HOUSTON EXPLORATION CO
Form 10-Q
August 03, 2005

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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, 2005
OR
o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ___to ___
Commission File No. 001-11899

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

Delaware	**22-2674487**
(State or Other Jurisdiction of Incorporation or Organization)	**(IRS Employer Identification No.)**
1100 Louisiana, Suite 2000 Houston, Texas	**77002-5215**
(Address of Principal Executive Offices)	**(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 Act). Yes þ No o
As of August 2, 2005, 28,731,780 shares of Common Stock, par value $0.01 per share, were outstanding.

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Forward-Looking Statements and Other Information

All of the estimates and assumptions contained in this Quarterly Report on Form 10-Q (Quarterly Report) constitute forward-looking statements as that term is defined in Section 27A of the Securities Act of 1933, as amended (the Securities Act), and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). These statements use forward-looking words such as anticipate, believe, continue, expect, estimate, intend, may, potential, predict, project, should, target, goal, objective or other similar expressions and discuss forward-l information. Forward-looking statements include all statements under the caption Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations involving the discussion of the following:

- business strategy;
- natural gas and oil reserves;
- future production;
- expected realized natural gas and oil prices;
- expected costs and expenses;
- anticipated capital expenditures;
- future operating results;
- future cash flows and borrowings;
- pursuit of potential future acquisition opportunities;
- identified drilling locations; and
- sources of funding and the timing of exploration and development activities.

Although we believe that these forward-looking statements are based on reasonable assumptions, our expectations may not occur, and we cannot guarantee that the anticipated future results will be achieved. A number of factors could cause our actual future results to differ materially from 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;
- the relatively short production lives of our reserves;
- our ability to find, replace, develop and acquire natural gas and oil reserves;
- the maturity of North American gas basins;
- acquisition and investment risks;
- our ability to manage rising costs;
- our ability to meet our substantial capital requirements;

- our outstanding indebtedness;
- the uncertainty of estimates of natural gas and oil reserves and production rates;
- the inherent hazards and risks involved in our operations;
- dependence upon operations concentrated in three primary areas;
- drilling risks;
- our hedging activities;
- compliance with environmental and other governmental regulations;
- the competitive nature of our industry;
- weather risks and other natural disasters; and
- our customers ability to meet their obligations.

For additional discussion of these and other risks, uncertainties and assumptions, see Items 1 and 2. Business and Properties and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations contained in our Annual Report on Form 10-K for the year ended December 31, 2004. 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, our and Houston Exploratio we are describing The Houston Exploration Company including, through May 31, 2004, our former subsidiary Seneca-Upshur Petroleum, Inc., and subsequent to October 8, 2004, THEC, LLC and THEC, LP on a consolidated basis.

If you are not familiar with the natural gas and oil terms used in this Quarterly Report, please refer to the explanations of the terms under the caption Glossary of Natural Gas and Oil Terms included on pages G-1 through G-2 of our Annual Report on Form 10-K for the year ended December 31, 2004. When we refer to equivalents, we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one barrel of oil is equal to six thousand cubic feet of natural gas. Unless otherwise stated, all reserve and production quantities are expressed net to our interests.

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Part I. Financial Information
Item 1. Condensed Consolidated Financial Statements

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

	June 30, 2005	December 31, 2004
Assets:		
Cash and cash equivalents	$ 4,694	$ 18,577
Accounts receivable	102,006	103,069
Inventories	1,639	976
Deferred tax asset	50,031	24,101
Prepayments and other	2,710	9,107
Total current assets	161,080	155,830
Natural gas and oil properties, full cost method		
Unevaluated properties	150,642	122,691
Properties subject to amortization	3,029,981	2,777,097
Other property and equipment	12,147	11,740
	3,192,770	2,911,528
Less: Accumulated depreciation, depletion and amortization	1,505,748	1,363,272
	1,687,022	1,548,256
Other non-current assets	17,080	18,491
Total Assets	$1,865,182	$1,722,577
Liabilities:		
Accounts payable and accrued expenses	$ 131,857	$ 118,971
Derivative financial instruments	141,331	68,081
Asset retirement obligation	1,486	662
Total current liabilities	274,674	187,714
Long-term debt and notes	330,000	355,000
Derivative financial instruments	90,229	7,068
Deferred income taxes	290,123	288,069
Asset retirement obligation	95,506	91,084
Other non-current liabilities	12,085	10,722
Total Liabilities	1,092,617	939,657

Commitments and Contingencies (see Note 4)		
Stockholders Equity:		
Preferred Stock, $0.01 par value, 5,000,000 shares authorized and no shares issued		
Common Stock, $.01 par value, 100,000,000 shares authorized and 28,665,620 shares issued and outstanding at June 30, 2005 and 50,000,000 shares authorized and 28,380,207 shares outstanding at December 31, 2004	287	284
Additional paid-in capital	287,176	273,002
Unearned compensation	(4,215)	(2,537)
Retained earnings	635,466	558,198
Accumulated other comprehensive (loss)	(146,149)	(46,027)
Total Stockholders Equity	772,565	782,920
Total Liabilities and Stockholders Equity	$1,865,182	$1,722,577

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)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
Revenues:				
Natural gas and oil revenues	$175,524	$172,578	$341,014	$324,212
Other	293	198	523	446
Total revenues	175,817	172,776	341,537	324,658
Operating expenses:				
Lease operating	19,124	12,499	34,492	25,205
Severance tax	4,530	3,891	7,464	6,948
Transportation expense	2,993	3,169	5,759	5,905
Asset retirement accretion expense	1,326	1,190	2,651	2,478
Depreciation, depletion and amortization	71,944	67,192	142,547	128,156
General and administrative, net of amounts capitalized	6,200	9,761	17,323	15,849
Total operating expenses	106,117	97,702	210,236	184,541
Income from operations	69,700	75,074	131,301	140,117
Other (income) expense	(1,067)	(378)	387	(268)
Interest expense, net of amounts capitalized.	3,196	2,306	6,630	4,593
Income before income taxes	67,571	73,146	124,284	135,792
Provision for taxes	23,741	27,796	47,016	50,752
Net income	$ 43,830	$ 45,350	$ 77,268	$ 85,040
Earnings per share:				
Net income per share basic	$ 1.53	$ 1.49	$ 2.70	$ 2.74
Net income per share diluted	$ 1.51	$ 1.47	$ 2.67	$ 2.72
Weighted average shares outstanding basic	28,679	30,547	28,589	31,072
Weighted average shares outstanding diluted	28,973	30,810	28,920	31,262

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)
(Unaudited)

	Six Months Ended June 30, 2005	2004
Operating Activities:		
Net income	$ 77,268	$ 85,040
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	142,547	128,156
Deferred income tax expense	30,988	23,642
Asset retirement accretion expense	2,651	2,478
Stock compensation expense	2,022	1,329
Tax benefit non-qualified stock options	1,881	2,419
Loss due to ineffectiveness of derivative instruments	1,424	1,700
Amortization of premiums paid on derivative contracts		3,576
Debt extinguishment		211
Changes in operating assets and liabilities:		
Accounts receivable	1,063	(24,517)
Inventories	(663)	(46)
Prepayments and other	6,397	2,893
Other non-current assets	1,411	(2,794)
Accounts payable and accrued expenses	12,886	16,723
Other non-current liabilities	1,363	7,109
ARO liability for assets abandoned		(2,569)
Net cash provided by operating activities	281,238	245,350
Investing Activities:		
Investment in property and equipment	(278,882)	(165,436)
Dispositions and other	165	13,138
Net cash used in investing activities	(278,717)	(152,298)
Financing Activities:		
Proceeds from long-term borrowings	207,000	184,000
Repayments of long-term borrowings	(232,000)	(201,000)
Debt issue costs		(1,555)
Proceeds from issuance of common stock from exercise of stock options	8,596	16,455
Proceeds from issuance of common stock		310,567
Repurchase of common stock		(388,979)
Net cash used in financing activities	(16,404)	(80,512)
(Decrease) Increase in cash and cash equivalents	(13,883)	12,540
Cash and cash equivalents, beginning of period	18,577	2,569

Cash and cash equivalents, end of period	$ 4,694	$ 15,109
Supplemental Information:		
Non-cash transactions:		
Divesture and exchange of Appalachian Basin assets	$	$ 60,000
Cash paid during period for:		
Interest	$ 10,494	$ 7,817
Federal and state income taxes	10,860	16,900

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 producer concentrating on growing reserves and production through the exploration, development, exploitation and acquisition of natural gas and oil reserves in North America. Our core areas of operations are South Texas, offshore in the shallow waters of the Gulf of Mexico, the Arkoma Basin of Oklahoma and Arkansas and the Rocky Mountain region where, during 2003, we began operations with an initial focus in the Uinta Basin of northeastern Utah and during 2004, we expanded our focus to the DJ Basin in Eastern Colorado.

We were founded in December 1985 as a Delaware corporation and began exploring for natural gas and oil on behalf of KeySpan Corporation, our then parent company. KeySpan, a member of the Standard & Poor s 500 Index, is a diversified energy provider whose principal natural gas distribution and electric generation operations are located in the Northeastern United States. In September 1996, we completed our initial public offering and sold approximately 31% of our shares to the public. Through a series of three separate transactions, the first in February 2003 and the last in November 2004, KeySpan completely divested of its interest in the common stock of our company.

Principles of Consolidation

Our consolidated financial statements for the period ended June 30, 2005, include our accounts and the accounts of our wholly-owned subsidiaries. All significant inter-company balances and transactions have been eliminated.

Our consolidated financial statements for the period ended June 30, 2004, include our accounts and the accounts of Seneca-Upshur Petroleum, Inc., which was our wholly-owned subsidiary until June 2, 2004, when we conveyed all of the shares of Seneca-Upshur to KeySpan in connection with an asset exchange transaction. At that time, Seneca-Upshur was our only subsidiary. Seneca-Upshur is a natural gas exploration and production company located in West Virginia. All significant inter-company balances and transactions were eliminated.

Interim Financial Statements

Our balance sheet at June 30, 2005, 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. Our balance sheet at December 31, 2004, is derived from our December 31, 2004 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, 2004.

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, our unevaluated properties and our full cost ceiling test. In addition, estimates are used in computing taxes, preparing accruals of operating costs and production revenues, asset retirement obligations, fair value and effectiveness of derivative instruments and fair value of stock options and the related compensation expense. Because there are numerous uncertainties inherent in the estimation process, actual results could differ materially from these estimates.

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THE HOUSTON EXPLORATION COMPANY
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(Unaudited)

Business Segment Information

The Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) 131, Disclosures about Segments of an Enterprise and Related Information, establishes standards for reporting information about operating segments. Operating segments are defined as components of an enterprise that engages in activities from which it may earn revenues and incur expenses, separate financial information is available and this information is regularly evaluated by the chief decision maker for the purpose of allocating resources and assessing performance. Segment reporting is not applicable for us as each of our operating areas has similar economic characteristics and each meets the criteria for aggregation as defined in SFAS 131. All of our operations involve the exploration, development and production of natural gas and oil, and all of our operations are located in the United States. We have a single, company-wide management team that administers all properties as a whole rather than as discrete operating segments. We track only basic operational data by area, and do not maintain separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis. Throughout the year, we freely allocate capital resources on a project-by-project basis across our entire asset base to maximize profitability without regard to individual areas or segments.

Revenue Recognition and Gas Imbalances

We use the entitlements method of accounting for the recognition of natural gas and oil revenues. Under this method of accounting, income is recorded based on our net revenue interest in production or nominated deliveries. We incur production gas volume imbalances in the ordinary course of business. Net deliveries in excess of entitled amounts are recorded as liabilities, while net under deliveries are reflected as assets. Imbalances are reduced either by subsequent recoupment of over-and-under deliveries or by cash settlement, as required by applicable contracts. Production imbalances are marked-to-market at the end of each month at the lowest of (i) the price in effect at the time of production; (ii) the current market price; or (iii) the contract price, if a contract is in hand.

At June 30, 2005, we had production imbalances representing assets of $3.8 million and liabilities of $4.8 million. At December 31, 2004, we had production imbalances representing assets of $3.3 million and liabilities of $4.0 million. The primary sources of our production imbalances relate to Eugene Island 331, acquired in October 2003 from Transworld Exploration and Production Inc., and to various Arkoma wells. Production imbalances are included in the line items other non-current assets and other non-current liabilities on the balance sheet.

Net Income Per Share

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

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2005	**2004**	**2005**	**2004**
	(in thousands, except per share data)			
Numerator:				
Net income	$43,830	$45,350	$77,268	$85,040
Denominator:				
Weighted average shares outstanding	28,679	30,547	28,589	31,072
Add dilutive securities: Stock options	294	263	331	190

Total weighted average shares outstanding and dilutive securities	28,973	30,810	28,920	31,262
Earnings per share basic:	$ 1.53	$ 1.49	$ 2.70	$ 2.74
Earnings per share diluted:	$ 1.51	$ 1.47	$ 2.67	$ 2.72

For the three months ended June 30, 2005 and 2004, the calculation of shares outstanding for diluted earnings per share does not include the effect of outstanding stock options to purchase 393,370 and 739,444 shares, respectively, because the exercise price of these shares was greater than the average market price for the year, which would have an antidulitive

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(Unaudited)

effect on earnings per share. For the six months ended June 30, 2005 and 2004, the calculation of shares outstanding for diluted earnings per share does not include the effect of outstanding stock options to purchase 387,678 and 1,156,348 shares, respectively, because the exercise price of these shares was greater than the average market price for the year, which would have an antidulitive effect on earnings per share.

Comprehensive Income (Loss)

Comprehensive income includes net income and certain items recorded directly to stockholders equity and classified as other comprehensive income. The table below summarizes comprehensive income and provides the components of the change in accumulated other comprehensive income for the three-month and six-month periods ended June 30, 2005 and 2004.

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2005	**2004**	**2005**	**2004**
	(in thousands)			
Net income	$43,830	$ 45,350	$ 77,268	$ 85,040
Other comprehensive income (loss)				
Derivative instruments settled and reclassified, net of tax	15,720	8,560	24,877	16,020
Change in unrealized (loss) fair value of open derivative contracts, net of tax	11,860	(22,213)	(124,999)	(57,782)
Total other comprehensive income (loss)	27,580	(13,653)	(100,122)	(41,762)
Comprehensive income (loss)	$71,410	$ 31,697	$ (22,854)	$ 43,278

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 (including assets associated with retirement obligations); plus,
- estimates for future development costs (excluding asset retirement obligations); 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

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flow hedge accounting under SFAS 133, Accounting for Derivative Instruments and Hedging Activities, to hedge against the volatility of natural gas prices, and in accordance with SEC guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation. In addition, subsequent to the adoption of SFAS 143, Accounting for Asset Retirement Obligations, the future cash outflows associated with settling asset retirement obligations are excluded from the computation of the discounted present value of future net revenues for the purposes of the 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 once a determination has been made or upon expiration of a lease. Costs of seismic data are allocated to various unproved leaseholds and transferred to the amortization base with the associated leasehold costs on a specific project basis. Costs associated with wells in progress and wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. Costs of dry holes are transferred to the amortization base immediately upon determination that the well is unsuccessful. All items included in our unevaluated property balance are assessed on a quarterly basis for possible impairment or reduction in value. We estimate that these costs will be evaluated within a four-year period.

Asset Retirement Obligations

For us, asset retirement obligations (ARO) represent the future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and other facilities. SFAS 143, Accounting for Asset Retirement Obligations, 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, an adjustment is made 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. We carry ARO assets on the balance sheet as part of our full cost pool, and include these ARO assets in our amortization base for the purposes of calculating depreciation, depletion and amortization expense. For the purposes of calculating the ceiling test, the future cash outflows associated with settling the ARO liability are excluded from the computation of the discounted present value of estimated future net revenues.

The following table describes changes in our ARO liability during the six-month periods ended June 30, 2005 and 2004. The ARO liability in the table below includes amounts classified as both current and long-term at period end.

	Six Months Ended June 30,	
	2005	**2004**
	(in thousands)	
ARO liability at January 1	$91,746	$ 92,357
Accretion expense	2,651	2,478
Liabilities incurred from drilling	2,530	3,281
Liabilities incurred from assets acquired	169	-
Liabilities settled assets sold	(32)	(12,714)
Liabilities settled assets abandoned	(870)	(3,957)
Changes in estimates	798	-
ARO liability at June 30	$96,992	$ 81,445

Derivative Instruments and Hedging Activities

Our hedging policy does not permit us to hold derivative instruments for trading purposes and mandates that all hedge structures meet the definition of cash flow hedges to qualify for hedge accounting under SFAS 133, Accounting for Derivative Instruments and Hedging Activities, as amended, and that all hedge transactions are specifically identified as hedges for Federal income tax purposes as defined in Section 1221(b)(2) of the Internal Revenue Code. Our hedging policy allows us the flexibility to implement a wide variety of hedging strategies , including swaps, collars and options. We generally execute contracts with significant, credit-worthy financial institutions and to a lesser extent, other 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

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THE HOUSTON EXPLORATION COMPANY
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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 qualify for hedge accounting and, we carry the fair market value of our derivative instruments on the balance sheet as either an asset or liability and defer unrealized gains or losses in accumulated other comprehensive income. Gains and losses are reclassified from accumulated other comprehensive income to the income statement as a component of natural gas and oil revenues in the period the hedged production occurs. If any ineffectiveness occurs, amounts are recorded directly to the income statement and would be included as a component of the line item natural gas and oil revenues. For us, ineffectiveness is primarily 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, 2005, we recorded an unrealized loss in accumulated other comprehensive income of $146.1 million, net of tax, representing the fair value of our open derivative contracts. Any loss will be realized in future earnings at the time of the related sales of natural gas production applicable to specific hedges. If prices in effect at June 30, 2005, were to remain unchanged, over the next 12-month period, we would expect to reclassify from accumulated other comprehensive income to earnings a loss of $89.2 million, net of tax, relating to our open derivative contracts. However, these amounts could vary materially as a result of changes in market conditions.

We structure the language contained in our hedge agreements in such a manner that a margin call would not be required unless there is a significant event that would cause our credit rating to be downgraded. In most cases, if a margin call were required and the counterparty is and continues to be a member of our bank lending group, there would be no margin requirement for us. In limited instances, we could be required to post a letter of credit to further guarantee our performance if the fair value of an open contract or contracts exceeds our available credit limit with a particular counterparty. As of June 30, 2005, we had no outstanding letters of credit relating to derivative contracts.

Accounting for Stock Options and Restricted Stock

On January 1, 2003, we adopted the fair value expense recognition provisions of SFAS 123, Accounting for Stock-Based Compensation, as amended by SFAS 148, Accounting for Stock Based Compensation Transition and Disclosure using the prospective method as defined by the SFAS 148. As a result, we recorded as compensation expense the fair value of all stock options issued subsequent to January 1, 2003. No expense for stock options has been recorded for grants made in years prior to January 1, 2003. Prior to 2003, we accounted for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board (APB) Opinion 25, Accounting for Stock Issued to Employees, and related interpretations. Accordingly, compensation cost for stock options was measured as the excess, if any, of the fair value of common stock at the date of the grant over the amount the employee must pay to acquire the common stock. If the exercise price of a stock option was equal to the fair market value at the time of grant, no compensation expense was incurred. If we had accounted for all stock options 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 months and six months ended June 30, 2005 and 2004.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(in thousands, except share data)			
Net income as reported	$43,830	$45,350	$77,268	$85,040
Add: Stock-based compensation expense included in net income, net of tax	428	424	874	655
Less: Stock-based compensation expense determined using fair value method, net of tax	(785)	(1,466)	(1,586)	(2,733)
Net income pro forma	$43,473	$44,308	$76,556	$82,962
Net income per share basic as reported	$ 1.53	$ 1.49	$ 2.70	$ 2.74
Net income per share diluted as reported	1.51	1.47	2.67	2.72
Net income per share basic pro forma	$ 1.52	$ 1.45	$ 2.68	$ 2.67
Net income per share diluted pro forma	1.50	1.44	2.65	2.65

The effects of applying SFAS 123 in this pro forma disclosure may not be representative of future amounts.

The weighted average fair value of options at their grant date for the first six months of 2005 and 2004 were $20.89 and $14.95, respectively. The fair value of each option grant was estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions used for grants during the six months ended June 30, 2005 and 2004:

	Six Months Ended June 30,	
	2005	2004
Risk-free interest rate.	4.0%	3.9%
Expected years until exercise	5	5
Expected stock volatility	34.7%	37.1%
Expected dividends		

For the risk-free interest rate, we utilize daily rates for five-year United States treasury bills with constant maturity. The expected life is based on historical exercise activity over the previous nine-year period. The expected volatility is based on historical volatility and measured using the average closing price of our stock over a 60-month period. We believe historical volatility is the most accurate measure of future volatility of our common stock.

The following table provides the detail of stock compensation expenses incurred during each of the three-month and six-month periods ended June 30, 2005 and 2004:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(in thousands)			
Options	$ 766	$ 449	$1,583	$ 904
Restricted stock	244	363	439	425

Stock compensation expense, gross	1,010	812	2,022	1,329
Amounts capitalized	(347)	(159)	(669)	(322)
Stock compensation expense, net	$ 663	$ 653	$1,353	$1,007

Recent Accounting Pronouncements

On May 30, 2005, the FASB issued SFAS 154, Accounting Changes and Error Corrections. SFAS 154 changes the requirements for the accounting and reporting of a change in accounting principle, including voluntary changes in accounting principle as well as to changes required by an accounting pronouncement that does not include specific transition provisions. In accordance with the new standard, changes in accounting principles are retrospectively applied to all prior period financial statements presented and the cumulative effect of the change is reflected in opening retained earnings. If impracticable to determine either the period-specific effects or the cumulative effect of the change, the new accounting principle would be applied as if it were adopted prospectively from the earliest date practicable. A change in accounting estimate continues to be accounted for in the period of the change in estimate or prospectively. The correction

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of errors in previously issued financial statements should be termed a restatement. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005, or January 1, 2006, for our company.

On December 16, 2004, the FASB revised Statement 123 (revised 2004), Share-Based Payment that will require compensation costs related to share-based payment transactions (e.g., issuance of stock options and restricted stock) to be recognized in the financial statements. With limited exceptions, the amount of compensation cost will be measured based on the grant date fair value of the equity or liability instruments issued. In addition, liability awards will be remeasured each reporting period. Compensation cost will be recognized over the period that an employee provides service in exchange for the award. Statement 123(R) replaces SFAS 123, Accounting for Stock-Based Compensation, and supersedes Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees. For us, SFAS 123(R), as amended by SEC Release 34-51558, is effective for our first fiscal year beginning after June 15, 2005, or January 1, 2006. Entities that use the fair-value-based method for either recognition or disclosure under SFAS 123 are required to apply SFAS 123(R) using a modified version of prospective application. Under this method, an entity records compensation expense for all awards it grants after the date of adoption. In addition, the entity is required to record compensation expense for the unvested portion of previously granted awards that remain outstanding at the date of adoption. In addition, entities may elect to adopt SFAS 123(R) using a modified retrospective method whereby previously issued financial statements are restated based on the expense previously calculated and reported in their pro forma footnote disclosures.

On January 1, 2003, we adopted the fair value expense recognition provisions of SFAS 123 as amended by SFAS 148, Accounting for Stock-Based Compensation Transition and Disclosure using the prospective method as defined by the SFAS 148. As a result, we have recognized compensation expense for all stock options granted subsequent to January 1, 2003, with no expense recognized for grants made prior to 2003. Adoption of SFAS 123(R) will require us to recognize compensation expense over the remaining service period for the unvested portion of all options granted during 2000, 2001 and 2002. All options granted prior to 2000 are fully vested. We expect to adopt SFAS 123(R) on January 1, 2006, using the modified version of the prospective application. We are currently evaluating the effect adopting SFAS 123(R) will have to our financial statements.

On March 29, 2005, the SEC released Staff Accounting Bulletin (SAB) 107 providing additional guidance in applying the provisions of SFAS 123(R), Share-Based Payment. SAB 107 should be applied when adopting SFAS 123(R) and addresses a wide range of issues, focusing on valuation methodologies and the selection of assumptions. In addition, SAB 107 addresses the interaction of SFAS 123(R) with existing SEC guidance.

NOTE 2 Long-Term Debt and Notes

	June 30, 2005	December 31, 2004
	(in thousands)	
Senior Debt:		
Revolving bank credit facility, due April 1, 2008	$155,000	$ 180,000
Subordinated Debt:		
7% senior subordinated notes, due June 15, 2013	175,000	175,000
Total long-term debt and notes	$330,000	$ 355,000

The carrying amount of borrowings outstanding under our revolving bank credit facility approximates fair value as the interest rates are tied to current market rates. At June 30, 2005, the quoted market value of our $175 million of 7% senior subordinated notes was 98% of the $175 million carrying value, or $171.5 million. At December 31, 2004, the quoted market value of our $175 million of 7% senior subordinated notes was 101% of the $175 million carrying value, or $177 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 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. Our current borrowing base is $400

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million, which is expected to remain in effect until the next scheduled redetermination on October 1, 2005. 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 7% senior subordinated notes. The facility matures on April 1, 2008. At June 30, 2005, we had $155 million in outstanding borrowings under the credit facility and $0.4 million in outstanding letter of credit obligations.

Interest is payable on borrowings under our revolving bank credit facility, as follows:

- on base rate loans, at a fluctuating rate, or base rate, equal to the sum of (a) the greater of the Federal funds rate plus 0.5% or Wachovia s prime rate plus (b) a variable margin between 0.00% 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. Our subsidiaries are guarantors under the credit facility, and we are restricted and limited in our ability to pay cash dividends, to purchase or redeem our stock and to sell or encumber our assets. Financial covenants require us to, among other things:

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

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

- not hedge more than 85% of our production during any calendar year.

At June 30, 2005, and December 31, 2004, 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;

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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 subsidiaries to make certain distributions or payments; or

guarantees by our subsidiaries of certain indebtedness.

In addition, upon the occurrence of a change of control (as defined in the indenture), 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.

NOTE 3 Stockholders Equity

Increase in Number of Shares Outstanding

At our annual meeting of stockholders on April 26, 2005, our Board of Directors received shareholder approval to increase the number of shares we are authorized to issue to up to 105,000,000 shares of stock, including up to 100,000,000 shares of common stock and up to 5,000,000 shares of preferred stock. An amendment to our Restated Certificate of Incorporation was filed with the Secretary of State of the State of Delaware on April 26, 2005 to reflect the increase.

NOTE 4 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.

Operating Leases

We have entered into non-cancelable operating lease agreements in the ordinary course of our business activities. These leases include those for our office space at 1100 Louisiana Street in Houston, Texas, and at 700 17th Street in Denver, Colorado, together with various types of office equipment (telephones, copiers and faxes). The terms of these agreements have various expiration dates from 2005 through 2009. Future minimum lease payments for the remainder of 2005 and each of the subsequent four years from 2006 through 2009 are $0.8 million, $1.5 million, $1.6 million, $1.6 million and $0.9 million, respectively.

Purchase Obligations

We have committed to acquire additional offshore seismic data under an existing license agreement for up to $7.7 million which is payable in January 2006.

Letters of Credit

We had $0.4 million of letters of credit outstanding at June 30, 2005, and December 31, 2004. These letters of credit were issued for natural gas and oil operating activities, none of which were collateralized.

Drilling Contract

In February 2005, we entered into a one-year contract for the use of a drilling rig in the Uinta Basin. Under the terms of the contract, we are obligated for up to an estimated $2.5 million in fees for use of the rig during the remaining portion of the one-year term.

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NOTE 5 Related Party Transactions

Employment Agreements

On February 8, 2005, with the approval of our Board of Directors, we entered into amended and restated employment agreements with five senior executives officers, including our President and Chief Executive Officer. Each agreement is for a term of three years, with automatic one-year extensions thereafter unless the executive or we provide notice of termination at least 90 days prior to the end of the applicable term.

By entering into the amended and restated employment agreements and terminating their prior employment agreements with us, the senior executive officers gave up certain rights, including the right to receive severance for a termination of employment following a change of control of our company absent the existence of good reason and the right to guaranteed annual stock option grants and incentive compensation bonuses which will now be subject to the discretion of our Compensation and Management Development Committee. In addition to these rights, our President and Chief Executive Officer gave up the right to receive a transaction bonus upon the occurrence of certain corporate transactions involving our company, and all of the executives have agreed to broader non-competition provisions under the amended and restated agreements.

In consideration for entering into the amended and restated agreements and foregoing such rights, in February 2005, we paid these senior executive officers an aggregate of $5.1 million in cash and issued a total of 30,105 shares of restricted stock. The restricted stock vests over a period of five years in accordance with the terms of our 2004 Long-Term Incentive Compensation Plan.

All of the employment agreements provide that if we terminate an executive s agreement without cause (as defined in the employment agreement), or if the executive terminates his or her employment with us for good reason (as defined in the agreement, which includes the occurrence of certain events following a change in control of our company), we are obligated to pay the executive a lump-sum severance payment equal to 2.99 times his or her then current annual rate of total compensation and to continue certain welfare benefits. The agreements further provide that if any payments made to the executives, whether or not under the agreement, would result in an excise tax being imposed on the executives under Section 4999 of the Internal Revenue Code; we will make each of the executives whole on a net after-tax basis.

We may terminate any employment agreement for cause or upon the death or disability of the executive without financial obligation (other than payment of any accrued obligations). Each executive may terminate his or her employment agreement at any time for any reason upon at least 30 days prior written notice. In the event the executive s employment is terminated by us without cause or upon death or disability, or if the executive terminates his or her employment with us for good reason, any unvested shares of restricted stock, unvested options or similar deferred compensation automatically will vest and any other conditions to such awards shall be deemed satisfied.

As a result of the amended and restated employment agreements, we incurred approximately $5.3 million in additional compensation expense during the first six months of 2005. The additional expense includes the cash payments made during the first quarter of 2005 together with the compensation expense incurred for the amortization of the restricted stock during the first six months of 2005.

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NOTE 6 Acquisitions

East Texas Acquisitions

On March 15, 2005, we completed the purchase of certain natural gas and oil producing properties and associated gathering pipelines and equipment, together with developed and undeveloped acreage, located in the Rusk County, Texas, from Dale Gas Partners, L.P. The $22.0 million purchase price was paid in cash and financed by borrowings under our revolving bank credit facility. The properties purchased cover approximately 5,776 gross acres located in South Oak Hill Field, which is in close proximity to our existing operations in the Willow Springs Field, and represents interests in three producing wells and one well in the completion stage. We operate all of the wells acquired and our working interest is 100%. Total proved reserves associated with the interests acquired were 9.1 Bcfe as of March 15, 2005, the effective date of the transaction.

On April 5, 2005, we completed the acquisition of a 50% working interest in seven producing wells together with undeveloped acreage located in the North Blocker Field located in Harrison County, Texas from Dale Resources East Texas L.L.C. The $9.2 million purchase price was paid in cash and financed by borrowings under our revolving bank credit facility. The properties purchased cover approximately 4,679 gross acres and, we operate all seven wells. Total proved reserves associated with the interests acquired are estimated at 7.7 Bcfe, as of April 1, 2005, the effective date of the transaction.

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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, 2004.

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 and Other Information at the beginning of this Quarterly Report and Risk Factors Affecting Our Business beginning on page 15 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 producer concentrating on growing reserves and production through the exploration, development, exploitation and acquisition of natural gas and oil reserves in North America. Our core 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 initiated operations in the Rocky Mountain Region, with an initial focus in the Uinta Basin of northeastern Utah, and during 2004, we expanded our focus to include the DJ Basin of Eastern Colorado. We operate as one segment as each of our operating areas has similar economic characteristics and each meets the criteria for aggregation as defined in the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) 131, Disclosures about Segments of an Enterprise and Related Information. At December 31, 2004, net proved reserves were 793 billion cubic feet equivalent, or Bcfe, with a standardized measure of future net cash flows including income taxes, discounted at 10% per annum, of $1.4 billion. Our reserves are fully engineered on an annual basis by independent petroleum engineers. Approximately 94% of our proved reserves at December 31, 2004, were natural gas, approximately 63% of which were classified as proved developed. As of December 31, 2004, we operated approximately 77% of our producing wells. Daily production averaged 339 million cubic feet of natural gas equivalent or MMcfe in 2004.

We were founded in December 1985 as a Delaware corporation and began exploring for natural gas and oil on behalf of KeySpan Corporation, our then parent company. KeySpan, a member of the Standard & Poor s 500 Index, is a diversified energy provider whose principal natural gas distribution and electric generation operations are located in the Northeastern United States. In September 1996 we completed our initial public offering and sold approximately 31% of our shares to the public. Through three separate transactions, the first in February 2003 and the last in November 2004, KeySpan completely divested of its investment in the common stock of our company.

Source of Our Revenues

We derive our revenues from the sale of natural gas and oil that is produced from our natural gas and oil properties. Revenues are a function of the volume produced and the prevailing market price at the time of sale. The price of natural gas is the primary factor affecting our revenues. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we utilize derivative instruments to hedge future sales prices on a significant portion of our natural gas production. During the first six months of both 2005 and 2004, the use of derivative instruments 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. These costs include: lease operating expense, severance tax and transportation expense, which costs are expected to increase.

Depreciation, Depletion and Amortization. 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 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 through depreciation, depletion and amortization expense. Generally, if reserve quantities are revised up or down, the depreciation, depletion and amortization rate per unit of production will change inversely.

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Asset Retirement Accretion Expense. 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 Expense. 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 general and administrative expense directly related to our acquisition, exploration and development activities.

Interest. We typically finance our working capital requirements and 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 that are not being amortized.

Income Taxes. We are subject to state and federal income taxes and are currently in a tax paying position. We expect to continue to recognize current tax expense as long as we are generating taxable income.

Critical Accounting Estimates and Significant Accounting Policies

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements requires us to make assumptions and prepare estimates that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities and revenues and expenses. We base our estimates on historical experience and various other assumptions that we believe are reasonable; however, actual results may differ. We evaluate our assumptions and estimates on a regular basis and discuss the development and disclosure process with our Audit Committee. Estimates of proved reserves are key components of our most significant financial estimates involving unevaluated properties, depreciation, depletion and amortization and our full cost ceiling limitation. In addition, estimates are used to accrue production revenues and operating expenses, drilling costs, federal and state taxes, the fair value of derivative contracts, including the calculation of ineffectiveness and the fair value of our stock options. There has been no change in our critical accounting policies and use of estimates since our most recent Annual Report for the year ended December 31, 2004.

Recent Accounting Pronouncements

On May 30, 2005, the FASB issued SFAS 154, Accounting Changes and Error Corrections. SFAS 154 changes the requirements for the accounting and reporting of a change in accounting principle, including voluntary changes in accounting principle as well as to changes required by an accounting pronouncement that does not include specific transition provisions. In accordance with the new standard, changes in accounting principles are retrospectively applied to all prior period financial statements presented and the cumulative effect of the change is reflected in opening retained earnings. If impracticable to determine either the period-specific effects or the cumulative effect of the change, the new accounting principle would be applied as if it were adopted prospectively from the earliest date practicable. A change in accounting estimate continues to be accounted for in the period of the change in estimate or prospectively. The correction of errors in previously issued financial statements should be termed a restatement. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005, or January 1, 2006, for our company.

On December 16, 2004, the FASB revised Statement 123 (revised 2004), Share-Based Payment that will require compensation costs related to share-based payment transactions (e.g., issuance of stock options and restricted stock) to be recognized in the financial statements. With limited exceptions, the amount of compensation cost will be measured based on the grant-date fair value of the equity or liability instruments issued. In addition, liability awards will be remeasured each reporting period. Compensation cost will be recognized over the period that an employee provides service in exchange for the award. Statement 123(R) replaces SFAS 123, Accounting for Stock-Based Compensation, and supersedes Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees. For us, SFAS 123(R), as amended by SEC Release 34-51558, is effective for our first fiscal year beginning after June 15, 2005, or January 1, 2006. Entities that use the fair-value-based method for either recognition or disclosure under SFAS 123 are required to apply SFAS 123(R) using a modified version of prospective application. Under this method, an entity records compensation expense for all awards it grants after the date of adoption. In addition, the entity is required to record compensation expense for the unvested portion of previously granted awards that remain outstanding at the date of adoption. In addition, entities may elect to adopt SFAS 123(R) using a modified retrospective method where by previously issued financial statements are restated based on the expense previously calculated and reported in their pro forma footnote disclosures.

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On January 1, 2003, we adopted the fair value expense recognition provisions of SFAS 123 as amended by SFAS 148, Accounting for Stock-Based Compensation Transition and Disclosure using the prospective method as defined by the SFAS 148. As a result, we have recognized compensation expense for all stock options granted subsequent to January 1, 2003, with no expense recognized for grants made prior to 2003. Adoption of SFAS 123(R) will require us to recognize compensation expense over the remaining service period for the unvested portion of all options granted during 2000, 2001 and 2002. All options granted prior to 2000 are fully vested. We expect to adopt SFAS 123(R) on January 1, 2006, using the modified version of the prospective application. We are currently evaluating the effect adopting SFAS 123(R) will have to our financial statements.

On March 29, 2005, the SEC released Staff Accounting Bulletin (SAB) 107 providing additional guidance in applying the provisions of SFAS 123(R), Share-Based Payment. SAB 107 should be applied when adopting SFAS 123(R) and addresses a wide range of issues, focusing on valuation methodologies and the selection of assumptions. In addition, SAB 107 addresses the interaction of SFAS 123(R) with existing SEC guidance.

Overview of Results for the Second Quarter of 2005

Strong commodity prices, a decline in average daily production and an increase in operating expenses and capital spending were the primary factors behind results for operations, earnings and cash flows during the second quarter of 2005. During the second quarter of 2005:

- We generated $43.8 million in net income, a decrease of 3% from second quarter 2004;

- We produced approximately 30 Bcfe and our average daily production rate was 328 MMcfe per day compared to a record level of 351 MMcfe per day during the second quarter of 2004. Production levels have remained nearly flat during the first half of 2005 primarily a result of delays in our offshore Gulf of Mexico development program caused by delays in rig availability combined with lower production rates in South Texas;

- We generated $132.4 million in net cash flows from operating activities compared to $116.7 million during the second quarter of 2004, an increase of 13%;

- We invested $132.2 million in natural gas and oil properties, which included $9 million for a second producing property acquisition in East Texas;

- We drilled 79 wells, of which 69, or 87%, were successful with five offshore, three in East Texas, 16 in South Texas, 16 in Arkoma and 29 in the Rockies;

- We decreased our outstanding borrowings under our revolving bank credit facility by a net $10 million;

- We successfully integrated the East Texas producing properties acquired in March and April 2005, added two drilling rigs, successfully drilled three development wells and increased average daily production in the area by approximately 2 Mcfe per day for the quarter;

- In mid-May, we successfully completed and brought on-line the sidetrack of the No. 1 well at High Island 47 which had been shut-in since the fourth quarter of 2004;

- In mid-June, drilling began on the sidetrack of the No. 1 well at High Island 115 which had been shut-in since the fourth quarter of 2004 due to a mechanical problem;

- We participated in the completion of a discovery at West Cameron 75, with two subsequent discoveries in July at West Cameron 77 and West Cameron 62. All three discoveries are located on the Outer Continental Shelf and considered deep shelf prospects; and

We completed the hook-up of 15 new wells in the DJ Basin of Eastern Colorado, with initial production from these wells beginning the third week of July 2005.

Operating and Financial Results for the Three Months Ended June 30, 2005 Compared to the Three Months Ended June 30, 2004 and the Six Months Ended June 30, 2005 Compared to the Six Months Ended June 30, 2004.

	Three Months Ended June 30,				Six Months Ended June 30,			
Summary Operating Information:	**2005**	**2004**	**Variance**		**2005**	**2004**	**Variance**	
	(in thousands, except average sales price)							
Operating revenues	$ 175,817	$ 172,776	$ 3,041	2%	$ 341,537	$ 324,658	$ 16,879	5%
Operating expenses	106,117	97,702	8,415	9%	210,236	184,541	25,695	14%
Income from operations	69,700	75,074	(5,374)	-7%	131,301	140,117	(8,816)	-6%
Net income	43,830	45,350	(1,520)	-3%	77,268	85,040	(7,772)	-9%
Production:								
Natural gas (MMcf)	27,440	30,138	(2,698)	-9%	54,797	58,270	(3,473)	-6%
Oil (MBbls)	406	304	102	34%	812	652	160	25%
Total (MMcfe) (1)	29,876	31,962	(2,086)	-7%	59,669	62,182	(2,513)	-4%
Average daily production (MMcfe/d)	328	351	(23)	-7%	330	342	(12)	-4%
Average Sales Prices:								
Natural Gas (per Mcf) realized (2)	$ 5.71	$ 5.39	$ 0.32	6%	$ 5.57	$ 5.19	$ 0.38	7%
Natural Gas (per Mcf) unhedged	6.60	5.85	0.75	13%	6.30	5.65	0.65	12%
Oil (per Bbl) realized	46.32	33.63	12.69	38%	44.24	33.02	11.22	34%

(1) Mcfe is defined as 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.

Income from Operations

Operating revenues were 2% higher during the second quarter of 2005 as compared to the second quarter 2004 primarily as a result of higher average realized prices for both natural gas and oil that more than offset a 7% quarter-over-quarter decrease in production volumes due to the unusually large number of development projects brought on-line during the second quarter of 2004 combined with divestitures of producing properties during the first half of 2004. Operating income for the second quarter of 2005 decreased by $5.3 million, or 7%, as compared to the second quarter of 2004, as a 9% increase in operating expenses during the quarter second quarter of 2005 more than

offset a 2% increase in operating revenues.
For first six months of June 2005, operating income decreased by $8.8 million, or 6%, as a result of a 14% increase in operating expenses offset in part by a 5% increase in operating revenues. Operating revenues are higher for the first six months for 2005 primarily as a result of higher realized prices for both natural gas and oil during the period as production volumes decreased by 4% from a year ago.
Production Volume
Production volumes were 7% lower during the second quarter of 2005 compared to the second quarter of 2004 and were 4% lower during the first six months of 2005 compared to the first six months of 2004. Volumes produced in 2004 reflect large quantities of high-rate, initial production from several development projects, both onshore and offshore, brought on-line during the first half of 2004. Initial production rates from several of these projects have since declined, producing at much lower rates during the first half of 2005. In addition, we divested our Appalachian Basin properties, effective June 1, 2004, which prior to disposition contributed approximately 8 Mcfe per day to our total average daily production rate.
Onshore. Daily production rates decreased 2% from an average of 191 MMcfe per day during the second quarter of 2004 to 189 MMcfe per day during the second quarter of 2005. The Arkoma Basin, East Texas and the Rockies were our onshore growth areas during the second quarter of 2005.
Quarter-over-quarter, we added 6 MMcfe per day in newly developed production in Arkoma, increasing our average daily rate by 17% from 35 MMcfe per day during the second quarter of 2004 to 41 MMcfe per day during the second quarter of 2005. In South Texas, our average daily production declined by 6 % or, 9 MMcfe per day from 148 MMcfe per day during the second quarter of 2004 to 139 MMcfe per day during the second quarter of 2005. During the second quarter of 2004, we had several new wells that produced at higher than normal initial production rates causing our average daily rates to be

higher than normal . In addition to declining rates since the second quarter of 2004, during June 2005, the Lobo pipeline was shut-in for approximately six days causing the deferral of approximately 150 MMcfe.

For the six-month period ended June 30, 2005, onshore production was nearly flat, decreasing by just 1% from 189 MMcfe per day during the first six months of 2004 to 188 MMcfe per day during the first six months of 2005. Production added from developmental drilling in Arkoma and the Rockies was offset by production declines in South Texas and from the divesture of our South Louisiana properties in February 2004 and our Appalachian Basin properties in June 2004.

Offshore. For the three months ended June 30, 2005, offshore daily production rates decreased by 13%, or 21 MMcfe per day, from an average of 160 MMcfe per day during the second quarter of 2004 to an average of 139 MMcfe per day during the second quarter of 2005. For the six months ended June 30, 2005, offshore daily production rates decreased by 7%, or 11 MMcfe per day, from an average of 153 MMcfe per day during the first six months of 2004 to an average of 142 MMcfe per day during the first six months of 2005. During the second quarter of 2004, offshore production had achieved peak rates, primarily as a result of newly developed production at High Island A283. However, production rates were sharply curtailed during the fourth quarter of 2004 with the shut-in of High Island 115 due to a mechanical problem, a depleted well at High Island 47 and initial declines in the high production rates at High Island A283. Quarter-over-quarter and period-over-period, declining rates from existing and maturing properties have outpaced production added from our September and October 2004 acquisitions and from new wells placed on-line since the end of the second quarter of 2004. In addition, because of delays in drilling rigs arriving on location, our development program for 2005 has been delayed and we expect most of our offshore production growth to occur during the second half of 2005.

Commodity Prices and Effects of Hedging

For the three months ended June 30, 2005, our average unhedged or sales price for natural gas increased by 13% from $5.85 per Mcf during the second quarter of 2004 to $6.60 per Mcf during the second quarter of 2005. Because of the increase in the market price for natural gas, our loss from hedging activities increased by $10.4 million quarter-over-quarter. Included in natural gas revenues for the second quarter of 2005 is a loss of $24.3 million from natural gas hedging activities. As a result of the loss from hedging activities, we realized an average natural gas price during the second quarter of 2005 of $5.71 per Mcf that was 87% of, or $0.89 per Mcf lower than, our average sales price. During the second quarter of 2004, we incurred a hedge loss from natural gas derivatives of $13.9 million, which includes an unrealized loss of $0.7 million recognized for ineffectiveness, resulting in an average realized price of $5.39 per Mcf that was 92% of, or $0.46 per Mcf lower than, our average sales price during the second quarter of 2004.

For the six months ended June 30, 2005, our average unhedged or sales price for natural gas increased by 12% from $5.65 per Mcf during the first six months of 2004 to $6.30 per Mcf during the first six months of 2005. Included in natural gas revenues for the first six months of 2005 is a loss of $39.9 million from natural gas hedging activities, which is $13.4 million higher than the $26.5 million loss from hedging activities incurred during the first six months of 2004. As a result of the loss from hedging activities, our realized price for natural gas for the first six months of 2005 of $5.57 was 88% of, or $0.73 per Mcf lower than, our average unhedged natural gas price of $6.30 per Mcf, which compares a realized price during the first six months of 2004 of $5.19 per Mcf that was 92% of, or $0.46 per Mcf lower than, the unhedged price of 5.65 per Mcf.

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Operating Expenses

	Three Months Ended June 30,				Six Months Ended June 30,			
Operating Expenses per Mcfe	**2005**	**2004**	**Variance**		**2005**	**2004**	**Variance**	
Lease operating expense	$ 0.64	$ 0.39	$ 0.25	64%	$ 0.58	$ 0.41	$ 0.17	41%
Severance tax	0.15	0.12	0.03	25%	0.13	0.11	0.02	18%
Transportation expense	0.10	0.10			0.10	0.09	0.01	11%
Asset retirement accretion expense	0.04	0.04			0.04	0.04		
Depreciation, depletion and amortization	2.41	2.10	0.31	15%	2.39	2.06	0.33	16%
General and administrative, net	0.21	0.31	(0.10)	-32%	0.29	0.25	0.04	16%
Total operating expenses per unit of production	$ 3.55	$ 3.06	$ 0.49	16%	$ 3.53	$ 2.96	$ 0.57	19%

Total operating expenses on an absolute dollar basis increased 9% for the second quarter of 2005 as compared to the second quarter of 2004 and 14% for the current six-month period compared to the prior six-month period, primarily as a result of higher lease operating expenses, depreciation, depletion and amortization expense and general and administrative expenses. On a unit of production basis, operating expenses increased $0.49 per Mcfe, or 16%, quarter-over-quarter and $0.57 per Mcfe, or 19%, period-over-period.

Lease Operating Expense. On an absolute dollar basis, lease operating expense increased by 53% for the second quarter of 2005 as compared to the second quarter of 2004 and by 37% for the first six months of June 2005 as compared to the first six months of 2004. The increase during the second quarter and first six months of 2005 relates primarily to increased expenses incurred in connection with the integration of the Gulf of Mexico properties acquired in September and October of 2004, as well as a general increase in service costs and the continued expansion of our operating base from the escalation of our drilling program. During 2004 we successfully drilled and completed 177 new wells and acquired 12 new blocks in the central Gulf of Mexico pursuant to the September and October Gulf of Mexico acquisitions. During the first six months of 2005, we successfully drilled and completed an additional 131 new wells and acquired seven wells in East Texas.

Severance Tax. Severance tax is a function of volume and revenues generated from onshore production. On an absolute dollar basis, severance tax increased by 16% from the second quarter of 2004 and by 7% from the first six months of 2004 primarily as a result of the respective 13% and 12% increase in the market price for natural gas during the second quarter and first six months of 2005 as compared to the corresponding three-month and six-month periods of 2004. On a unit of production basis, severance tax increased by $0.03 per Mcfe for the second quarter of 2005 and by $0.02 per Mcfe for the first six months of 2005 as a result of the increase in severance tax expense combined with the effects of a decrease in production volumes during each of the respective periods.

Depreciation, Depletion and Amortization. The increase in our depreciation, depletion and amortization expense for the three months ended June 30, 2005 and for the six-month period then ended was primarily a result of a higher depletion rate, offset in part by lower production volume during each of the respective periods. Our depletion rate for the second quarter of 2005 of $2.41 per Mcfe was 15% higher than the $2.10 per Mcfe during the second quarter of 2004. For first six-months of 2005 our depletion rate of $2.39 per Mcfe was 16% higher than our rate of $2.06 per Mcfe during the first six months of 2004. The higher depletion rate during 2005 is primarily a result of a higher finding and development costs combined with the addition of fewer new reserves during the current six-month period.

Asset Retirement Accretion Expense. ARO accretion expense was nearly unchanged at $1.3 million for the second quarter of 2005 compared to $1.2 million for the second quarter of 2004. For the six month period ended June 30, 2005, ARO accretion expense was $2.6 million compared to $2.5 million during the corresponding six months of 2004. On a per unit of production basis, ARO accretion was unchanged at $0.04 per Mcfe quarter-over-quarter and period-over-period.

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

	Absolute Dollars Three Months Ended June 30,				Unit of Production - Mcfe Three Months Ended June 30,			
General and Administrative Expense	**2005**	**2004**	**Variance**		**2005**	**2004**	**Variance**	
	(in thousands)							
Gross general and administrative expense	$ 10,516	$ 13,937	$ (3,421)	-25%	$ 0.35	$ 0.44	$ (0.09)	-20%
Operating overhead reimbursements	(525)	(576)	51	- 9%	(0.02)	(0.02)		
Capitalized general and administrative	(3,791)	(3,600)	(191)	5%	(0.12)	(0.11)	(0.01)	9%
General and administrative expense, net	$ 6,200	$ 9,761	$ (3,561)	-36%	$ 0.21	$ 0.31	$ (0.10)	-32%

For the three months ended June 30, 2005, aggregate general and administrative expenses decreased by $3.4 million, or 25%, as compared to the corresponding three months of 2004 and net general and administrative expenses decreased by $3.6 million, or 36%, during this same period. The higher aggregate and net general and administrative expense incurred during the second quarter of 2004 included approximately $4.4 million in additional compensation expenses incurred primarily as a result of special bonuses awarded to executives and other key employees who assisted in structuring and consummating the KeySpan asset exchange transaction in June 2004. Excluding these second quarter 2004 expenses, both aggregate and net general and administrative expenses would have increased during the second quarter of 2005 by approximately $1.0 million, or 10%, and $0.8 million, or 16%, respectively, primarily as a result of increases in stock compensation expense, legal and accounting expenses and engineering and consulting fees. Because we adopted SFAS 123 in January 2003, our stock compensation expense will increase each period as we continue to issue new stock options. In addition, upon our adoption of SFAS 123(R) in January 2006, we will begin to recognize compensation expense over the remaining vesting period for the unvested portion of all options granted prior to 2003. Outside professional fees were higher during the second quarter of 2005 as a result of expenses incurred in conjunction with the review of various corporate transactions. We expect aggregate general and administrative expenses to increase as our workforce keeps pace with the continued growth and expansion of our operations.

For general and administrative expense on a per-unit of production basis, the additional $4.4 million in expenses incurred during the second quarter of 2004 related to the asset exchange transaction with KeySpan resulted in a $0.14 per Mcfe increase for the second quarter of 2004. After giving effect to the additional expense during the second quarter of 2004, gross general and administrative expense of $0.35 per Mcfe during the second quarter of 2005 would reflect a $0.05 per Mcfe, or 17% increase over second quarter of 2004 of $0.30 per Mcfe. Net general and administrative expense would reflect a $0.04 per Mcfe, or 24% increase from $0.17 per Mcfe during the second quarter of 2004 to $0.21 per Mcfe during the second quarter of 2005. The increase in both aggregate and net general and administrative expense per Mcfe is a result of a 10% increase in aggregate expenses combined with a 7% decrease in production volume during the second quarter of 2005.

	Absolute Dollars Six Months Ended June 30,				Unit of Production - Mcfe Six Months Ended June 30,			
General and Administrative Expense	**2005**	**2004**	**Variance**		**2005**	**2004**	**Variance**	
	(in thousands)							
Gross general and administrative expense	$ 26,478	$ 24,740	$ 1,738	7%	$ 0.44	$ 0.40	$ 0.04	10%
Operating overhead reimbursements	(1,075)	(1,089)	14	-1%	(0.02)	(0.02)		
Capitalized general and administrative	(8,080)	(7,802)	(278)	4%	(0.13)	(0.13)		

General and administrative expense, net	$ 17,323	$ 15,849	$ 1,474	9%	$ 0.29	$ 0.25	$ 0.04	16%

For the first six months of 2005, aggregate general and administrative expenses increased by 7%, or $1.7 million, as compared to the first six months of 2004. Net general and administrative expenses increased by 9%, or $1.5 million, during this period. During the first quarter of 2005, we incurred $5.0 million in additional expense pursuant to the February 2005 renegotiation of executive employment agreements (see Note 5 Related Party Transactions *Employment Agreements*) and during the second quarter of 2004, we incurred $4.4 million in additional expense for special bonuses paid to executives and other key employees in connection with the June 2004 asset exchange transaction with KeySpan. The remaining portion of the increase in both aggregate and net general and administrative expense for the period is a result of higher outside professional fees combined with an increase in stock compensation expense.

On a per unit of production basis, both aggregate and net general and administrative expense increased by $0.04 per Mcfe for the six month period. The increase in both aggregate and net general and administrative expense per Mcfe is a result of a 7% increase in aggregate expense combined with the effect of a 6% decrease in production volume during the first six months of 2005.

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Other Income and Expense, Interest and Taxes

Other Income and Expense. For the second quarter of 2005, other income and expense is comprised of income of $1.1 million related to refunds of prior years severance tax expense. For the first six months of 2005, other income and expense includes (i) income of $2.4 million related to refunds of prior years severance tax expense and (ii) expense of $2.8 million incurred as a result of a payout settlement at East Cameron 82/83 during the first quarter of 2005, whereby our working interest in the A3 well was subsequently reduced from 50% to 35%. 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.

Interest Expense, Net of Capitalized Interest.

Interest and Average Borrowings	Three Months Ended June 30, 2005	2004	Variance		Six Months Ended June 30, 2005	2004	Variance	
	(dollars in thousands)							
Gross interest	$ 5,621	$ 4,381	$ 1,240	28%	$ 11,045	$ 8,609	$ 2,436	28%
Capitalized interest	(2,425)	(2,075)	(350)	17%	(4,415)	(4,016)	(399)	10%
Interest expense, net of capitalized interest	$ 3,196	$ 2,306	$ 890	39%	$ 6,630	$ 4,593	$ 2,037	44%
Average borrowings [(1)]	$ 345,956	$ 263,176	$ 82,780	31%	$ 345,354	$ 272,304	$ 73,050	27%
Average interest rate [(1)]	6.04%	5.81%	0.23%	4%	5.94%	5.70%	0.24%	4%
Average bank borrowings	$ 170,956	$ 122,791	$ 48,165	39%	$ 170,354	$ 114,612	$ 55,742	49%
Average bank interest rate	5.13%	3.32%	1.81%	55%	4.88%	3.30%	1.58%	48%

(1) Average borrowings and average interest rate includes our $175 million senior notes at 7% due June 2013 and average borrowings under our revolving bank credit facility.

For both the three-month and six-month periods ended June 30, 2005, the increase in gross interest expense is due to an increase in outstanding borrowings under our revolving bank credit facility combined with an increase in average interest rates associated with our bank debt. Our average bank debt has continued to increase from the second half of 2004 through the first half of 2005 as we utilized our revolving facility to fund a portion of the asset exchange transaction with KeySpan in June 2004, two producing property acquisitions in September and October 2004 and the East Texas acquisitions in March and April 2005. Although the majority of our bank debt bears interest at LIBOR-based rates, we do expect to see an increase in rates during 2005 if the Federal Reserve continues its expected plan to slowly increase Federal interest rates. Federal rates were increased in February, March and May 2005, with a subsequent increase in July, by one quarter of a percent each time. Capitalized interest is a function of unevaluated properties and the 17% increase for the second quarter of 2005 as well as the 10% increase during the first six months of 2005 as compared to the corresponding periods of 2004, correlates with the increase in our average unevaluated property balance during the first half of 2005. The increase in unevaluated properties is due in part to timing of projects in progress and to the expansion of our drilling program during the first six months of 2005.

Income Tax Provision. Our provision for taxes includes both state and federal taxes. Our current provision for the first six months of 2005 includes $1.4 million relating to nondeductible excess executive compensation expense incurred as a result of the contract renegotiation payment made to our Chief Executive Officer in February 2005 (see Note 5 Related Party Transactions *Employment Agreements*). In addition, the provision for the first six months of 2005 includes additional expense of $2.0 million, primarily related to adjustments to estimates for federal and state liabilities incurred during the first quarter of 2005.

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 and any amounts owing in the period relating to our hedging positions. 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;

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Costs of acquiring additional reserves;

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.

On April 26, 2005, our Board of Directors increased our capital expenditure budget for 2005 from an initial level of $446 million to $512 million. The $66 million increase was made in part to accommodate our $31.3 million East Texas acquisitions made in March and April 2005. As of June 30, 2005, we had spent $278.9 million or 54% of our capital budget for 2005. To maintain flexibility of our capital program, we typically do not enter into material long-term obligations with any of our drilling contractors or service providers with respect to our operated properties; however, we may choose to do so if an opportunity is economically beneficial. Going forward, we have not included property acquisition costs in our capital budget because the size and timing of capital requirements for acquisitions are inherently unpredictable. As the year progresses, we will continue to evaluate our capital spending. Actual levels may vary due to a variety of factors, including service costs, drilling results, natural gas prices, economic conditions and future acquisitions.

Future Commitments

As of June 30, 2005, we have a purchase obligation under an existing seismic license agreement to acquire additional seismic data for up to $7.7 million payable in January 2006 and we are obligated for up to $2.5 million under a one-year contract for a drilling rig in the Uinta Basin, which expires in February 2006. Our commitment under the drilling contract is reduced each month as the rig is utilized. As of June 30, 2005, we do not have any capital leases nor have we entered into any additional long-term contracts for drilling rigs or equipment. 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, 2005. In addition to the contractual obligations listed on the table below, our balance sheet at June 30, 2005, reflects accrued interest payable on our bank credit facility of approximately $50,000 which is payable over the next 90-day period. We expect to make annual interest payments of $12.3 million per year on our $175 million of 7% senior subordinated notes due June 2013, and we anticipate making income tax payments of approximately $32 million during the remaining portion of 2005.

			As of June 30, 2005 Payments Due by Period (in thousands)			
	Reference	Total	1 year or less	2 3 years	4 5 years	after 5 years
Contractual Obligations:						
Revolving bank credit facility, due April 2008	Note 2	$ 155,000	$	$	$ 155,000	$
7% senior subordinated notes, due June 2013	Note 2	175,000				175,000
Derivative instruments	Note 1	231,560	141,331	84,113	6,116	
Operating leases	Note 4	6,477	1,540	3,189	1,748	
Seismic data purchase	Note 4	7,749	7,749			

Drilling contract	Note 4	2,531	2,531			
		578,317	153,151	87,302	162,864	175,000
Other Long-Term Obligations:						
Asset retirement obligations	Note 1	96,992	1,486	11,593	6,967	76,946
Total contractual obligations and commitments		$ 675,309	$ 154,637	$ 98,895	$ 169,831	$ 251,946

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 a significant acquisition opportunity arises, we may also access public markets for debt or to issue additional equity securities. Our primary sources of cash during the first six months of 2005 were from funds generated from operations. Cash was used to fund acquisitions, exploration and development expenditures and to reduce debt under our revolving bank credit facility. We made aggregate cash payments of $10.5 million for interest during the first six months of 2005 and $10.9 million for federal or state income taxes during the same six-month period. The table below summarizes the sources of cash for the first six months of 2005 and 2004.

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	Six Months Ended June 30,			
	2005	2004	variance	% change
	(in thousands)			
Net cash provided by operating activities	$ 281,238	$ 245,350	$ 35,888	15%
Net cash (used) for investments in property and equipment	(278,717)	(152,298)	(126,419)	83%
Net cash (used in) provided by financing activities	(16,404)	(80,512)	64,108	-80%
Net change in cash	$ (13,883)	$ 12,540	$ (26,423)	-211%

At June 30, 2005, we had a working capital deficit of $113.6 million, long-term debt of $330 million and $244.6 million of borrowing capacity available under our revolving bank credit facility. The working capital deficit at June 30, 2005, was due to a current liability of $141.3 million representing the fair value of our derivative instruments estimated to be payable over the next 12 months, offset in part by the associated deferred tax asset of $50.0 million. As a result of the sustained high level of natural gas prices, the fair value of our open derivative contracts payable within the next 12 months increased by $73.2 million from a liability of $68.1 million at December 31, 2004, to a liability of $141.3 million at June 30, 2005. Corresponding to the increase in the liability, the associated deferred tax asset increased by $25.9 million during this same six-month period. 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, which we believe is typical of companies of our size in the exploration and production industry.

Operating Activities. Net cash provided by operating activities increased by $35.9 million during the first six months of 2005. The increase was primarily a result of higher commodity prices realized during the current six-month period. In addition to fluctuations in operating assets and liabilities that are caused by timing of cash receipts and disbursements, commodity prices, production volume and operating expenses are the key factors driving changes in operating cash flows.

Investing Activities. Total capital expenditures during the first six months of 2005 were $278.9 million. We invested $278.4 million in natural gas and oil properties, which included $31.6 million for producing property acquisitions, and we spent $0.5 million for non-oil and gas property and equipment. Non-oil and gas property and equipment includes expenditures to upgrade our information technology systems and office equipment and compares to $0.7 million spent during the first six months of 2004. For the first six months of 2005, we spent 38% offshore and 57% onshore with the balance of 5% on capitalized interest and general and administrative costs. We completed the drilling of 159 gross wells (136.2 net), of which 82%, or 130 (109.7 net), were successful and 18%, or 29 (26.5 net), were unsuccessful, with an additional 12 wells (8.1 net) in progress at June 30, 2005. During the corresponding six months of 2004, we drilled 99 gross wells (81.4 net) of which 85% or 84 (69.2 net) were successful, with an additional 9 wells (7.1 net) in progress at June 30, 2004. The following table provides a summary of our capital expenditures for natural gas and oil properties during the three-month and six-month periods ended June 30, 2005 and 2004.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(in thousands)			
Producing property acquisitions	$ 9,017	$	$ 31,632	$ 2,700
Leasehold and lease acquisition costs [1]	10,338	13,006	35,574	26,640

Development	74,981	58,600	147,403	116,696
Exploration	37,739	8,491	63,778	18,699
Total natural gas and oil capital expenditures	132,075	80,097	278,387	164,735
Producing property dispositions [2]		(59,429)	(150)	(72,567)
Net natural gas and oil capital expenditures	$ 132,075	$ 20,668	$ 278,238	$ 92,168

(1) Leasehold and lease acquisition costs include capitalized interest and general and administrative expenses of $6.2 million and $5.7 million, respectively, for the three months ended June 30, 2005 and 2004 and $12.5 million and $11.8 million, respectively, for the six months ended June 30, 2005 and 2004.

(2) Producing property dispositions during 2004 include $13.1 million associated with the divestment of our South Louisiana operations in February 2004 and $59.4 million associated with the divestment of our Appalachian Basin properties

as part of the asset exchange transaction with KeySpan in June 2004.

Financing Activities. During the first six months of 2005, total long-term debt decreased by a net $25 million, as we used cash generated from operations to repay borrowings under our revolving bank credit facility. Subsequent to June 30, 2005, we repaid an additional $5 million under our revolving bank credit facility, reducing outstanding bank borrowings to $150 million as of August 2, 2005.

Access to Capital Markets. We have remaining capacity to offer up to $750 million of our common stock, preferred stock, depositary shares and debt securities, or a combination of any of these securities under shelf registration statements filed with the SEC in March and October 2004.

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 2005. 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 future 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.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements to enhance liquidity and capital resource positions, or for any other purpose.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Market Risk

Our major market risk exposure continues to be the prices applicable to our natural gas and oil production. Our sales price is primarily driven by the prevailing market price. Historically, prices received for our natural gas and oil production have been volatile and unpredictable.

Interest Rate Market Risk

At June 30, 2005, total debt was $330 million, of which approximately 53%, or $175 million, is fixed at an interest rate of 7%. The remaining 47% of our total debt balance at June 30, 2005, or $155 million, represents our bank debt that is tied to floating or market interest rates. Fluctuations in floating interest rates will cause our annual interest costs to fluctuate. During the first six months of 2005, the interest rate on our outstanding bank debt averaged 4.88%. If the balance of our bank debt at June 30, 2005, were to remain constant, a 10% change in market interest rates would impact our cash flow by approximately $0.2 million per quarter.

Commodity Risk

We utilize derivative commodity instruments to hedge future sales prices on a portion of our natural gas and oil production to achieve a more predictable cash flow, as well as to reduce our exposure to adverse price fluctuations of natural gas. Our derivatives are not held for trading purposes and our hedging policy prescribes that all hedge structures meet the requirements for hedging accounting under SFAS 133 and that each transaction is specifically identified as a hedge for Federal income tax purposes as defined in Section 1221(b)(2) of the Internal Revenue Code. 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, net of tax, 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 and would be included as a component of the line item natural gas and oil revenues. For us, ineffectiveness is primarily a result of changes at the end of each 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.

Changes in Fair Value of Derivative Instruments

The following table summarizes the change in the fair value of our derivative instruments for each of the six-month periods from January 1 to June 30, 2005 and 2004, and provides the fair value at the end of each period.

	Six Months Ended June 30,	
	2005	**2004**
Change in Fair Value of Derivatives Instruments:	Before Tax (in thousands)	
Fair value of contracts at January 1	$ (75,149)	$ (36,862)
Realized loss on contracts settled	38,510	24,799
(Decrease) in fair value of all open contracts	(194,921)	(94,325)
Net (decrease) during period	(156,411)	(69,526)
Fair value of contracts outstanding at June 30	$ (231,560)	$ (106,388)

Derivatives in Place as of the Date of Our Report

As of August 4, 2005, the following table summarizes, on a daily basis, our natural gas hedges in place for 2005, 2006, 2007 and 2008. For the remaining six months of 2005, we have hedged approximately 70% of our estimated production, or a total of 260,000 million British thermal units per day (MMBtu/day).

Year	Transaction Type	Daily Volume (MMBtu/day)	NYMEX Price ($/MMBtu)	Floor Price ($/MMBtu)	Ceiling Price ($/MMBtu)
2005	Swap	20,000	$ 4.75		
2005	Swap	10,000	4.77		
2005	Swap	20,000	4.78		
2005	Swap	20,000	6.15		
2005	Swap	10,000	6.30		
	Total swaps	80,000			
2005	Costless collar	100,000		$ 4.50	$ 5.50
2005	Costless collar	30,000		4.50	6.05
2005	Costless collar	10,000		4.50	6.06
2005	Costless collar	10,000		4.50	6.07
2005	Costless collar	10,000		6.50	10.15
2005	Costless collar	20,000		6.50	10.19
	Total collars	180,000			
Total daily volume 2005		260,000			

2006	Swap	20,000	$	5.87				
2006	Swap	10,000		5.94				
	Total swaps	30,000						
2006	Costless collar	10,000			$	5.50	$	7.20
2006	Costless collar	10,000				5.50		7.25
2006	Costless collar	40,000				5.50		7.26
2006	Costless collar	20,000				5.75		7.20
2006	Costless collar	30,000				5.80		7.00
2006	Costless collar	50,000				5.82		7.00
2006	Costless collar	30,000				6.00		7.00
2006	Costless collar	20,000				6.00		7.02
2006	Costless collar	10,000				6.00		7.05
	Total collars	220,000						
Total daily volume 2006		250,000						

Year	Transaction Type	Daily Volume (MMBtu/day)	NYMEX Price ($/MMBtu)	Floor Price ($/MMBtu)	Ceiling Price ($/MMBtu)
2007	Costless collar	20,000		$ 5.00	$ 6.50
2007	Costless collar	10,000		5.00	6.79
Total daily volume 2007		30,000			
2008	Costless collar	20,000		$ 5.00	$ 5.72
Total daily volume 2008		20,000			

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

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we conducted an evaluation of our disclosure controls and procedures, as this term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act). Based on this evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures were effective as of the end of the period covered by this Quarterly Report.

Changes in Internal Control Over Financial Reporting

No change in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) occurred during the three months ended June 30, 2005, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Part II. Other Information

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

On April 26, 2005, we held our annual meeting of stockholders. Information regarding our meeting is included under Item 4 of our Quarterly Report on Form 10-Q for the quarter ended March 31, 2005.

Item 5. Other Information

Item 6. Exhibits

EXHIBITS	DESCRIPTION

4.1	Amendment No. 1 to Registration Statement on Form 8-A (File No. 001-11899) filed with the Securities and Exchange Commission on May 26, 2005, and incorporated by reference herein.
4.2	Amendment No. 2 to Registration Statement on Form 8-A (File No. 001-11899) filed with the Securities and Exchange Commission on May 26, 2005, and incorporated by reference herein.
12.1[1]	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, Chief Financial Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

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EXHIBITS	DESCRIPTION
32.1[1]	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2[1]	Certification of John H. Karnes, Chief Financial Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

[1] Filed herewith.

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SIGNATURES

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

	THE HOUSTON EXPLORATION COMPANY	
	By:	/s/ William G. Hargett
Date: August 2, 2005		William G. Hargett Chairman, President and Chief Executive Officer
	By:	/s/ John H. Karnes
Date: August 2, 2005		John H. Karnes Senior Vice President and Chief Financial Officer
	By:	/s/ James F. Westmoreland
Date: August 2, 2005		James F. Westmoreland Vice President and Chief Accounting Officer

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EXHIBITS	DESCRIPTION
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