exhibit 99.2 to our Current Report on Form 8-K dated June 30, 2004 (File No. 001-11899) and incorporated by reference).
10.3	Asset- Contribution Agreement dated June 2, 2004 between The Houston Exploration Company and Seneca-Upshur Petroleum, Inc. (filed as Exhibit 99.3 to our Current Report on Form 8-K dated June 30, 2004 (File No. 001-11899) and incorporated by reference).
10.4	Tax Matters Agreement dated as of June 2, 2004 by and among The Houston Exploration Company, Seneca-Upshur Petroleum, Inc., THEC Holdings Corp., and KeySpan Corporation (filed as Exhibit 99.4 to our Current Report on Form 8-K dated June 30, 2004 (File No. 001-11899) and incorporated by reference).
10.5	Transition Service Agreement dated June 2, 2004 between The Houston Exploration Company and Seneca-Upshur Petroleum, Inc. (filed as Exhibit 99.4 to our Current Report on Form 8-K dated June 30, 2004 (File No. 001-11899) and incorporated by reference).
10.6	Amended and Restated Registration Rights Agreement dated as of June 2, 2004 between The Houston Exploration Company and THEC Holdings Corp. (filed as Exhibit 99.6 to our Current Report on Form 8-K dated June 30, 2004 (File No. 001-11899) and incorporated by reference).

10.7(2)	2004 Long-Term Incentive Plan approved by vote of stockholders on June 3, 2004 (file as Appendix E to our Definitive Proxy Statement on Schedule 14 A dated June 3, 2004 (File No. 001-11899) and incorporated by reference).
12.1[(1)]	Statement of computation of ratio of earnings to fixed charges.
31.1[(1)]	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 302

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Exhibits	Description
	of the Sarbanes-Oxley Act of 2002.
31.2[1]	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[1]	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2[1]	Certification of John H. Karnes, Senior Vice President and Chief Financial Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(1) filed herewith

(2) Management contract or compensation plan.

(b) Reports on Form 8-K:

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

Current Report on Form 8-K filed on May 24, 2004, to report under Item 5 Other Events the KeySpan Exchange transaction and the offering of 6.2 million shares of our common stock, file as an exhibit under Item 7 our press release announcing the exchange transaction and offering and to furnish under Item 9 Regulation FD Disclosure a confirmation that the exchange and offering will not change our operational and financial guidance previously announced.

Current Report on Form 8-K filed on May 27, 2004, to report under Item 5 Other Events the pricing of our offering of 6.2 million shares of common stock and to file as an exhibit under Item 7: (i) the Underwriting Agreement dated May 26, 2004, among The Houston Exploration Company, and Lehman Brothers Inc. and Goldman, Sachs & Co., as representatives of the underwriters named therein; (ii) the opinion of King & Spalding LLP with respect to the legality of the common stock; (iii) consent of King & Spalding LLP; and (iv) our press release announcing the pricing of the common stock being offered.

Current Report on Form 8-K filed on June 4, 2004, to report under Item 5 Other Events the completion of the KeySpan Exchange and closing of the offering of 6.2 million shares of common stock and to file as exhibits under Item 7 the: (i) press release announcing the closing of the KeySpan Exchange and the Offering; (ii) Distribution Agreement dated June 2, 2004, among The Houston Exploration Company, Seneca-Upshur Petroleum, Inc., THEC Holdings Corp. and KeySpan Corporation; (iii) Asset Contribution Agreement dated June 2, 2004 between The Houston Exploration Company and Seneca-Upshur Petroleum, Inc.; (iv) Tax Matters Agreement dated as of June 2, 2004, by and among The Houston Exploration Company, Seneca-Upshur Petroleum, Inc., THEC Holding Corp. and KeySpan Corporation; and (v) Amended and Restated Registration Rights Agreement dated as of June 2, 2004, between The Houston Exploration Company and THEC Holding Corp.

Current Report on Form 8-K filed on June 24, 2004, to report under Item 5 Other Events the closing of the over-allotment offering and to file as an exhibit under Item 7 our press release announcing the closing of the over-allotment offering.

Current Report on Form 8-K filed on August 5, 2004, to furnish under Item 12 Results of Operations and Financial Condition our earnings release for the quarterly period ending June 30, 2004.

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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: August 6, 2004

William G. Hargett
Chairman, President and Chief Executive Officer

By: /s/ John H. Karnes

Date: August 6, 2004

John H. Karnes
Senior Vice President and Chief Financial Officer

By: /s/ James F. Westmoreland

Date: August 6, 2004

James F. Westmoreland
Vice President and Chief Accounting Officer

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INDEX TO EXHIBITS

Exhibits	Description
10.1(1)	First Amendment dated May 26, 2004 to the 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 dated June 2, 2004.
10.2	Distribution Agreement dated as of June 2, 2004 by and among The Houston Exploration Company, Seneca-Upshur Petroleum, Inc., THEC Holdings Corp. and KeySpan Corporation (filed as Exhibit 99.2 to our Current Report on Form 8-K dated June 30, 2004 (File No. 001-11899) and incorporated by reference).
10.3	Asset Contribution Agreement dated June 2, 2004 between The Houston Exploration Company and Seneca-Upshur Petroleum, Inc. (filed as Exhibit 99.3 to our Current Report on Form 8-K dated June 30, 2004 (File No. 001-11899) and incorporated by reference).
10.4	Tax Matters Agreement dated as of June 2, 2004 by and among The Houston Exploration Company, Seneca-Upshur Petroleum, Inc., THEC Holdings Corp., and KeySpan Corporation (filed as Exhibit 99.4 to our Current Report on Form 8-K dated June 30, 2004 (File No. 001-11899) and incorporated by reference).
10.5	Transition Service Agreement dated June 2, 2004 between The Houston Exploration Company and Seneca-Upshur Petroleum, Inc. (filed as Exhibit 99.4 to our Current Report on Form 8-K dated June 30, 2004 (File No. 001-11899) and incorporated by reference).
10.6	Amended and Restated Registration Rights Agreement dated as of June 2, 2004 between The Houston Exploration Company and THEC Holdings Corp. (filed as Exhibit 99.6 to our Current Report on Form 8-K dated June 30, 2004 (File No. 001-11899) and incorporated by reference).
10.7(2)	2004 Long-Term Incentive Plan approved by vote of stockholders on June 3, 2004 (file as Appendix E to our Definitive Proxy Statement on Schedule 14 A dated June 3, 2004 (File No. 001-11899) and incorporated by reference).
12.1(1)	Statement of computation of ratio of earnings to fixed charges.
31.1(1)	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2(1)	Certification of John H. Karnes, Senior Vice President and Chief Financial Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1(1)	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2(1)	

Certification of John H. Karnes, Senior Vice President and Chief Financial Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(1) filed herewith

(2) Management contract or compensation plan.