HOUSTON EXPLORATION CO
Form 10-Q
August 08, 2006

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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, 2006

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 a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

As of August 7, 2006, 27,994,964 shares of Common Stock, par value $0.01 per share, were outstanding.

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Forward-Looking Statements

Certain statements in this Quarterly Report on Form 10-Q (Quarterly Report) and the documents we have incorporated by reference into this Quarterly Report, other than purely historical information, including estimates, projections, statements relating to our business plans, strategies, objectives and expected operating results, and the assumptions upon which those statements are based, are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, 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 forward-looking statements generally may be identified by the words believe, project, expect, anticipate, estimate, intend, str plan, target, pursue, may, will, would, will continue, will likely result, and similar expressions. Forwar statements are based on current expectations and assumptions that are subject to numerous risks and uncertainties which may cause actual results to differ materially from the forward-looking statements. A detailed discussion of these and other risks and uncertainties that could cause actual results and events to differ materially from such forward-looking statements is included in Item 1A. Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2005, as amended, our Quarterly Report on Form 10-Q for the three months ended March 31, 2006 and this Quarterly Report, as well as Risk Factors set forth from time to time in our filings with the Securities and Exchange Commission (SEC). We undertake no obligation to update or revise publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

Available Information

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are available free of charge on our Web site at http://www.houstonexploration.com as soon as reasonably practicable after we electronically file such material with, or otherwise furnish it to, the SEC.

Information contained on or connected to our Web site is not incorporated by reference into this Quarterly Report and should not be considered part of this report or any other filing that we make with the SEC.

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 our subsidiaries, THEC, LLC and THEC, LP, on a consolidated basis. Also, unless the context requires otherwise, we are reporting historical results as of June 30, 2006 and December 31, 2005, and for the three-month and six-month periods ended June 30, 2006 and 2005.

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, 2005, as amended. 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, 2006	December 31, 2005
Assets:		
Cash and cash equivalents	$ 3,488	$ 7,979
Accounts receivable	83,390	146,020
Inventories	4,215	2,726
Deferred tax asset	67,439	145,922
Prepayments and other	15,549	19,709
Total current assets	174,081	322,356
Natural gas and oil properties, full cost method		
Unevaluated properties	39,381	107,146
Properties subject to amortization	3,129,560	3,556,755
Other property and equipment	13,880	12,971
	3,182,821	3,676,872
Less: Accumulated depreciation, depletion and amortization	1,799,997	1,658,532
	1,382,824	2,018,340
Designated cash	323,675	
Other non-current assets	16,730	20,928
Total non-current assets	340,405	20,928
Total Assets	$ 1,897,310	$ 2,361,624
Liabilities:		
Accounts payable and accrued expenses	$ 185,743	$ 177,159
Derivative financial instruments	44,165	352,457
Asset retirement obligation		7,265
Total current liabilities	229,908	536,881
Long-term debt and notes	275,000	597,000
Derivative financial instruments	36,928	65,201
Deferred income taxes	410,511	341,302
Asset retirement obligation	36,868	112,406

Other non-current liabilities	10,648	15,696
Total Liabilities	999,863	1,668,486
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, $0.01 par value, 100,000,000 shares authorized and 27,942,610 and 28,980,128 shares issued and outstanding at June 30, 2006 and December 31, 2005, respectively	279	289
Additional paid-in capital	245,100	297,218
Retained earnings	716,510	663,367
Accumulated other comprehensive (loss)	(64,442)	(267,736)
Total Stockholders Equity	897,447	693,138
Total Liabilities and Stockholders Equity	$ 1,897,310	$ 2,361,624

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,	
	2006	**2005**	**2006**	**2005**
Revenues:				
Natural gas and oil revenues	$ 143,813	$ 175,524	$ 320,832	$ 341,014
Other	2,101	293	2,686	523
Total revenues	145,914	175,817	323,518	341,537
Operating expenses:				
Lease operating	18,032	19,124	39,844	34,492
Severance tax	4,830	4,530	10,989	7,464
Transportation expense	2,859	2,993	5,630	5,759
Asset retirement accretion expense	1,069	1,326	2,396	2,651
Depreciation, depletion and amortization	57,858	71,944	141,619	142,547
General and administrative, net of amounts capitalized	8,705	6,200	17,311	17,323
Total operating expenses	93,353	106,117	217,789	210,236
Income from operations	52,561	69,700	105,729	131,301
Other (income) expense	(791)	(1,067)	(2,198)	387
Interest expense, net of amounts capitalized	6,451	3,196	15,172	6,630
Income before income taxes	46,901	67,571	92,755	124,284
Provision for taxes	23,530	23,741	39,612	47,016
Net income	$ 23,371	$ 43,830	$ 53,143	$ 77,268
Earnings per share:				
Net income per share basic	$ 0.82	$ 1.53	$ 1.85	$ 2.70
Net income per share diluted	$ 0.81	$ 1.51	$ 1.84	$ 2.67
Weighted average shares outstanding basic	28,625	28,679	28,770	28,589
Weighted average shares outstanding diluted	28,678	28,973	28,824	28,920

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, 2006	2005
Operating Activities:		
Net income	$ 53,143	$ 77,268
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	141,619	142,547
Deferred income tax expense	36,293	30,988
Asset retirement accretion expense	2,396	2,651
Stock compensation expense	4,872	2,022
Tax benefit from non-qualified stock options		1,881
Unrealized (gain) loss on derivative instruments	(21,871)	1,424
Debt extinguishment	572	
Changes in operating assets and liabilities:		
Accounts receivable	62,630	1,063
Inventories	(1,489)	(663)
Prepayments and other	4,160	6,397
Other non-current assets	3,825	1,411
Accounts payable and accrued expenses	(27,795)	(11,160)
Other non-current liabilities	(5,048)	1,363
Net cash provided by operating activities	253,307	257,192
Investing Activities:		
Investment in property and equipment	(278,572)	(254,836)
Designated cash	(323,675)	
Dispositions and other	723,648	165
Net cash provided by (used in) investing activities	121,401	(254,671)
Financing Activities:		
Proceeds from long-term borrowings	340,000	207,000
Repayments of long-term borrowings	(662,000)	(232,000)
Proceeds from issuance of common stock from exercise of stock options	4,426	8,596
Repurchase of common stock	(61,638)	
Debt issue costs	(199)	
Tax benefit from non-qualified stock options	212	
Net cash used in financing activities	(379,199)	(16,404)
Decrease in cash and cash equivalents	(4,491)	(13,883)
Cash and cash equivalents, beginning of period	7,979	18,577
Cash and cash equivalents, end of period	$ 3,488	$ 4,694

Supplemental Information:		
Non-cash transactions:		
Investments in property and equipment accrued, not paid	$ (36,379)	$ (24,046)
Cash paid during period for:		
Interest	$ 16,470	$ 10,494
Federal and state income taxes		10,860

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. We were founded in December 1985 as a Delaware corporation and wholly-owned subsidiary of our then parent company, KeySpan Corporation. We completed our initial public offering in September 1996. Through three separate transactions, the last of which occurred in November 2004, KeySpan completely divested of its ownership in the common stock of our company. At June 30, 2006, we had operations in four producing regions within the United States: South Texas; the Arkoma Basin of Arkansas and Oklahoma; East Texas; and the Uinta and DJ Basins in the Rocky Mountains.

In November 2005, we announced a strategic plan to restructure the company by pursuing the sale of our Gulf of Mexico assets, shifting our operating focus primarily onshore and repurchasing up to $200 million of our outstanding common stock. On March 31, 2006, we completed the sale of the Texas portion of our Gulf of Mexico assets and on June 1, 2006, we completed the sale of substantially all of our Louisiana Gulf of Mexico assets (see Note 6 Acquisitions and Dispositions*)*. The sale of these assets had a significant impact on our operating results for both the three- and six-month periods ended June 30, 2006 and on the comparability of those results both quarter-over-quarter and period-over-period. We received $721.6 million in net cash proceeds from the sale of substantially all of our Gulf of Mexico assets, of which we used $374.0 million to repay and reduce borrowings under our revolving credit facility; deposited $323.7 million with qualified intermediaries for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code; and used the balance of $23.9 million for working capital purposes.

On June 12, 2006, we received an unsolicited proposal from JANA Partners LLC, a hedge fund, to acquire our company for $62 per share. According to its public filings, JANA Partners beneficially owned approximately 12.3% of our outstanding common stock as of the date of the proposal. On June 26, 2006, we announced our Board of Directors determination that the unsolicited proposal made by JANA Partners was not in the best interest of our shareholders and that Lehman Brothers Inc. had been engaged to assist us in exploring a broad range of strategic alternatives to further enhance shareholder value. These alternatives may complement or replace the continued execution of our previously announced business plan and include, but are not limited to, a recapitalization of our company either through additional share repurchases or a special dividend; operating partnerships and / or strategic alliances; and the sale or merger of the company. As of the date of this Quarterly Report, this strategic review is ongoing.

Principles of Consolidation

Our consolidated financial statements include our accounts and the accounts of our wholly-owned subsidiaries. All significant inter-company balances and transactions have been eliminated.

Interim Financial Statements

Our balance sheet at June 30, 2006, 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 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, 2005 is derived from our December 31, 2005 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, 2005, as amended.

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

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

at the dates of the financial statements, as well as the reported amounts of revenues and expenses during the reporting periods. Our most significant 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.

Reclassifications

Certain reclassifications have been made to prior year amounts to conform to the current year presentation.

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 engage in activities from which they may earn revenues and incur expenses, and for which separate financial information is available and 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 applicable.

At June 30, 2006, we had production imbalances representing assets of $1.5 million and liabilities of $1.9 million. At December 31, 2005, we had production imbalances representing assets of $4.9 million and liabilities of $7.2 million, which included imbalances related to our offshore properties that were sold during the first six months of 2006. The primary source of our production imbalances at June 30, 2006 relate to various Arkoma wells. A significant portion of these imbalances was assumed in connection with our initial acquisition of the properties, and due to the inherent long life and comparatively low production rate of the wells, the imbalances will likely require a long period of time to resolve. Production imbalances are included in the line items other non-current assets and other non-current liabilities on our balance sheet.

Cash and Cash Equivalents

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

Designated Cash

In connection with the sale of our Gulf of Mexico assets (see Note 6 Acquisitions and Dispositions), we deposited $323.7 million of cash proceeds received from the sale of these assets with qualified intermediaries for potential reinvestment in

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

like-kind exchange transactions under Section 1031 of the Internal Revenue Code. This cash has been designated for the potential future acquisition of natural gas and oil assets and has been invested in interest-bearing accounts with creditworthy financial institutions. The designated cash is classified on our balance sheet as a non-current asset. Interest earned on the designated funds was approximately $1.6 million during the three-month and six-month periods ended June 30, 2006. Interest income earned is not designated for potential reinvestment in replacement properties and is included in the line item other revenue on our statement of operations.

Net Income Per Share

Basic net income per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding during the period. Diluted net income 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. For us, potentially dilutive common shares consist primarily of employee stock options and restricted common stock and units.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(in thousands, except per share data)			
Numerator:				
Net income	$ 23,371	$ 43,830	$ 53,143	$ 77,268
Denominator:				
Weighted average shares outstanding	28,625	28,679	28,770	28,589
Add dilutive securities: options and restricted stock/units	53	294	54	331
Total weighted average shares outstanding and dilutive securities	28,678	28,973	28,824	28,920
Net Income per share basic:	$ 0.82	$ 1.53	$ 1.85	$ 2.70
Net Income per share diluted:	$ 0.81	$ 1.51	$ 1.84	$ 2.67

For the three months ended June 30, 2006 and 2005, the calculation of shares outstanding for net income per share on a diluted basis does not include the effect of outstanding stock options to purchase 591,563 and 393,370 shares, respectively, because the exercise price for these shares was greater than the average market price for the respective periods, which would have an antidilutive effect on net income per share. For the six months ended June 30, 2006 and 2005, the calculation of shares outstanding for net income per share on a diluted basis does not include the effect of outstanding stock options to purchase 628,347 and 387,678 shares, respectively, because the exercise price for these shares was greater than the average market price for the respective periods, which would have an antidilutive effect on net income per share.

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income and certain items recorded directly to stockholders equity and classified as other comprehensive income (loss). The table below summarizes comprehensive income (loss) and provides the components of the change in accumulated other comprehensive income (loss) for the three-month and six-month periods ended June 30, 2006 and 2005.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(in thousands)			
Net income	$ 23,371	$ 43,830	$ 53,143	$ 77,268
Other comprehensive income (loss)				
Derivative contracts settled and reclassified, net of tax	11,903	15,720	41,958	24,877
Change in fair value of open derivative contracts, net of tax	21,103	11,860	161,336	(124,999)
Change in accumulated other comprehensive income (loss)	33,006	27,580	203,294	(100,122)
Comprehensive income (loss)	$ 56,377	$ 71,410	$ 256,437	$ (22,854)

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

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 from proved reserves, 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 as adjusted for basis or location differentials, held constant over the life of the reserves. Historically, we have used derivative financial instruments to hedge against the volatility of natural gas prices. If our derivative contracts qualify and if they are designated as cash flow hedges under SFAS 133, Accounting for Derivative Instruments and Hedging Activities, then in accordance with SEC guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation. Since our derivative contracts ceased to qualify as cash flow hedges during the first quarter of 2006, our ceiling test calculation at June 30, 2006 did not include the future cash flows from our hedging program. In addition, subsequent to the adoption of SFAS 143, Accounting for Asset Retirement Obligations, the future cash outflows associated with settling asset retirement obligations (ARO) 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, 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 classified as unevaluated property are assessed on a quarterly basis for possible impairment or reduction in value. We estimate that substantially all of these costs will be evaluated within a four-year period. In connection with the completion of the sale of substantially all of our Gulf of Mexico assets during the first six months of 2006, unevaluated properties were reduced by approximately $75.8 million.

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

Asset Retirement Obligations

The following table describes changes in our ARO liability during each of the six-month periods ended June 30, 2006 and 2005. The ARO liability in the table below includes amounts classified as both current and long-term at the end of the respective periods.

	Six Months Ended June 30, 2006	2005
	(in thousands)	
ARO liability at January 1,	$ 119,671	$ 91,746
Accretion expense	2,396	2,651
Liabilities incurred drilling	3,252	2,530
Liabilities incurred assets acquired		169
Liabilities settled assets abandoned		(870)
Liabilities settled assets sold	(88,375)	(32)
Changes in estimates	(76)	798
ARO liability at June 30,	$ 36,868	$ 96,992

Derivative Instruments and Hedging Activities

To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we have historically utilized derivative instruments to hedge future sales prices on a significant portion of our natural gas production. Our derivative instruments are not held for trading purposes and our hedging policy prescribes that at the time we enter into any derivative contract, the contract must meet the requirements for hedge accounting under SFAS 133 and must be specifically identified as a hedge for federal income tax purposes. Our hedging policy allows us to implement a wide variety of hedging strategies, including swaps, collars and options. We generally execute derivative contracts with significant, creditworthy financial institutions. Although our hedging program is intended to protect a portion of our cash flows from downward price movements, certain hedging strategies, specifically the use of swaps and collars, may also limit our ability to realize the full benefit of future price increases, as in recent years. In addition, because our derivative instruments are typically indexed to the New York Mercantile Exchange (NYMEX) price, as opposed to the index price where the gas is actually sold, our hedging strategy may not fully protect our cash flows when there are significant price differentials between the NYMEX price and index price at the point of sale, as was the case during the second half of 2005 and the first quarter of 2006 due to the continuing impact of Hurricanes Katrina and Rita.

At inception, all of our existing derivative contracts qualified for hedge accounting and were designated as cash flow hedges. Under hedge accounting, derivative contracts designated as cash flow hedges are recorded on the balance sheet as either an asset or liability at fair market value and changes in fair market value (representing unrealized gains or losses) are deferred 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 when sale of the related production occurs. The portion of the derivative instrument that is ineffective as a hedge, if any, is recorded directly to the income statement and is included as a component of natural gas and oil revenues. For us, ineffectiveness typically results from changes at the end of the current period in the price differentials between the index price of the derivative contract, which typically is a NYMEX price, and the index price for the point of sale for the cash flow that is being hedged.

Under SFAS 133, we are required to assess the effectiveness of all our derivative contracts at inception and at least every three months. If our derivative contracts cease to be effective as cash flow hedges, they no longer qualify for hedge accounting. Mark-to-market accounting is then utilized. Amounts deferred in accumulated other comprehensive income are fixed at the time they cease to qualify for hedge accounting and remain deferred in accumulated other comprehensive income until the related production occurs, at which time they are reclassified to income. Subsequent changes in the fair market value of the derivative contracts (representing unrealized gains or losses) are recognized in income as a component of natural gas and oil revenues.

During the fourth quarter of 2005, the portion of our hedged production allocated to the Houston Ship Channel index failed to qualify for hedge accounting due to a loss of correlation with the NYMEX price caused primarily by the impact of Hurricanes Katrina and Rita. During the first quarter of 2006, the portion of our hedged production allocated to the Arkoma index failed to qualify for hedge accounting due to a loss of correlation with the NYMEX price caused in part by

THE HOUSTON EXPLORATION COMPANY
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the residual effects of the hurricanes, as well as an increase in the natural gas supply in the mid-continent region due in part to a mild winter and pipeline expansions in the region. Finally, in February 2006 in connection with our entry into a definitive purchase and sale agreement to sell the Texas portion of our Gulf of Mexico assets (see Note 6 Acquisitions and Dispositions *Sale of Texas Gulf of Mexico Assets*), the remaining portion of our open derivative contracts that previously qualified for hedge accounting ceased to qualify. As a result, subsequent to February 2006, mark-to-market accounting applies to all of our open derivative contracts, and changes in the fair market value of these open contracts are recognized in income as either a gain or loss and included as a component of natural gas and oil revenues.

In connection with the completion of the divestiture of our Gulf of Mexico assets on June 1, 2006, we were required under our revolving credit facility to liquidate a portion of our 2006 hedge position. In order to comply with this requirement, in June 2006, we liquidated and settled open contracts covering 60,000 MMBtu per day of hedged production for each of the months July through December 2006. The cost to unwind and settle these contracts was approximately $14.3 million. After unwinding these contracts, our weighted average open derivative position for the remaining months of 2006 (July through December) decreased from 250,000 MMBtu per day to 190,000 MMBtu per day. In addition, on August 4, 2006, we liquidated and settled open derivative contracts representing 20,000 MMBtu per day of hedged production for each of the months September and October 2006. The cost to unwind and settle these contracts was approximately $0.9 million (see Note 7 Subsequent Events *Liquidation of Derivative Contracts*). After unwinding these contracts, our weighted average open derivative position for the remaining months of 2006 (July through December) decreased from 190,000 MMBtu per day to 183,333 MMBtu per day, which is approximately 83% of forecasted equivalent natural gas and oil production for the six-month period ending December 31, 2006.

At June 30, 2006, an unrealized loss of $64.4 million, net of tax, remains deferred in accumulated other comprehensive income. This loss represents the fixed value of our remaining open derivative contracts deferred in accumulated other comprehensive income at the time they ceased to qualify for hedge accounting. All of these deferred losses will be reclassified and recognized in future earnings at the time when sale of the related natural gas production occurs. Over the next 12-month period, we expect to reclassify from accumulated other comprehensive income to earnings a loss of $52.1 million, net of tax, leaving $12.3 million to be recognized thereafter.

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 SFAS 148. Accordingly, we recognized compensation expense for all stock options granted subsequent to January 1, 2003. On January 1, 2006, we adopted SFAS 123(R), Share-Based Payment. Accordingly, we now recognize compensation expense for all stock options, including the unvested portion of all grants made prior to our initial adoption of SFAS 123 on January 1, 2003. Prior period amounts have not been restated. Prior to adopting SFAS 123 in January 2003 and SFAS 123(R) in January 2006, 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.

If we had accounted for all stock options using the fair value method as recommended in SFAS 123 and 123(R), compensation expense would have had the following pro forma effect on our net income and earnings per share for the three-month and six-month periods ended June 30, 2005 (all amounts in thousands, except per share amounts):

	Three Months Ended June 30, 2005	Six Months Ended June 30, 2005
Net income as reported	$ 43,830	$ 77,268

Add: Stock-based compensation expense included in net income, net of tax.		428		874
Less: Stock-based compensation expense determined using fair value method, net of tax		(785)		(1,586)
Net income pro forma	$	43,473	$	76,556
Net income per share basic as reported	$	1.53	$	2.70
Net income per share diluted as reported		1.51		2.67
Net income per share basic pro forma	$	1.52	$	2.68
Net income per share diluted pro forma		1.50		2.65

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The weighted average fair value of options granted and valuation assumptions used in the Black-Scholes option-pricing model during the six-month periods ended June 30, 2006 and 2005 are as follows:

	Six Months Ended June 30,	
	2006	**2005**
Weighted average fair value of options granted	$12.37	$20.89
Assumptions:		
Risk-free interest rate	4.76%	3.97%
Expected years until exercise	3	5
Expected stock volatility	25.3%	34.7%
Expected dividends		

The Black-Scholes option pricing model requires the input of certain subjective assumptions, including the expected stock price volatility and expected life of the option. For the risk-free interest rate, we utilize daily rates for either five-year or three-year United States treasury bills with constant maturity that correspond to the option s vesting period. The expected life is based on historical exercise activity over the previous ten-year period. The expected volatility is based on historical volatility and measured using the average closing price of our stock over a 36-month period. We believe historical volatility is the most accurate measure of future volatility of our common stock. Our expected rate of forfeitures is estimated at 5% and is based on historical forfeiture rates over the previous ten-year period.

The following table provides the detail of stock compensation expense incurred during each of the three-month and six-month periods ended June 30, 2006 and 2005:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	**2005**	**2006**	**2005**
	(in thousands)			
Options	$ 1,562	$ 766	$ 3,249	$ 1,583
Restricted stock/units	793	244	1,623	439
Stock compensation expense, gross	2,355	1,010	4,872	2,022
Amounts capitalized	(713)	(347)	(1,748)	(669)
Stock compensation expense, net of amounts capitalized	$ 1,642	$ 663	$ 3,124	$ 1,353

Amounts capitalized are categorized as leasehold costs and included as a component of our natural gas and oil property balance or full cost pool. Amounts expensed are included as a component of general and administrative expense. At June 30, 2006, our unrecognized stock compensation expense related to unvested stock options to be recognized over a weighted average four-year period and included as a component of Additional Paid-in Capital was approximately $8.6 million. At June 30, 2006, unearned compensation expense related to restricted stock and units and expected to be recognized over a weighed average four-year period totaled $7.5 million and is included as a component of additional paid-in capital.

Stock Plans. We have four stock option plans (together, our Stock Plans): (i) the 1996 Stock Option Plan, which was adopted at the completion of our initial public offering in September 1996, and amended and approved by our stockholders in 1997; (ii) the 1999 Non-Qualified Stock Option Plan adopted by our Board of Directors in October 1999; (iii) the 2002 Long-Term Incentive Plan adopted in January 2002, approved by our stockholders in

May 2002 and amended by our Board in October 2003; and (iv) the 2004 Long-Term Incentive Plan, approved by our stockholders in June 2004 and amended and restated by our Board in January 2006. All our employees, directors, consultants and advisors are eligible to participate in our Stock Plans, with the exception of executive officers who are not eligible to participate in the 1999 plan. The 1996, 2002 and 2004 plans allow for the granting of both incentive stock options and non-qualified stock options, and the 2002 and 2004 plans allow for the granting of restricted stock. Upon shareholder approval of the 2004 plan, all remaining options available for grant under the 2002, 1999 and 1996 plans were cancelled, and 1,500,000 shares were authorized for awards under the 2004 plan, with a limit of 300,000 shares for restricted stock grants. At June 30, 2006, we had 654,085 shares authorized and available for award under the 2004 plan.

Stock Options. Options granted under our Stock Plans expire 10 years from the grant date and vest in equal annual increments over either a five-year or three-year vesting period, with the exception of options granted to directors whose options vest immediately upon grant. In general, stock options become fully vested upon the occurrence of a change of control, unless an award agreement provides otherwise. All stock options have an exercise price equal to the closing price of our common stock as reported on the NYSE on the date of grant. After the amendment and restatement of the 2004 plan

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in January 2006, non-employee directors are no longer eligible to receive stock options and instead will receive an annual grant of restricted stock, the number of shares of which is determined by dividing $100,000 by the closing price of our common stock on the date of our Annual Meeting of Stockholders.

Common stock issued through the exercise of non-qualified stock options will result in a tax deduction for us which is equal to the taxable gain recognized by the optionee. Generally, we will not receive an income tax deduction for incentive stock options. For financial reporting purposes, the tax effect of this deduction is accounted for as a credit to additional paid-in-capital rather than as a reduction of income tax expense. Prior to the adoption of SFAS 123(R) on January 1, 2006, we presented tax benefits resulting from stock-based compensation as a cash flow from operating activities within our consolidated statements of cash flows. SFAS 123(R) requires excess tax benefits to be presented as a cash flow from financing activities. For the three-month and six-month periods ended June 30, 2006, we recognized excess tax expense of $0.2 million and excess tax benefit of $0.2 million, respectively. For the corresponding three-month and six-month periods ended June 30, 2005, we recognized excess tax benefits of $0.2 million and $1.9 million, respectively.

The following table below summarizes the activity with respect to stock options for the six months ended June 30, 2006:

	Shares Underlying Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value[(1)]
	(shares)	($/share)	(Years)	($ in thousands)
Options outstanding January 1, 2006	1,696,610	$ 39.85	7.8	$ 21,971
Granted	40,775	52.85		2,155
Exercised	(113,375)	39.03		2,346
Forfeited	(40,800)	42.94		
Options outstanding June 30, 2006	1,583,210	$ 40.17	5.9	$ 33,279
Options exercisable June 30, 2006	626,563	$ 31.80	2.6	$ 18,412

(1) The intrinsic value of an option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option, or the market price at the end of the

period less the exercise price. At June 30, 2006 and December 31, 2005, the closing price per share of our common stock on the NYSE was $61.19 and $52.80, respectively.

The total intrinsic value of options exercised during the three-month and six-month periods ended June 30, 2006 was $0.5 million and $2.3 million, respectively. For the corresponding three-month and six-month periods ended June 30, 2005, the total intrinsic value of options exercised during these periods was $0.5 million and $7.5 million, respectively.

Restricted Stock. Restricted stock may be granted and issued to executive officers, employees, non-employee directors and affiliated directors as a component of each recipient s annual compensation, and vesting is generally dependent upon continued service to our company. Restricted stock carries voting and dividend rights; however, the sale or transfer of the shares is restricted. Generally, restricted shares vest and become freely transferable at the end of the vesting period, which is either five years or three years from the date of grant. In general, accelerated vesting will occur upon the occurrence of certain events, including a change of control (as defined by the plan), unless an award agreement provides otherwise, and in the case of non-employee directors, termination as a director by reason of death, disability or retirement. Restricted stock awards are valued at the closing price of our common stock on the date of grant.

The following table below summarizes the activity with respect to restricted stock and units for the six months ended June 30, 2006:

	Restricted Stock and Units[(1)] (shares)	**Weighted Average Grant Date Fair Value** ($/share)	**Aggregate** Intrinsic Value[(2)] ($ in thousands)
Unvested restricted stock January 1, 2006	171,214	$ 56.23	$ 9,040
Granted	25,016	54.16	1,531
Vested	(803)	58.88	49
Forfeited	(5,798)	58.88	
Unvested restricted stock June 30, 2006	189,629	$ 55.87	$ 11,603

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(1) Includes 52,501 units granted in July 2005 pursuant to a retention bonus plan for certain employees at an average price of $58.76 per unit, of which 50% vest 18 months following the grant date with the remaining 50% to vest 36 months following the grant date. Restricted units will convert to shares of restricted stock at the end of the vesting period. At June 30, 2006, 46,703 units under the retention bonus plan were unvested and outstanding.

(2) For unvested shares of restricted stock, the intrinsic value is calculated using the closing price of our common stock at the end of the period. For restricted shares that vested during

the period, the intrinsic value is calculated using the closing price of our common stock on the vesting date. At June 30, 2006 and December 31, 2005, the closing price per share of our common stock on the NYSE was $61.19 and $52.80, respectively.

Recent Accounting Pronouncements

In July 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement 109 (FIN 48) , which clarifies the accounting for uncertainty in tax positions taken or expected to be taken in a tax return, including issues relating to financial statement recognition and measurement. FIN 48 provides that the tax effects from an uncertain tax position can be recognized in the financial statements only if the position is more-likely-than-not to be sustained if the position were to be challenged by a taxing authority. The assessment of the tax position is based solely on the technical merits of the position, without regard to the likelihood that the tax position may be challenged. If an uncertain tax position meets the more-likely-than-not threshold, the largest amount of tax benefit that is more than 50 percent likely to be recognized upon ultimate settlement with the taxing authority, is recorded. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. We are currently evaluating the impact of adopting FIN 48 on our financial statements.

NOTE 2 Long-Term Debt and Notes

	June 30, 2006	December 31, 2005
	(in thousands)	
Senior Debt:		
Revolving credit facility, due November 30, 2010	$ 100,000	$ 422,000
Subordinated Debt:		
7% senior subordinated notes, due June 15, 2013	175,000	175,000
Total long-term debt and notes	$ 275,000	$ 597,000

The carrying amount of borrowings outstanding under our revolving credit facility approximates fair value as the interest rates are tied to current market rates. At June 30, 2006, the quoted market value of our $175 million of 7% senior subordinated notes was 95.0% of the $175 million carrying value, or $166 million. At December 31, 2005, the quoted market value of our $175 million of 7% senior subordinated notes was 95.4% of the $175 million carrying value, or $167 million.

Revolving Credit Facility

We maintain a revolving 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 Bank of America as co-syndication agents and BNP Paribas and Comerica Bank as co-documentation agents. The facility provides us with a commitment of

$750 million, which may be increased at our request and with prior approval from the required lenders to a maximum of $850 million. Amounts available for borrowing under the credit facility are limited to a borrowing base that is redetermined semi-annually on April 1st and October 1st. Effective June 1, 2006, in connection with the completion of the sale of the Louisiana portion of our Gulf of Mexico assets, our borrowing base of $550 million was reduced to $500 million. Up to $60 million of our borrowing base is available for the issuance of letters of credit. In connection with the decrease in the borrowing base, we incurred debt extinguishment expense of $0.6 million during the second quarter of 2006 relating to the write-off of a portion of our debt issue costs. We expect our current borrowing base of $500 million to remain in effect until the next scheduled semi-annual redetermination on October 1, 2006. Outstanding borrowings under the revolving credit facility are secured by our onshore natural gas and oil assets as well as certain other assets and rank senior in right of payment to our $175 million, 7% senior subordinated notes. The facility matures on November 30, 2010. At June 30, 2006, we had $100 million in outstanding borrowings under the credit facility and $0.3 million in outstanding letter of credit obligations.

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Interest is payable on borrowings under our revolving 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 1.00% and 1.75%, 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 credit facility contains customary financial and other covenants that place restrictions and limits on, among other things, the incurrence of debt, guarantees, liens, leases and certain investments. The credit facility also restricts and limits our ability to pay cash dividends, purchase or redeem our stock, and 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

§ hedge no more than 85% of our production during any calendar year.

At June 30, 2006 and December 31, 2005, we were in compliance with all covenants under our revolving credit facility.

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. 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, prior to June 15, 2006, we had the right to 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 of our existing and future senior debt, including the revolving 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 proceeds of assets sales;

§ transactions with affiliates;

§ creation, incurrence or assumption of liens;

§ merger or consolidation and sales or other dispositions of all or substantially all of our assets;

§ entering into agreements that restrict the ability of our subsidiaries to make certain distributions or payments; and

§ guarantees by our subsidiaries of certain indebtedness.

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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.

At June 30, 2006 and December 31, 2005, we were in compliance with all covenants under the indenture governing the notes.

NOTE 3 Stockholders Equity

Stock Repurchase Authorization

On November 4, 2005, and in conjunction with the then planned divestiture of all of our Gulf of Mexico assets, our Board of Directors approved discretionary repurchases from time to time over twelve months ending November 4, 2006 of up to $200 million in company stock. These purchases may occur in the open market or in privately negotiated transactions, and will be subject to a number of considerations, including market conditions for our shares, applicable legal requirements, contractual limitations, available cash, competing reinvestment opportunities in the acquisition market for oil and gas assets and other factors. In May 2006, we initiated our share repurchases, and during May and June 2006, we repurchased a total of 1,176,500 shares, or approximately 4% of our outstanding common stock, in the open market at a weighted average price of $52.39 per share for a total cost of approximately $61.6 million. All repurchases were paid for in cash and funded with cash on hand or borrowings under our revolving credit facility. All repurchased shares were retired, and we expect that any stock to be repurchased in the future under this authorization will also be retired. At June 30, 2006, approximately $138.4 million was remaining under our current share repurchase authorization.

NOTE 4 Commitments and Contingencies

Taxable Gain on Sale of Gulf of Mexico Assets

We have established a structure permitting reinvestment of $323.7 million of the cash proceeds from the sale of our Gulf of Mexico assets in a manner that qualifies as a like-kind exchange under Section 1031 of the Internal Revenue Code (see Note 6 Acquisitions and Dispositions). If qualified reinvestments in natural gas and oil properties are not completed by November 27, 2006 (180 days after the closing of the sale of our Louisiana Gulf of Mexico assets), we estimate that the potential income tax liability associated with a gain on the sale of these assets that would be recognized and payable during the fourth quarter of 2006 is approximately $87 million. If any cash payment for estimated income tax is required during the fourth quarter of 2006, the payment will be based on our net taxable income, for which any gain from the sale of the Gulf of Mexico assets will be a component. At June 30, 2006, this estimated tax liability of approximately $87 million is included as a component of our deferred tax liability.

Legal Proceedings

On June 22, 2006, the City of Monroe Employees Retirement System filed a purported class action lawsuit in the District Court of Harris County, Texas, on behalf of itself and all of the company s other public shareholders, against the company and its directors. The plaintiff alleges that the defendants breached their fiduciary duties of loyalty and due care to the class because the plaintiff alleges that we failed to negotiate in good faith in response to an unsolicited proposal by JANA Partners LLC to purchase the company, and that such failure inhibits the maximization of shareholder value. In its complaint, the plaintiff requested that the court certify the plaintiff and the other public shareholders of the company as a class. In addition, the plaintiff asked the court to declare that the defendants alleged failure to negotiate in good faith was a breach of fiduciary duty; to enjoin the defendants from not negotiating in good faith with JANA Partners; to direct the individual defendants to obtain a transaction which is in the best interests of shareholders until the process for the sale or auction of the company is complete; and to award the plaintiff costs and disbursements of the action including reasonable attorneys and experts fees. On July 17, 2006, the defendants filed an Original Answer and a Motion To Abate or Special Exceptions. We believe this lawsuit is without merit and we intend to vigorously defend against it. Although it is too soon to predict the outcome of this lawsuit or the time to resolution, we do not believe that it will have a material adverse effect on our financial position, results of operations or cash flows.

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In addition to the foregoing, we are involved from time to time in various other claims and lawsuits incidental to our business. In the opinion of management, the ultimate liability, if any, associated with these matters is not expected to have a material adverse effect on our financial position, results of operations or cash flows.

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 (copiers and fax machines). The terms of these agreements have various expiration dates from 2006 through 2009. Future minimum lease payments for the remainder of 2006 and each of the subsequent four years from 2007 through 2010 are $1.0 million, $1.9 million, $1.9 million, $1.1 million and $0.6 million, respectively.

Letters of Credit

We had $0.3 million in letters of credit outstanding at each of June 30, 2006 and at December 31, 2005.

Drilling Contracts

During the first six months of 2006, we entered into two long-term contracts for the exclusive use of drilling rigs for periods of greater than or equal to 12 months. These include a one-year contract for a drilling rig in East Texas and a two-year contract for a rig in the Uinta Basin. Under the terms of these contracts, we are obligated for up to an estimated $17.6 million in fees for use of the rigs during the remaining terms of the contracts.

Supplemental Executive Retirement Plan

Effective January 1, 2006, we adopted a Supplemental Executive Retirement Plan, which was amended and restated as of July 25, 2006 (SERP), to provide retirement benefits to certain management level or other highly compensated employees. The SERP is an unfunded, non-tax qualified defined benefit pension plan. Initial participation in the SERP is currently limited to our executive officers. Participants in the SERP will be entitled to a monthly retirement benefit payable for life. The amount of this monthly retirement benefit is equal to 2.5% times final average compensation times years of service with the company (not to exceed 20 years), reduced by an annuity (offset) based on a hypothetical account that is credited with 6% of the participant s annual base salary and bonus paid each year and investment returns as defined in the SERP. Participants are fully vested in their benefits after five years of plan participation or age 65, whichever is earlier. If a vested participant retires prior to age 65, then the monthly retirement benefit as described above (before reduction for the offset) will be reduced by 5% for each year that retirement precedes age 65. In the event a participant is terminated for cause before becoming vested in his or her benefits, all benefits under the SERP will be forfeited. In general, benefits will be paid when the participant retires from the company or beginning at age 65. However, in the event of a change of control (as defined in the plan), the benefit will be paid as a lump-sum if a participant s employment is terminated by us without cause or the participant resigns for good reason within two years following a change of control. All benefits become fully vested upon a change of control whether or not a participant s employment is terminated.

NOTE 5 Related Party Transactions

Employment Agreements with Executives

On January 18, 2006, we entered into an employment agreement with Robert T. Ray in connection with Mr. Ray s appointment as Senior Vice President and Chief Financial Officer of our company and, on March 27, 2006, we entered into an employment agreement with Carolyn M. Campbell in connection with Ms. Campbell s appointment as Senior Vice President and General Counsel of our company.

In addition to the agreements with Mr. Ray and Ms. Campbell, we have employment agreements in place with all of our other executive officers. These agreements have an initial term of three years, which is automatically extended each year for an additional year on the anniversary of the effective date, unless either party gives notice to the contrary within 90 days prior to such anniversary of the effective date. Executive officers receive annual salary and bonus payments pursuant to their employment agreements which are subject to review each year by our Compensation Committee. Payment of the bonus is based on achievement of certain performance goals established each year by our

Compensation Committee. In

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addition, executive officers are eligible to participate in our stock compensation, deferred compensation and supplemental executive retirement plans.

If we terminate an executive without cause (as defined in the 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), 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 medical and insurance benefits for a specified time period. The agreements further provide that if any payments made to the executive, whether or not under the agreement, would result in an excise tax being imposed on the executive 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 without financial obligation (other than payment of any accrued obligations). Each executive may terminate his or her agreement at any time and 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 will automatically vest and any other conditions to such awards will be deemed satisfied.

The terms of Mr. Ray s and Ms. Campbell s employment agreements are consistent with the general terms described above. Further, Mr. Ray receives an initial annual base salary of $315,000 and is entitled to an annual incentive bonus equal to 55% of his base salary. Ms. Campbell receives an initial annual base salary of $275,000 and is entitled to an annual incentive bonus equal to 55% of her salary. In addition, Mr. Ray received a signing bonus in the amount of $85,000, together with 7,500 restricted shares of our common stock and options to purchase 20,000 shares of our common stock at $53.72 per share. Ms. Campbell received 5,000 restricted shares of our common stock and options to purchase 15,000 shares of our common stock at an exercise price of $50.41 per share. The agreements provide for an automobile allowance of $700 per month and reimbursement of certain business expenses and require us to provide certain disability and life insurance. If we terminate Mr. Ray or Ms. Campbell without cause, or if either terminates their employment with us for good reason, we are obligated to pay each a lump sum severance payment as described above. Based on initial compensation levels, Mr. Ray s lump sum payment would equal approximately $1.5 million and Ms. Campbell s would equal approximately $1.3 million.

NOTE 6 Acquisitions and Dispositions

Sale of Texas Gulf of Mexico Assets

On March 31, 2006, we completed the sale of the Texas portion of our Gulf of Mexico assets. Pursuant to the purchase and sale agreement dated February 28, 2006 between us, as seller, and various partnerships affiliated with Merit Energy Company, as buyer, the gross sale price was $220 million. The net cash proceeds received from the sale of these assets totaled approximately $190.8 million after various customary closing items, including the preliminary adjustment for operations related to the properties after January 1, 2006, the effective date of the transactions. Of the total net proceeds, approximately $140.1 million was received for assets acquired by various partnerships affiliated with Merit Energy Company. In addition, approximately $43.1 million and $7.6 million were received from Hydro Gulf of Mexico, L.L.C. and Nippon Oil Exploration U.S.A. Ltd., respectively, pursuant to the exercise of their preferential rights to acquire certain working interests offered for sale. The Texas portion of our Gulf of Mexico assets accounted for approximately 18% of our 2005 production and represented an estimated 58.5 Bcfe, or 7% of our total proved reserves at December 31, 2005. Of the $190.8 million in net cash proceeds received from the sale of our Texas Gulf of Mexico assets, we used $158 million to repay and reduce outstanding borrowings under our revolving credit facility, deposited $9.5 million with a qualified intermediary for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code, and used substantially all of the $23.3 million balance for working capital purposes. In accordance with full cost accounting, no gain or loss was recognized on the sale. The net proceeds of $190.8 million were recorded as a reduction to the full cost pool.

Sale of Louisiana Gulf of Mexico Assets

On June 1, 2006, we completed the sale of substantially all of our Louisiana Gulf of Mexico assets for a gross sale price of $590 million. The sale of a substantial majority of these assets to various partnerships affiliated with Merit Energy Company was completed on May 31, 2006 pursuant to a purchase and sale agreement dated April 7, 2006, and the sale of certain working interests to Nippon Oil Exploration U.S.A. Ltd. and Chevron USA Inc. was completed on June 1, 2006

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pursuant to the exercise of preferential purchase rights. The aggregate net cash proceeds received from the sale of these assets totaled approximately $530.8 million after customary closing items, including the preliminary adjustment for operations related to the properties after January 1, 2006, the effective date of the transactions. Of the total net proceeds, approximately $510.2 million was received from various partnerships affiliated with Merit Energy Company, and approximately $16.6 million and $4.0 million was received from Nippon Oil Exploration U.S.A. Ltd. and Chevron USA Inc., respectively.

At December 31, 2005, proved reserves associated with these assets were estimated at 186.1 Bcfe, and production associated with these assets accounted for approximately 22% of our 2005 production and 21% of our production during the first three months of 2006. The sale transactions did not include 18 Louisiana offshore blocks retained by us. Of these 18 blocks, 16 are undeveloped and two had exploratory wells in progress during the first six months of 2006.

Of the $530.8 million in net cash proceeds received from the sale of the Louisiana portion of our Gulf of Mexico assets, $314.2 million was deposited directly with qualified intermediaries for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code, and substantially all of the $216.6 million balance, associated with properties sold outside the like-kind exchange arrangement, was used to reduce outstanding borrowings under our revolving credit facility. In accordance with full cost accounting, no gain or loss was recognized on the sale. The net proceeds of $530.8 million were recorded as a reduction to the full cost pool.

The sale of certain of our Gulf of Mexico properties accelerated the payment of a net profits interest to the predecessor owner of properties acquired by us in October 2003, for which we have accrued an estimated $30 million as of June 30, 2006 (see Note 7 Subsequent Events *Payment of Gulf of Mexico Net Profits Interest*).

East Texas Acquisition

On April 25, 2006, we completed the acquisition of certain interests in natural gas and oil producing properties, together with acreage located in the Willow Springs Field of Gregg County, Texas, from Samson Lone Star Limited Partnership. The net purchase price of $21.3 million was paid in cash and funded in part by cash on hand of $19.1 million and borrowings under our bank credit facility of $2.2 million. The $22.0 million gross purchase price was reduced by $0.7 million for various customary closing items, including an adjustment for operations related to the properties after the effective date of the transaction, January 1, 2006. The properties cover approximately 4,237 gross (3,579 net) acres, are adjacent to our existing operations in the Willow Springs Field and include interests in 28 producing wells with an average working interest of 80%. Based on internal estimates, total proved reserves associated with the interests acquired were approximately 16.2 Bcfe as of January 1, 2006.

NOTE 7 Subsequent Events

Payment of Gulf of Mexico Net Profits Interest

On August 1, 2006, we paid approximately $21 million to the predecessor owner of certain of our Gulf of Mexico properties in connection with a net profits interest payment that was accelerated by the completion of the sale of our Louisiana Gulf of Mexico assets on June 1, 2006 (see Note 6 Acquisitions and Dispositions *Sale of Louisiana Gulf of Mexico Assets*). The $21 million was paid in cash and funded with borrowings under our revolving credit facility. The final settlement and payment, if any, is expected to be determined by the end of the third quarter of 2006.

Liquidation of Derivative Contracts

On August 4, 2006, we liquidated and settled open derivative contracts representing 20,000 MMBtu per day of hedged production for each of the months September and October 2006. The cost to unwind and settle these contracts was approximately $0.9 million. After unwinding these contracts, our weighted average open derivative position for the remaining months of 2006 (July through December) decreased from 190,000 MMBtu per day to 183,333 MMBtu per day, which is approximately 83% of forecasted equivalent natural gas and oil production for the six-month period ending December 31, 2006.

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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 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, as amended, for the year ended December 31, 2005.

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 actual results, including future production, revenues and expenses, to differ materially from our expectations. See Forward-Looking Statements at the beginning of this Quarterly Report, Item 1A. Risk Factors in our Annual Report on Form 10-K, as amended, for the year ended December 31, 2005, and Item 1A. Risk Factors in Part II of our Quarterly Report on Form 10-Q for the period ended March 31, 2006 and this Quarterly Report for additional discussion of risks affecting our business.

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. We were founded in December 1985 as a Delaware corporation and wholly-owned subsidiary of our then parent company, KeySpan Corporation. We completed our initial public offering in September 1996. Through three separate transactions, the last of which occurred in November 2004, KeySpan completely divested of its ownership in the common stock of the company.

At June 30, 2006, we had operations in four producing regions within the United States: South Texas; the Arkoma Basin of Arkansas and Oklahoma; East Texas; and the Uinta and DJ Basins in the Rocky Mountains. On June 1, 2006, we completed the sale of substantially all of our Gulf of Mexico assets (see Note 6 Acquisitions and Dispositions). Our total net proved reserves as of December 31, 2005 were 861 billion cubic feet equivalent, or Bcfe, with onshore reserves totaling 616 Bcfe. Our reserves are fully engineered on an annual basis by independent petroleum engineers. Approximately 64% of our proved reserves at December 31, 2005 were classified as proved developed.

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. Because natural gas accounts for approximately 95% of our production, 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 have historically utilized derivative instruments to hedge future sales prices on a significant portion of our natural gas production. Our use of derivative instruments prevented us from realizing the full benefit of the strong natural gas price environment during the first half of 2006 and in each of the preceding three years, and may continue to do so in future periods. Our natural gas revenues may experience significant volatility in future periods as all of our open derivative contracts ceased to qualify for hedge accounting during the first quarter of 2006 (see Note 1 Summary of Organization and Significant Accounting Policies *Derivative Instruments and Hedging Activities*).

Segment reporting is not applicable for us, as all of our assets are based in North America and each of our operating areas has similar economic characteristics and each meets the criteria for aggregation as defined in SFAS 131, Disclosures about Segments of an Enterprise and Related Information.

Strategic Restructuring Plan

In November 2005, we announced our strategic restructuring plan, the primary purpose of which is to enhance shareholder value by becoming a pure onshore operator. We believe the strategic shift toward focusing our operations onshore will leverage our strength of developing complex, tight or low permeability natural gas reservoirs and provide flexibility to expand both in our present core onshore areas and other tight gas basins, positioning us to benefit from opportunities that might arise in connection with acquisition or consolidation transactions. We also anticipate that focusing our efforts onshore will provide a more stable and predictable production and reserve growth profile, improve our overall reserve-to production ratio, and result in lower finding and development costs. We believe our existing onshore portfolio offers a multi-year inventory of drilling opportunities, and that we can continue to realize the benefits of scale by operating the majority of our properties and maintaining a high working interest.

As of the end of the second quarter of 2006, we had achieved significant milestones towards our restructuring objectives, including the completion of the sale of substantially all of our Gulf of Mexico assets for net cash proceeds of $721.6 million. Of the $721.6 million in net cash proceeds, we used $374.0 million to repay and reduce borrowings on our revolving credit facility; deposited $323.7 million with qualified intermediaries for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code; and used the balance of $23.9 million for working capital purposes. In addition, in May 2006, we began repurchasing our common stock under our previously announced

$200 million share repurchase authorization. As of the date of this Quarterly Report, we had repurchased and retired 1,176,500 shares, or approximately 4% of our outstanding common stock, for approximately $61.6 million. Finally, in June 2006, we liquidated open hedge positions totaling 60,000 MMBtu per day for each of the remaining six months of 2006 at a cost of $14.3 million.

On June 12, 2006, we received an unsolicited proposal from JANA Partners LLC, a hedge fund, to acquire our company for $62 per share. According to its public filings, JANA Partners beneficially owned approximately 12.3% of our outstanding common stock as of the date of the proposal. On June 26, 2006, we announced our Board of Directors determination that the unsolicited proposal made by JANA Partners was not in the best interest of our shareholders and that we had engaged Lehman Brothers Inc. to assist us in exploring a broad range of strategic alternatives to further enhance shareholder value. These alternatives may complement or replace the continued execution of our previously announced business plan and include, but are not limited to, a recapitalization of our company either through additional share repurchases or a special dividend; operating partnerships and / or strategic alliances; and the sale or merger of the company. In conjunction with the ongoing exploration of strategic alternatives, we will continue to focus on the redeployment of the net sales proceeds of our offshore assets into a variety of opportunities, each aimed at enhancing shareholder value. These opportunities may include onshore acquisitions, additional debt repayments and up to an additional $138.4 million in discretionary stock repurchases under our current $200 million share repurchase authorization.

Disposition of Gulf of Mexico Assets. On March 31, 2006, we completed the sale of the Texas portion of our Gulf of Mexico assets. The $220 million gross sale price was adjusted by $29.2 million for various customary closing items, including the preliminary adjustment for operations related to the properties after January 1, 2006, the effective date of the transaction. Of the $190.8 million in net cash proceeds, approximately $140.1 million was received for assets sold to various partnerships affiliated with Merit Energy Company. In addition, approximately $43.1 million and $7.6 million were received from Hydro Gulf of Mexico, L.L.C. and Nippon Oil Exploration U.S.A. Ltd., respectively, pursuant to the exercise of their preferential purchase rights. We used $158 million of the net cash proceeds received from the sale of these assets to repay and reduce outstanding borrowings under our revolving credit facility; deposited $9.5 million of the proceeds with a qualified intermediary for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code; and used substantially all of the $23.3 million balance for working capital purposes.

On June 1, 2006, we completed the sale of substantially all of our Louisiana Gulf of Mexico assets for a gross purchase price of $590 million. The sale of a substantial majority of these assets to various partnerships affiliated with Merit Energy Company was completed on May 31, 2006 pursuant to a purchase and sale agreement dated April 7, 2006, and the sale of certain working interests to Nippon Oil Exploration U.S.A. Ltd. and Chevron USA Inc. was completed on June 1, 2006 pursuant to the exercise of preferential purchase rights. The aggregate net cash proceeds received from the sale of these assets totaled approximately $530.8 million after customary closing items, including the preliminary adjustment for operations related to the properties after January 1, 2006, the effective date of the transactions. Of the total net proceeds, approximately $510.2 million was received for assets acquired by the Merit affiliates, and approximately $16.6 million and $4.0 million was received from Nippon Oil Exploration U.S.A. Ltd. and Chevron USA Inc., respectively.

Of the $530.8 million in net cash proceeds received from the sale of the Louisiana portion of our Gulf of Mexico assets, $314.2 million was deposited directly with qualified intermediaries for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code, and substantially all of the $216.6 million balance, associated with properties sold outside the like-kind exchange arrangement, was used to reduce outstanding borrowings under our revolving credit facility.

The sale of certain of our Gulf of Mexico properties accelerated the payment of a net profits interest to the predecessor owner of properties acquired by us in October 2003, which, as of June 30, 2006 was estimated at $30 million. On August 1, 2006, we paid approximately $21 million in connection with the net profits interest, which we funded with borrowings under our revolving credit facility (see Note 7 Subsequent Events *Payment of Gulf of Mexico Net Profits Interest*). The final settlement and payment, if any, is expected to be determined by the end of the third quarter of 2006.

The sale transactions did not include 18 Louisiana offshore blocks, which we retained. Of these 18 blocks, 16 are undeveloped and two have exploratory wells currently in progress.

Redeployment of Net Sales Proceeds. Subject to our ongoing exploration of strategic alternatives, we intend to pursue a balanced and disciplined approach to the redeployment of net proceeds from the sale of our Gulf of Mexico assets. Specifically, we intend to pursue a variety of reinvestment alternatives, each designed to facilitate our continued growth and further enhance shareholder value. These opportunities may include additional share repurchases, a special dividend, operating partnerships, strategic alliances, the development of our existing onshore assets, the pursuit of additional opportunities onshore and the repayment of debt, as well as the sale or merger of the company. We expect to be disciplined in our approach, targeting only those opportunities that deliver clear strategic and financial benefits as measured by our internal rate of return and accretion metrics.

At June 30, 2006, $323.7 million of the proceeds of the sale of our Gulf of Mexico assets were held in escrow with qualified intermediaries to permit reinvestment in natural gas and oil properties in a manner that qualifies as a like-kind exchange under Section 1031 of the Internal Revenue Code. As our offshore assets accounted for 27% of our production during the first six months of 2006 and 40% of our production during 2005 and represented approximately 245 Bcfe, or 28% of our proved reserves, at December 31, 2005, our operating revenues and cash flows have decreased and are expected to remain below prior year levels given the sale of these offshore assets. There can be no assurance that we will elect to or be able to replace this sold production with the acquisition of new properties on attractive terms, as market conditions, the availability of suitable properties, our evaluation of other strategic alternatives, inherent acquisition risks and other uncertainties may not allow for the reinvestment of all of the proceeds within the prescribed time period for the most tax-efficient results or at all.

Our ability to identify onshore properties that warrant investment and consummate their acquisition should position our onshore business for growth. However, our desire or ability to pursue any such opportunities is subject to a number of factors, many of which are beyond our control. Accordingly, we cannot ensure that any such opportunities will be available to us, nor can we predict with any degree of certainty the impact of any such opportunities or any strategic alternatives on our financial condition, results of operations or cash flows.

Hedging Strategy. In connection with the June 1, 2006 completion of the divestiture of our Gulf of Mexico assets, we were required under our revolving credit facility to liquidate a portion of our 2006 hedge position. In order to comply with this requirement, in June 2006, we liquidated and settled open contracts representing 60,000 MMBtu per day of hedged production for each of the months July through December 2006. The cost to unwind and settle these contracts was approximately $14.3 million. After unwinding these contracts, our weighted average open derivative position for the remaining months of 2006 (July through December) decreased from 250,000 MMBtu per day to 190,000 MMBtu per day. In addition, on August 4, 2006, we liquidated and settled open derivative contracts representing 20,000 MMBtu per day of hedged production for each of the months September and October 2006. The cost to unwind and settle these contracts was approximately $0.9 million (see Note 7 Subsequent Events *Liquidation of Derivative Contracts*). After unwinding these contracts, our weighted average open derivative position for the remaining months of 2006 (July through December) decreased from 190,000 MMBtu per day to 183,333 MMBtu per day, which is approximately 83% of forecasted equivalent natural gas and oil production for the six-month period ending December 31, 2006. We currently have open derivative positions covering 30,000 MMBtu per day for 2007 and 20,000 MMBtu per day for 2008. Based on our current projections, we anticipate that the 30,000 MMBtu per day for 2007 will approximate 12% of our expected equivalent production rate at December 31, 2006. Based on the current commodity price environment, we do not expect to enter into additional derivative contracts at this time. However, we continue to evaluate opportunities to hedge our basis differential and may elect to hedge a portion of that exposure if market conditions warrant. In addition, if we believe market conditions are favorable, we may elect to unwind an additional 20,000 MMBtu per day for the months November and December 2006.

Recent Acquisition

On April 25, 2006, we completed the acquisition of certain interests in natural gas and oil producing properties and acreage in the Willow Springs Field of Gregg County, located in East Texas, from Samson Lone Star Limited Partnership. The $22 million cash purchase price was reduced by $0.7 million to $21.3 million for various customary closing items, including an adjustment for operations related to the properties after the effective date of the transaction, January 1, 2006. The properties cover approximately 4,237 gross (3,579 net) acres, are adjacent to our existing operations in the Willow Springs Field and include interests in 28 producing wells with an average working interest of 80%. Based on internal estimates, total proved reserves associated with the interests acquired were 16.2 Bcfe as of January 1, 2006. The acquisition was funded with cash on hand of $19.1 million and borrowings under our revolving credit facility of $2.2 million.

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

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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 Annual Report for the year ended December 31, 2005, as amended.

Recent Accounting Pronouncements

In July 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement 109 (FIN 48) , which clarifies the accounting for uncertainty in tax positions taken or expected to be taken in a tax return, including issues relating to financial statement recognition and measurement. FIN 48 provides that the tax effects from an uncertain tax position can be recognized in the financial statements only if the position is more-likely-than-not to be sustained if the position were to be challenged by a taxing authority. The assessment of the tax position is based solely on the technical merits of the position, without regard to the likelihood that the tax position may be challenged. If an uncertain tax position meets the more-likely-than-not threshold, the largest amount of tax benefit that is more than 50 percent likely to be recognized upon ultimate settlement with the taxing authority, is recorded. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. We are currently evaluating the impact of adopting FIN 48 on our financial statements

Overview of Results for the Second Quarter of 2006

During the second quarter of 2006, we continued to implement our restructuring plan to focus our operations primarily onshore. Completion of the sale of our Texas offshore properties on March 31, 2006 and our Louisiana offshore properties on June 1, 2006 had a significant impact on our operating results for the second quarter of 2006. Our total production volume for the second quarter of 2006 was 23% lower than first quarter 2006 and 27% lower than the second quarter of 2005 due primarily to the sale of our Gulf of Mexico assets combined with continued hurricane-related curtailments of certain offshore Louisiana fields prior to the completion of their sale on June 1, 2006. We expect that production volume, natural gas revenues and operating income will be lower unless and until we are able to replace the production generated from the Gulf of Mexico assets sold. In addition to lower production volume, we experienced lower operating expenses during the second quarter of 2006 as a result of the sale of our offshore assets. Natural gas prices during the second quarter of 2006 continued to decline from the record highs in the fourth quarter of 2005 primarily as a result of mild winter and spring weather combined with an increase in natural gas in U.S. storage. As a result of the lower natural gas prices, our cash losses from hedging activities improved significantly from the prior two quarters.

Our results of operations for the second quarter of 2006 include production, revenues and expenses relating to the Louisiana Gulf of Mexico properties until completion of the sale transactions on June 1, 2006. The sale of our Gulf of Mexico assets had a significant impact on our operating results for the second quarter of 2006 and on the comparability of those results quarter-over-quarter. During the second quarter of 2006:

§ We generated $23.4 million in net income, a decrease of 47% from $43.8 million in the second quarter 2005;

§ We produced approximately 22 Bcfe, and our average daily production rate was 239 MMcfe per day compared to 312 MMcfe per day during the first quarter of 2006 and 328 MMcfe per day during the second quarter of 2005, a 23% decrease from the previous quarter and a 27% decrease from a year ago;

§ We generated $133.0 million cash flows from operating activities compared to $123.8 million generated during the second quarter of 2005, an increase of 7%;

§ We invested $193.1 million in natural gas and oil properties, which included $21.3 million for the acquisition of producing properties and acreage with an estimated 16.2 Bcfe of proved reserves located in the Willow Springs Field of Gregg County, adjacent to our existing East Texas operations (see Note 6 Acquisitions and Dispositions *East Texas Acquisition*) and an estimated $30 million accrued for the payment of a net profits interest to the predecessor owner of certain Gulf of Mexico properties that was accelerated by the sale (see Note 6 Acquisitions and Dispositions *Sale of Louisiana Gulf of Mexico Assets* and Note 7 Subsequent Events

Payment of Gulf of Mexico Net Profits Interest);

§ We deposited $323.7 million in proceeds from the sale of our Gulf of Mexico assets with qualified intermediaries for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code;

§ We decreased net borrowings under our revolving credit facility by $149 million during the second quarter of 2006 and by $322 million during the first six months of 2006, using a portion of the net proceeds from the sale of our Gulf of Mexico assets;

§ We paid $14.3 million to liquidate and settle derivative contracts covering 60,000 MMBtu per day for each of the months July through December 2006, reducing our volume hedged from 250,000 MMBtu per day to 190,000

MMBtu per day for each of the remaining six months of 2006 as required by our revolving credit facility in connection with our Gulf of Mexico sale;

§ We commenced share repurchases under our previously announced $200 million stock repurchase authorization in May 2006, and during May and June 2006, we repurchased 1,176,500 shares, or approximately 4% of our outstanding common stock, in the open market for approximately $61.6 million, funded with cash on hand and borrowings under our revolving credit facility;

§ We drilled 85 wells, of which 78, or 92%, were successful, with one offshore, six in East Texas, 23 in South Texas, 16 in Arkoma and 32 in the Rockies;

§ In South Texas, we added an eighth drilling rig and began drilling on the properties acquired in November 2005;

§ In the Rockies, we began to process seismic data and identify drilling locations on leased acreage in the DJ Basin covered by the 150 square mile 3D seismic survey completed during the first quarter of 2006 and continued to bring new wells on-line;

§ Effective June 1, 2006 and in connection with the completion of the sale of the Louisiana portion of our Gulf of Mexico assets, the borrowing base on our revolving credit facility was reduced by $50 million, from $550 million to $500 million, and as a result of this reduction, we wrote-off unamortized loan costs of $0.6 million;

§ On June 12, 2006, we received an unsolicited proposal from JANA Partners LLC to acquire our company for $62 per share; and

§ On June 26, 2006, we announced our Board of Directors determination that the unsolicited proposal made by JANA Partners was not in the best interest of our shareholders and that Lehman Brothers Inc. had been engaged to assist us in exploring a broad range of strategic alternatives to further enhance shareholder value.

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Operating and Financial Results for the Three Month and Six Month Periods Ended June 30, 2006 Compared to the Three Month and Six Month Periods Ended June 30, 2005.

Our operating results for the three-month and six-month periods ended June 30, 2006, include production, revenues and expenses relating to our Texas Gulf of Mexico properties until the completion of their sale on March 31, 2006 and our Louisiana Gulf of Mexico properties until the completion of their sale on June 1, 2006. The sale of our Gulf of Mexico assets had a significant impact on operating results for both the three-month and six-month periods ended June 30, 2006 and on the comparability of those results both quarter-over-quarter and period-over-period.

	Three Months Ended June 30,				Six Months Ended June 30,			
	2006	**2005**	**$ change**	**%**	**2006**	**2005**	**$ change**	**%**
	(in thousands, except prices and percentages)							
Natural gas revenues	$129,785	$181,054	$(51,269)	-28%	$328,290	$345,023	$(16,733)	-5%
Oil revenues	15,167	18,805	(3,638)	-19%	35,620	35,925	(305)	-1%
Gain (loss) on settled derivatives	(18,424)	(24,335)	5,911	-24%	(64,949)	(38,510)	(26,439)	69%
Unrealized gain (loss) derivatives	17,285		17,285	100%	21,871	(1,424)	23,295	100%
Operating revenues	145,914	175,817	(29,903)	-17%	323,518	341,537	(18,019)	-5%
Operating expenses	93,353	106,117	(12,764)	-12%	217,789	210,236	7,553	4%
Income from operations	52,561	69,700	(17,139)	-25%	105,729	131,301	(25,572)	-19%
Net income	23,371	43,830	(20,459)	-47%	53,143	77,268	(24,125)	-31%
Production:								
Natural gas (MMcf)	20,244	27,440	(7,196)	-26%	46,267	54,797	(8,530)	-16%
Oil (MBbls)	257	406	(149)	-37%	605	812	(207)	-25%
Total (MMcfe) [1]	21,786	29,876	(8,090)	-27%	49,897	59,669	(9,772)	-16%
Average daily production (MMcfe/d)	239	328	(89)	-27%	276	330	(54)	-16%
Average Sales Prices:								
Natural Gas (per Mcf) unhedged	$ 6.41	$ 6.60	$ (0.19)	-3%	$ 7.10	$ 6.30	$ 0.80	13%
Natural Gas (per Mcf) realized [2]	5.50	5.71	(0.21)	-4%	5.69	5.59	0.10	2%
Natural Gas (per Mcf) all-in [3]	6.35	5.71	0.64	11%	6.16	5.57	0.60	11%
Oil (per Bbl) realized	59.02	46.32	12.70	27%	58.88	44.24	14.63	33%

(1) MMcfe is defined as one million cubic feet equivalent of natural gas, determined

using the ratio of six MMcf of natural gas to one MBbl of crude oil, condensate or natural gas liquids.

(2) Average prices include gains and losses realized on derivative contracts settled during the period.

(3) Average prices include both the effect of gains and losses realized on derivative contracts settled during the period as well as unrealized gains and losses recognized pursuant to accounting under SFAS 133.

Income from Operations

Operating revenues, expenses and income were all lower during the second quarter of 2006 as compared to the second quarter of 2005 as a result of the sale of our offshore producing assets combined with continued hurricane-related curtailments of certain offshore Louisiana fields prior to completion of their sale on June 1, 2006. Production from the Gulf of Mexico assets sold accounted for approximately 42% of our total production and 45% of our natural gas and oil revenues before hedging activities during the second quarter of 2005.

For the first six months of 2006, the sale of our offshore assets had less of an impact, as the sale of the Texas portion of these assets was not completed until March 31, 2006 and the sale of the Louisiana portion was not completed until June 1, 2006. Operating revenues decreased to $18.0 million, or 5% lower during the first six months of 2006 as compared to the first six months of 2005, primarily as a result of a 16% decline in equivalent production volumes due primarily to the sale of our offshore producing assets, offset in part by an 11% increase in our average all-in natural gas price. While higher market prices for natural gas during the first six months of 2006 caused our losses from hedging activities to increase from the first six months of 2005, our losses from hedging activities narrowed considerably over the last two consecutive quarters due to the decline in natural gas prices from the record highs seen during the fourth quarter of 2005. Income from operations for the first six months of 2006 decreased by $25.6 million, or 19%, as compared to the first six months of 2005,

as operating expenses increased by 4% due primarily to rising service costs and higher severance tax rates, offset in part by lower depreciation, depletion and amortization expense.

Production Volume

As a result of the sale of the Texas portion of our offshore assets on March 31, 2006 and the Louisiana portion of our offshore assets on June 1, 2006, combined with continued hurricane-related curtailments from certain Louisiana fields, total company production volumes were 27% lower during the second quarter of 2006 compared to the second quarter of 2005 and 16% lower for the first six months of 2006 as compared to the first six months of 2005. The following table provides a comparison of average daily production by area:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2006	**2005**	**change**	**%**	**2006**	**2005**	**change**	**%**
	(MMcfe per day)				(MMcfe per day)			
South Texas	142	139	3	2%	143	137	6	4%
Arkoma	39	41	(2)	-5%	40	42	(2)	-5%
East Texas	10	4	6	150%	11	3	8	267%
Rockies	6	4	2	50%	6	5	1	20%
Other	1	1			1	1		
Total onshore	198	189	9	5%	201	188	13	7%
Offshore	41	139	(98)	-71%	75	142	(67)	-47%
Total company	239	328	(89)	-27%	276	330	(54)	-16%

Onshore. For the second quarter of 2006, daily production rates increased by 9 MMcfe per day, or 5%, from an average of 189 MMcfe per day during the second quarter of 2005 to an average of 198 MMcfe per day during the second quarter of 2006. For the first six months of 2006, onshore production increased by 13 MMcfe per day, or 7% from the first six months of 2005.

In South Texas, production increased quarter-over-quarter and period-over-period, primarily from the production added by the properties acquired in November 2005 from Kerr-McGee and Westport. In Arkoma, average daily production declined approximately 2 MMcfe per day, or 5% during the second quarter and the first half of 2006, due in part to a partial curtailment of our drilling activity late in the third quarter of 2005 as one of our drilling rigs left the field for repair, combined with curtailments during the second quarter of 2006 caused by over supply in the gathering system. In January 2006, the Arkoma rig returned to the field, where we currently have three rigs drilling. In East Texas, production is up over 100% from prior year levels, with an increase of 6 MMcfe per day for the second quarter of 2006 and 8 MMcfe per day for the first six months of 2006. The increase in East Texas production is due to our acquisition of acreage and producing wells during 2005 combined with the drilling program initiated in the second quarter of 2005 that added 16 new producing wells during 2005. This successful acquisition and development drilling program continued into the first half of 2006 with the acquisition of approximately 28 producing wells in the Willow Springs field in April 2006 and the successful drilling of 12 new wells. However, our East Texas production was curtailed during the second quarter of 2006 due to compression and pipeline issues. In the Rockies, we continue to add production and connect completed wells to sales as average daily production rates increased by 50% quarter-over-quarter and 20% period-over-period. However, high pressure in the Uinta pipeline caused curtailments during the second quarter of 2006.

Offshore. Production for the second quarter of 2006 includes offshore production from our Louisiana Gulf of Mexico assets during April and May, as the sale of these assets was completed June 1, 2006. Offshore production for the first six months of 2006 includes production from our Louisiana Gulf of Mexico during the first five months of 2006 and production from our Texas Gulf of Mexico assets for the first three months of 2006 as the sale of the Texas assets was completed on March 31, 2006. During both the three-month and six-month periods ended June 30, 2006, offshore production was lower than prior year rates due primarily to continued curtailments from Louisiana fields subsequent to Hurricanes Katrina and Rita during August and September 2005.

Commodity Prices and Effects of Hedging

During the fourth quarter of 2005 and the first quarter of 2006, a portion of our derivative contracts became ineffective as hedges. In conjunction with our entry into an agreement on February 28, 2006 to sell our Texas Gulf of Mexico assets, forecasted production volume attributable to these properties was deemed no longer available to cover open hedge positions and, because of the method we utilized to allocate hedged production, the remaining portion of all our open derivative contracts that previously qualified for hedge accounting ceased to qualify for hedge accounting. As a result, applicable accounting guidelines precluded our use of hedge accounting for all open derivative contracts at the end of the first quarter

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of 2006. Accordingly, mark-to-market accounting is now utilized and all subsequent changes in the fair value of open derivative contracts are recognized as an increase or reduction to natural gas revenues.

The following table summarizes the components of our realized and unrealized gains and losses due to derivative contracts for the three-month and six-month periods ended June 30, 2006 and 2005. All amounts in the following table are shown on a pre-tax basis and are included in our statement of operations on the line item natural gas and oil revenues.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(in thousands)			
Cash (loss) realized on contracts settled [1]	$ (18,424)	$ (24,335)	$ (64,949)	$ (38,510)
Non-cash unrealized gain (loss):				
Ineffectiveness gain (loss)	16,110		31,900	(1,424)
Mark-to-market change in fair value gain (loss)	30,620		68,786	
Deferred loss prior quarter production shortfalls			(20,600)	
Recognition of all deferred losses relating to Gulf of Mexico production sold during period	(29,445)		(58,215)	
Total non-cash unrealized gain (loss)	17,285		21,871	(1,424)
Total gain (loss) from hedging activities	$ (1,139)	$ (24,335)	$ (43,078)	$ (39,934)

(1) Includes $14.3 million paid during the second quarter of 2006 to liquidate and settle contracts covering 60,000 MMBtu per day for each of the months July through December 2006. This liquidation and settlement was made in connection with the completion of the sale of our Gulf of Mexico assets on June 1, 2006 and was required under

the terms of our revolving credit facility.

For the three months ended June 30, 2006, our average unhedged sales price for natural gas decreased by 3% from $6.60 per Mcf during the second quarter of 2005 to $6.41 per Mcf during the second quarter of 2006. Because of the decrease in the market price for natural gas, our hedge positions were more effective and our total loss from hedging activities decreased by $23.2 million quarter-over-quarter. Included in natural gas revenues for the second quarter of 2006 is a net loss of $1.1 million from natural gas hedging activities, which is comprised of a realized loss of $18.4 million relating to contracts settled during the period and a net unrealized gain of $17.3 million as a result of accounting under SFAS 133. The $18.4 million realized loss during the second quarter of 2006 includes $14.3 million paid in connection with the completion of the sale of our Gulf of Mexico assets to liquidate and settle contracts totaling 60,000 MMBtu per day for each of the months July through December 2006. As a result of the cash loss from derivative contracts settled during the second quarter of 2006, we realized an average natural gas price during the quarter of $5.50 per Mcf, which was 14% lower than our average unhedged sales price of $6.41 per Mcf for the 2006 quarter. During the second quarter of 2005, we incurred a total loss from hedging activities of $24.3 million, which represented only realized losses on derivative contracts settled during the quarter, with no unrealized gains or losses due to ineffectiveness of our open contracts accounted for as cash flow hedges under SFAS 133. As a result of the cash loss from hedge contracts settled during the second quarter of 2005, we realized an average price of $5.71 per Mcf, which was 13% lower than our average unhedged sales price of $6.60 per Mcf for the 2005 quarter.

For the six months ended June 30, 2006, our average unhedged sales price for natural gas increased by 13% from $6.30 per Mcf during the first six months of 2005 to $7.10 per Mcf during the first six months of 2006. Our total loss from hedging activities increased by $3.1 million during the first six months of 2006 as compared to the first six months of 2005. Included in natural gas revenues for the first six months of 2006 is a net loss of $43.1 million from natural gas hedging activities, which includes a realized loss of $64.9 million relating to contracts settled during the six-month period and a net unrealized gain of $21.9 million as a result of accounting under SFAS 133. As a result of the cash loss from derivative contracts settled during the first six months of 2006, we realized an average natural gas price during the quarter of $5.69 per Mcf, which was 20% lower than our average unhedged sales price for the first six months of $7.10 per Mcf. During the corresponding six months of 2005, we incurred a total loss from hedging activities of $39.9 million, which includes realized losses on derivative contracts settled during the period of $38.5 million and an unrealized loss of $1.4 million due to ineffectiveness of our open contracts accounted for as cash flow hedges under SFAS 133. As a result of the cash loss from hedge contracts settled during the first six months of 2005, we realized an average price of $5.59 per Mcf, which was 11% lower than our average unhedged sales price for the first six months of 2005 of $6.30 per Mcf.

We may continue to experience volatility in our natural gas and oil revenues during future periods as mark-to-market accounting is utilized for all of our open derivative contracts.

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Operating Expenses

	Three Months Ended June 30,				Six Months Ended June 30,			
	2006	2005	$ change	%	2006	2005	$ change	%
				($ per MMcfe)				
Lease operating expense	$ 0.83	$ 0.64	$ 0.19	30%	$ 0.80	$ 0.58	$ 0.22	38%
Severance tax	0.22	0.15	0.07	47%	0.22	0.13	0.09	69%
Transportation expense	0.13	0.10	0.03	30%	0.11	0.10	0.01	10%
Asset retirement accretion expense	0.05	0.04	0.01	25%	0.05	0.04	0.01	25%
Depreciation, depletion and amortization	2.66	2.41	0.25	10%	2.84	2.39	0.45	19%
General and administrative, net	0.40	0.21	0.19	90%	0.35	0.29	0.06	21%
Total operating expenses per unit of production	$ 4.29	$ 3.55	$ 0.74	21%	$ 4.37	$ 3.53	$ 0.84	24%

Total operating expenses on an absolute dollar basis decreased 12% during the second quarter of 2006 as compared to the second quarter of 2005, primarily as a result of lower lease operating expense and depreciation, depletion and amortization expense subsequent to the sale of the Texas Gulf of Mexico assets on March 31, 2006 and the sale of the Louisiana Gulf of Mexico assets on May 31 and June 1, 2006. For the first six months of 2006, total operating expenses on an absolute dollar basis increased 4% from the first six months of 2005, primarily as a result of higher lease operating expenses and severance tax expense as we continued to expand our operations prior to the sale of our offshore assets. On a unit of production basis, operating expenses increased $0.74 per Mcfe, or 21%, quarter-over-quarter and $0.84 per Mcfe, or 24% period-over-period. Per unit expenses were higher for all categories of operating expense for both the three-month and the six-month periods ended June 30, 2006 due to a higher level of operating expenses combined with a lower level of production due in part to the sale of our offshore producing assets and continued curtailment of production from these assets during the first five months of 2006 due to Hurricanes Katrina and Rita.

Lease Operating Expense. On an absolute dollar basis, lease operating expense decreased by 6% for the second quarter of 2006 as compared to the second quarter of 2005 and increased by 16% for the first six months of 2006 as compared to the first six months of 2005. The quarter-over-quarter decrease is a result of the disposition of our offshore assets, the Texas portion of which closed on March 31, 2006 and the Louisiana portion of which closed on June 1, 2006, offset in part by additional expense of $1.9 million during the second quarter of 2006 as a result of a cumulative adjustment for a net profits interest in the Rincon Field, located in South Texas that was acquired in November 2005. The increase in lease operating expense for the first six months of 2006 relates primarily to the continued upward pressure on service costs, labor, materials, insurance and property taxes resulting from the sustained strength of commodity prices driving increased activity levels across the industry, combined with the continued expansion of our operating base from acquisitions and the escalation of our onshore drilling program prior to the sale of our offshore assets.

Severance Tax. Severance tax is a function of volumes and revenues generated from onshore production. During the second quarter of 2006, severance tax expense increased by 7% on an absolute dollar basis and by $0.07 per Mcfe on a unit of production basis from the second quarter 2005. During the first six months of 2006, severance tax expense increased by 47% on an absolute dollar basis and by $0.09 on a unit of production basis from the first six months of 2005. These absolute dollar and per unit rate increases reflect higher commodity prices, an increase in severance tax rates and an increase in onshore production both quarter-over-quarter and period-over-period, due in part to the South

Texas properties acquired in November 2005. We expect our severance tax per unit of production to increase considerably now that we have sold all our offshore producing assets.

Depreciation, Depletion and Amortization. The decrease in our depreciation, depletion and amortization expense for the both the three-month and six-month periods ended June 30, 2006 as compared to the corresponding periods of 2005 was primarily a result of lower production volume subsequent to the sale of our offshore producing assets, offset in part by higher depletion rates during 2006. Our depreciation, depletion and amortization rate for the second quarter of 2006 was $2.66 per Mcfe, or 10% higher than the $2.41 per Mcfe during the second quarter of 2005. For the first six months of 2006, our depreciation, depletion and amortization rate of $2.84 per Mcfe was $0.45 per Mcfe or 19% higher than our depreciation, depletion and amortization rate of $2.39 per Mcfe during the first six months of 2005. The higher rates during the three-month and six-month periods ended June 30, 2006 compared to corresponding periods of 2005 are a result of the increases in both our finding and future development costs.

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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,				Six Months Ended June 30,			
	2006	2005	$ change	%	2006	2005	$ change	%
	(in thousands)							
Gross general and administrative expense	$ 15,008	$ 10,516	$ 4,492	43%	$ 29,406	$ 26,478	$ 2,928	11%
Operating overhead reimbursements	(583)	(525)	(58)	11%	(1,181)	(1,075)	(106)	10%
Capitalized general and administrative	(5,720)	(3,791)	(1,929)	51%	(10,914)	(8,080)	(2,834)	35%
General and administrative expense, net	$ 8,705	$ 6,200	$ 2,505	40%	$ 17,311	$ 17,323	$ (12)	

Gross and net general and administrative expenses were higher during the second quarter of 2006 and the first six months of 2006 as compared to the corresponding three-month and six-month periods of 2005 due to increases in salaries, benefits and incentive compensation expenses, stock compensation expense, legal and consulting fees and office rent and utilities. In addition, during the second quarter of 2006 we incurred additional expenses of approximately $1.7 million, which included approximately $1.3 million in bonuses paid to certain employees in connection with the completion of the sale of our Gulf of Mexico assets and approximately $0.4 million in severance payments to certain employees in our offshore group who were terminated following the sale of the assets. During the first six months of 2005 we incurred additional expenses of approximately $5.0 million pursuant to the February 2005 renegotiation of executive employment agreements. Excluding the $5.0 million in additional expenses incurred during the first six months of 2005 and the additional $1.7 million for special bonuses and severance payments to offshore employees during the second quarter of 2006, gross general and administrative expenses would reflect an increase of $6.2 million, or 29%, and net general and administrative expenses would reflect an increase of $4.7 million, or 38%, for the first six months of 2006. Capitalized general and administrative expense increased during the second quarter of 2006 and the first six months of 2006 as a result of the increase in salaries, benefits and incentive compensation expenses for our technical workforce.

	Unit of Production - Mcfe							
	Three Months Ended June 30,				Six Months Ended June 30,			
General and Administrative Expense	2006	2005	Variance		2006	2005	Variance	
	($ per MMcfe)							
Gross general and administrative expense	$ 0.69	$ 0.35	$ 0.34	97%	$ 0.59	$ 0.44	$ 0.15	34%
Operating overhead reimbursements	(0.03)	(0.02)	(0.01)	50%	(0.02)	(0.02)		
Capitalized general and administrative	(0.26)	(0.12)	(0.14)	117%	(0.22)	(0.13)	(0.09)	69%
General and administrative expense, net	$ 0.40	$ 0.21	$ 0.19	90%	$ 0.35	$ 0.29	$ 0.06	21%

On a per-unit of production basis, both gross and net general and administrative expenses were higher during the three-month and six-month periods of 2006 and reflect the increase in gross general and administrative expense and the decrease in production volume resulting primarily from the sale of our offshore assets. The additional $1.7 million in special bonuses and severance expense incurred during the second quarter of 2006 in connection with the completion of the sale of our offshore assets contributed $0.08 to the increase in gross general and administrative expense per-unit for the second quarter of 2006 and $0.03 per Mcfe of the increase for the first six months of 2006. The additional $5.0 million in employment contract renegotiation expenses incurred during the first quarter of 2005 accounted for $0.08 of gross and net general and administrative expenses per-unit of production for the first six months of 2005. We expect that general and administrative expenses on a per-unit of production basis will be higher in future periods unless and until we are able to replace the production from the assets sold.

Other Income and Expense, Interest and Taxes

Other Income and Expense. For the second quarter of 2006 and 2005, other income and expense is comprised of income of $0.8 million and $1.0 million, respectively, related to refunds of prior years severance tax expense. For the first six months of 2006, other income and expense includes $2.2 million related to refunds of prior years severance tax expense. For the first six months of 2005 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%. Refunds of prior years severance tax expense relate to our July 2002 application and receipt from the Railroad Commission of Texas of 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.

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Interest Expense, Net of Capitalized Interest

Interest and Average Borrowings	Three Months Ended June 30, 2006	2005	Variance		Six Months Ended June 30, 2006	2005	Variance	
	(dollars in thousands)							
Gross interest	$ 7,451	$ 5,621	$ 1,830	33%	$ 17,827	$ 11,045	$ 6,782	61%
Capitalized interest	(1,000)	(2,425)	1,425	59%	(2,655)	(4,415)	1,760	40%
Interest expense, net of capitalized interest	$ 6,451	$ 3,196	$ 3,255	102%	$ 15,172	$ 6,630	$ 8,542	129%
Average total borrowings (1)	$ 371,000	$ 346,000	$ 25,000	7%	$ 494,000	$ 345,000	$ 149,000	43%
Average total interest rate (1)	6.97%	6.04%	0.93%	15%	6.66%	5.94%	0.72%	12%
Average bank borrowings	$ 196,000	$ 171,000	$ 25,000	15%	$ 319,000	$ 170,000	$ 149,000	88%
Average bank interest rate	7.02%	5.13%	1.89%	37%	6.50%	4.88%	1.62%	33%

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

For both the three-month and six-month periods ended June 30, 2006, 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. In addition, gross interest expense for the three-month and six-month periods ended June 30, 2006 includes an additional $0.6 million for debt extinguishment incurred in connection with the decrease in the borrowing base of our revolving credit facility upon completion of the Gulf of Mexico asset sale transactions. Our average bank debt increased after the first quarter of 2005 and through the end of the first quarter of 2006 as we utilized bank borrowings to fund acquisitions in East Texas and South Texas and to settle obligations under derivative contracts. Using a portion of the proceeds from the sale of our Gulf of Mexico assets, we reduced bank borrowings by a net $322 million during the first six months of 2006 to an outstanding balance of $100 million at June 30, 2006. Although the majority of our bank debt bears interest at LIBOR-based rates, the Federal Reserve raised rates by one quarter of a percent eight times during 2005 and four times during the first six months of 2006. We expect to continue to see an increase in the average interest rates on our bank debt if the Federal Reserve continues to increase interest rates. Capitalized interest is a function of unevaluated properties, and decreased significantly by 59% during the second quarter of 2006 and by 40% during the first six months of 2006 as compared to the corresponding three-month and six-month periods of 2005. The decrease corresponds directly to the decrease in the balance of our unevaluated properties, of which approximately $75.8 million related to our Gulf of Mexico assets sold during the first

six months of 2006. We expect our capitalized interest to be lower and our net interest expense to be proportionally higher with the shift in our operating focus onshore. We expect our unevaluated property balance to be lower given the lower cost structure of onshore projects and the shorter timeline to complete the evaluation of onshore projects.
Income Tax Provision. Our provision for taxes includes both state and federal taxes. In May 2006, the State of Texas enacted substantial changes to its tax structure beginning in 2007 by implementing a new margin tax of 1% to be imposed on revenues less certain costs, as specified in the legislation. During the second quarter of 2006, we increased our provision by an additional $6.8 million to provide for deferred taxes to the State of Texas under the newly enacted state margin tax.

Liquidity

Capital Requirements

Our principal requirements for capital are to fund our planned exploration, development and acquisition activities and to satisfy our contractual obligations, primarily including the repayment of debt and any amounts owing during the period relating to our derivative contracts, as well as repurchases of common stock from time to time. Our principal uses of capital include the following:

§ Drilling and completing new natural gas and oil wells;

§ Constructing and installing new production infrastructure;

§ Acquiring additional reserves and producing properties;

§ Acquiring and maintaining our lease acreage position and our seismic resources;

§ Maintaining, repairing, and enhancing existing natural gas and oil wells;

- § Plugging and abandoning depleted or uneconomic natural gas and oil wells; and
- § Indirect costs related to our exploration activities, including payroll and other expenses attributable to our exploration professional staff.

During the six months ended June 30, 2006, we spent approximately $266.6 million on these and other capital activities. 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. See Note 4 Commitments and Contingencies *Drilling Contracts*. As the year progresses, we will continue to evaluate our capital spending. Actual spending levels may vary due to a variety of factors, including drilling results, natural gas prices, economic conditions, any future acquisitions and the outcome of our Board s review of strategic alternatives, as well as the impact of the market price of our common stock on any repurchases.

Future Commitments

The following table provides estimates of the timing of future payments that we were obligated to make based on agreements in place at June 30, 2006. All amounts listed in the following table are categorized as liabilities on our balance sheet with the exception of lease payments for operating leases, obligations under long-term drilling contracts and outstanding letters of credit issued for performance obligations. At June 30, 2006, we did not have any capital leases. The table includes references to our financial statements for information regarding the listed obligation. Contractual obligations relating to our revolving credit facility and our senior notes include only payments of principal.

In addition to the contractual obligations listed on the following table, our balance sheet at June 30, 2006 reflects accrued interest payable on our revolving credit facility of approximately $0.4 million 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. As a result of credits and amounts on deposit that were paid during 2005, we do not expect to make any cash payments for federal income taxes during 2006 and expect to pay less than $1.0 million for state income taxes.

			Future Commitments Payments Due by Period			
	Reference	Total	1 year or less	2 3 years	4 5 years	after 5 years
			(in thousands)			
Contractual Obligations:						
Revolving credit facility, due November 2010	Note 2	$ 100,000	$	$	$ 100,000	$
7% senior subordinated notes, due June 2013	Note 2	175,000				175,000
Derivative instruments	Note 1	81,093	44,165	36,928		
Gulf of Mexico net profits payment	Note 6	30,000	30,000			
Operating leases	Note 4	5,930	949	3,848	1,133	
Letters of credit	Note 4	300	300			
Drilling contracts	Note 4	17,613	12,943	4,670		
		409,936	88,357	45,446	101,133	175,000

Other Long-Term Obligations:						
Asset retirement obligations	Note 1	36,868				36,868
Supplemental Executive Retirement Plan	Note 4	2,229	100	265	261	1,603
		39,097	100	265	261	38,471
Total contractual obligations and Commitments:		$ 449,033	$ 88,457	$ 45,711	$ 101,394	$ 213,471

Capital Resources

We intend to fund our contractual commitments noted above, including any required settlement of derivative contracts, as well as our capital expenditure program, including any future acquisitions in excess of the escrowed proceeds from the Gulf of Mexico asset sales, with cash flows from our operations and borrowings under our revolving credit facility. In addition, subject to the outcome of the ongoing review of strategic alternatives described above (see Strategic Restructuring Plan above), we expect to use the remaining proceeds from the sale of our Gulf of Mexico assets for one or more of the following purposes: additional share repurchases, a special dividend, operating partnerships, strategic alliances, developing our existing onshore assets, acquiring additional onshore assets, and/or repaying indebtedness.

Current Liquidity

The following table summarizes our total available liquidity at June 30, 2006 and December 31, 2005:

	June 30, 2006	December 31, 2005
	(in thousands)	
Revolving credit facility borrowing base	$ 500,000	$ 600,000
Outstanding borrowings	(100,000)	(422,000)
Letters of credit	(300)	(300)
Unused borrowing capacity	399,700	177,700
Cash and cash equivalents	3,488	7,979
Designated cash	323,675	
Total available liquidity	$ 726,863	$ 185,679

At June 30, 2006, we had $399.7 million of available borrowing capacity under our revolving credit facility. In addition, we had designated cash of $323.7 million, representing proceeds from the sale of substantially all of our Gulf of Mexico assets, deposited with qualified intermediaries for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code. If a significant acquisition opportunity arises, we may also choose to access the public capital markets to issue additional debt and/or equity securities. Our primary sources of cash during the first six months of 2006 were from funds generated from operations, bank borrowings and proceeds from the sale of substantially all of our Gulf of Mexico assets. Cash was used primarily to repay bank borrowings, fund exploration and development expenditures, repurchase common stock and fund the required settlements of derivative contracts. During the first six months of 2006, we made aggregate cash payments of $16.5 million for interest and no cash payments for taxes. The table below summarizes the sources and uses of cash for the six months ended June 30, 2006 and 2005:

	Six Months Ended June 30, 2006	2005	variance
		(in thousands)	
Net cash provided by operating activities	$ 253,307	$ 257,192	$ (3,885)
Net cash provided by (used in) investing activities	121,401	(254,671)	376,072
Net cash (used in) financing activities	(379,199)	(16,404)	(362,795)
Net (decrease) in cash	$ (4,491)	$ (13,883)	$ 9,392

At June 30, 2006, we had a working capital deficit of $55.8 million and long-term debt of $275 million. The working capital deficit at June 30, 2006 was due in part to a $30 million accrual for the payment of a net profits interest to the predecessor owner of properties acquired by us in October 2003 that was accelerated upon the completion of the sale of our Gulf of Mexico assets and a current liability of $44.2 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 $28.6 million. Due in part to the settlement of open contracts during the first six months of 2006 and in part to a decline in the market price for natural gas from December 31, 2005 to June 30, 2006, the fair value of our open derivative contracts payable within the next 12 months decreased by $308.3 million, from a liability of $352.5 million at December 31, 2005 to a liability of $44.2 million at June 30, 2006. Corresponding to the decrease in the current derivative liability, the deferred tax asset associated with our derivative contracts decreased by $97.5 million during the same six-month period. NYMEX prices declined considerably during the first six months of 2006 from a closing price of $11.431 per MMBtu for the January 2006 contract to $5.887 per MMBtu for the July 2006 contract. 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 a larger unfavorable mark-to-market position in a higher 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 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 decreased by $3.9 million, or 2%, during the first six months of 2006. The decrease was primarily a result of the 19% decrease in operating income during the first six months of 2006 as compared to the first six months of 2005. 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. During the first six months of 2006, we realized slightly higher commodity prices but experienced lower production volumes due primarily to the sale of our Gulf of Mexico assets combined with continued hurricane-related curtailments from offshore Louisiana fields prior to their sale, and incurred higher operating expenses compared to the same six-month period of 2005.

Investing Activities. Total company capital expenditures during the first six months of 2006 were $315.0 million, which excludes $36.4 million of accrued and unpaid exploration and development costs. During the first six months of 2006, we spent $35.5 million, or 13%, more than we spent during the first six months of 2005, on natural gas and oil capital expenditures, of which $30 million relates to the accrual for an estimated net profits interest payment accelerated by the sale of certain offshore assets. During the first six months of 2006, we invested a net $313.9 million in natural gas and oil properties and we spent $1.1 million for non-oil and gas property and equipment. Non-oil and gas property and equipment includes expenditures for the expansion of Houston office lease space, and upgrades to our information technology systems and office equipment and compares to $0.5 million spent during the first six months of 2005. During the first six months of 2006, we spent 73% of our total natural gas and oil expenditures of $313.9 million onshore and 23% offshore with the balance of 4% on capitalized interest and general and administrative costs. We completed the drilling of 158 gross wells (125.8 net), of which 91%, or 144 (115.3 net), were successful and 14 (10.5 net) were unsuccessful, with an additional 40 wells (23.7 net) in progress at June 30, 2006, which includes one offshore exploratory well that we are participating in at West Cameron 132. All wells drilled during the first six months of 2006 were drilled onshore, with the exception of one offshore dry hole that we participated in at Eugene Island 357 and a second offshore well that we elected to participate in at West Cameron 39 that was successful. For the first six months of 2006, investing activities includes net proceeds from the sale of assets totaling $723.6 million, of which we used $374 million to repay borrowings under our revolving credit facility and deposited $323.7 with qualified intermediaries for potential reinvestment in like-kind exchange transactions under Section 1031 of the Internal Revenue Code, with the $23.9 million balance used for working capital purposes.

	Natural Gas and Oil Expenditures and Dispositions			
	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2006	**2005**	**2006**	**2005**
	(in thousands)			
Producing property acquisitions [1]	$ 51,336	$ 9,017	$ 47,245	$ 31,632
Leasehold and lease acquisition costs [2]	9,087	10,338	27,966	35,574
Development	105,344	74,981	192,656	147,403
Exploration	27,387	37,739	46,020	63,778
Total natural gas and oil capital expenditures	193,154	132,075	313,887	278,387
Producing property dispositions [3]	(534,278)		(723,649)	(150)
Net natural gas and oil capital expenditures	$ (341,124)	$ 132,075	$ (409,762)	$ 278,237

(1) For the three months ended June 30, 2006, includes the following: (i) $21.3 million paid for producing properties in East Texas in April 2006; and

(ii) $30 million representing the accrual for an estimated net profits interest payment to the predecessor owner of certain offshore properties acquired by us in October 2003, of which approximately $21 million was paid on August 1, 2006, with the final settlement and payment, if any, expected by the end of the third quarter of 2006. For the six months ended June 30, 2006, includes the above mentioned transactions and a final purchase price adjustment and return of capital of $4.1 million representing a reduction to the $159.0 net purchase price paid for the South Texas properties acquired on November 30, 2005 from Kerr-McGee Oil & Gas Onshore LP and Westport Oil and Gas

Company, L.P.

(2) For the three months ended June 30, 2006 and 2005, includes capitalized interest and general and administrative expenses of $6.7 million and $6.2 million, respectively. For the six months ended June 30, 2006 and 2005, includes capitalized interest and general and administrative expenses of $13.6 million and $12.5 million, respectively.

(3) For the three months ended June 30, 2006, includes net proceeds from the sale of our Louisiana Gulf of Mexico assets of $530.8 million, net of $4.4 million in fees associated with completion of the transaction, and $7.9 million in net proceeds for the sale of other assets. For the six months

ended June 30, 2006, includes proceeds from the above mentioned transactions in addition to net proceeds from the sale of the Texas portion of our Gulf of Mexico assets of $190.8 million, net of $1.5 million in transaction fees.

Financing Activities. During the first six months of 2006, total long-term debt decreased by a net $322 million as we used a portion of the proceeds received from the sale of our Gulf of Mexico assets to repay bank borrowings. In addition, under our previously announced $200 million stock repurchase authorization, we repurchased and retired 1,176,500 shares, or approximately 4% of our outstanding common stock, for approximately $61.6 million.

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Access to Capital Markets. We have the 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 effective shelf registration statements filed with the SEC in March and October 2004.

We believe that operating cash flow, designated cash balances and our credit facility will be adequate to meet our capital and operating requirements during the remaining six months of 2006. 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. Our revolving credit facility provides a lending commitment of $750 million with an additional $100 million available upon request and with prior approval from our lenders. Amounts available for borrowing under the credit facility are limited to a borrowing base, which effective June 1, 2006 was reduced to $500 million in connection with the completion of the sale of our Gulf of Mexico assets. In addition to utilizing operating cash flow, designated cash balances and borrowings under our revolving credit facility, we believe we could finance capital expenditures with issuances of additional debt or equity securities and/or via development arrangements with industry partners.

Subject to our ongoing review of strategic alternatives, we may reinvest a substantial portion of the remaining net cash proceeds from the sale of our Gulf of Mexico assets in longer-lived natural gas and oil assets onshore in North America. We plan to structure any potential reinvestment, where prudent, to optimize the tax effects under the like-kind exchange rules of Section 1031 of the Internal Revenue Code. However, numerous market conditions and uncertainties may not allow for the reinvestment of all of the proceeds within the prescribed time period for the most tax efficient treatment and to the extent we do not reinvest any such proceeds in a timely manner, we would then be required to pay the resulting tax liability.

Stock Repurchase Authorization. On November 4, 2005, our Board of Directors approved discretionary repurchases from time to time through November 4, 2006 of up to $200 million in company stock in conjunction with the divesture of all of our Gulf of Mexico assets. These purchases may be in the open market or in privately negotiated transactions, and are subject to a number of considerations, including market conditions for our shares, applicable legal requirements and contractual restrictions, available cash, competing reinvestment opportunities in the acquisition market for oil and gas assets and other factors. During the three months ended June 30, 2006, we repurchased 1,176,500 shares, or approximately 4% of our outstanding common stock, in the open market for a total cost of approximately $61.6 million. All repurchases were paid for in cash and funded with cash on hand or borrowings under our revolving credit facility. All repurchased shares were retired, and we expect to retire any shares that may be repurchased under this authorization in the future.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements.

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. The sales price of our production 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 Risk

At June 30, 2006, total debt was $275 million, of which approximately 64%, or $175 million, bears interest at a fixed interest rate of 7% per year. The remaining 36% of our total debt balance at June 30, 2006, or $100 million, represents our bank debt, which bears interest at floating or market interest rates that at our option are tied to prime rate or LIBOR. Fluctuations in market interest rates will cause our annual interest costs to fluctuate. During the first six months of 2006, the interest rate on our outstanding bank debt averaged 6.50% per year. If the balance of our bank debt at June 30, 2006 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 more predictable cash flows, 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 at the time we enter into a contract, all hedge structures meet the requirements for hedge 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 certain hedging arrangements limits the downside risk of adverse price movements, it also limits increases in future revenues as a result of favorable price movements, as has been the case in recent years, especially during the last four months of 2005 and continuing into the first half of 2006. In addition, because all of our open derivative contracts ceased to qualify for hedge accounting during the first quarter of 2006, our future earnings are expected to become more volatile as all subsequent changes in the fair market value of open contracts will be recognized as an increase or reduction to natural gas and oil revenues (see Note 1 Summary of Organization and Significant Accounting Policies *Derivative Instruments and Hedging Activities).*

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 typically use include swaps, collars and options, which we generally place with investment grade financial institutions that we believe present minimal credit risks. We believe that our credit risk related to our natural gas hedging instruments is no greater than the risk associated with the underlying primary contracts and that the elimination of price risk reduces volatility in our reported results of operations, financial position and cash flows from period to period and lowers our overall business risk. However, as a result of our hedging activities, we may be exposed to greater credit risk in the future.

Changes in Fair Value of Derivative Instruments

The following table summarizes the change in the fair value of our derivative instruments for each of the six-month periods from January 1 to June 30, 2006 and 2005, and provides the fair value at the end of each period.

	Six Months Ended June 30,	
	2006	**2005**
Change in Fair Value of Derivative Instruments:	Before Tax (in thousands)	
Fair value of contracts at January 1	$ (417,658)	$ (75,149)
Realized loss on contracts settled during period [1]	64,950	38,510
(Decrease) increase in fair value of all open contracts	271,615	(194,921)
Net change during period	336,565	(156,411)
Fair value of contracts outstanding at June 30	$ (81,093)	$ (231,560)

(1) Includes $14.3 million paid during the second quarter of 2006 to liquidate and settle contracts covering 60,000 MMBtu per day for each of the months July through December 2006. This liquidation and settlement was made in connection with

the completion of the sale of our Gulf of Mexico assets on June 1, 2006 and was required under the terms of our revolving credit facility.

Summary of Derivative Contracts

As of August 7, 2006, the following table summarizes, on a daily basis, our natural gas hedges for the second half of 2006 and for 2007 and 2008.

Year	Period (Months)	Transaction Type	Daily Volume (MMBtu/day)	NYMEX Price ($/MMBtu)	Floor Price ($/MMBtu)	Ceiling Price ($/MMBtu)
2006	Jul Dec	Swap	20,000	$ 5.87		
2006	Jul Dec	Swap	10,000	5.94		
2006	Jul Dec	Costless collar	10,000		$ 5.50	$ 7.20
2006	Jul Dec	Costless collar	20,000		5.50	7.26
2006	Jul Dec	Costless collar	20,000		5.75	7.20
2006	Jul Dec	Costless collar	50,000		5.82	7.00
2006	Jul Aug	Costless collar	30,000		6.00	7.00
2006	Sep Oct	Costless collar	10,000		6.00	7.00
2006	Nov Dec	Costless collar	30,000		6.00	7.00
2006	Jul Dec	Costless collar	20,000		6.00	7.02
2006	Jul Dec	Costless collar	10,000		6.00	7.05
2007	Jan Dec	Costless collar	20,000		$ 5.00	$ 6.50
2007	Jan Dec	Costless collar	10,000		5.00	6.79
2008	Jan Dec	Costless collar	20,000		$ 5.00	$ 5.72

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 market-based 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 prices.

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, 2006, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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Part II. Other Information

Item 1. Legal Proceedings

See Note 4 Commitments and Contingencies *Legal Proceedings* to the accompanying notes to consolidated financial statements for discussion of the material legal proceedings to which we are a party.

Item 1A. Risk Factors

As of August 8, 2006, except as noted below, there have been no material changes for the risk factors previously disclosed in Item 1A. Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2005, as amended, and in Item 1A. of Part II of our Quarterly Report on Form 10-Q for the quarter ended March 31, 2006. The previously disclosed risk factors are supplemented as follows:

Our exploration of strategic alternatives is subject to a number of uncertainties and may or may not result in any transactions.

In June 2006, we announced that we had engaged Lehman Brothers Inc. to assist the company in exploring a broad range of strategic alternatives in order to enhance shareholder value, including, among others, a recapitalization of the company through additional share repurchases or a special dividend, operating partnerships or strategic alliances and the sale or merger of the company. These alternatives may complement or replace the continued execution of our previously announced business plan. This process is ongoing and is subject to a number of risks and uncertainties, and there can be no assurance that the process will result in any transaction, or of the terms or timing of any transaction if one is ultimately undertaken. In addition, the process of evaluating strategic alternatives and implementing any course of action ultimately selected may distract our management team from their day-to-day responsibilities and could cause us to incur significant expenses. Any of these risks or uncertainties could adversely affect our business, stock price, financial condition, results of operations or cash flows.

Our ability to replace revenues generated from the sale of our Gulf of Mexico properties depends upon market conditions and numerous uncertainties.

Our recently sold offshore assets accounted for approximately 40% of our 2005 production and represented approximately 245 Bcfe, or 28% of our proved reserves, at December 31, 2005. Our operating revenues and cash flows have decreased and are expected to remain below prior year levels given the sale of these offshore assets. There can be no assurance that we will elect to or be able to replace this sold production with the acquisition of new properties on attractive terms, with tax-efficient results, or at all, as market conditions, the availability of suitable properties, our evaluation of other strategic alternatives, inherent acquisition risks and other uncertainties may impact our reinvestment of proceeds. If we are unable to timely consummate acquisitions that we believe warrant our investment, then we will be subject to a tax liability of approximately $87 million in connection with a tax gain on the sale of the Gulf of Mexico properties which would be payable in the fourth quarter of 2006.

Our hedging activities have resulted in financial losses and reduced our income and may continue to do so in the future.

By the end of the first quarter of 2006, all of our open derivative contracts ceased to qualify for hedge accounting. As a result, our future earnings are expected to become more volatile, as mark-to-market accounting will be utilized, and all subsequent changes in the fair market value of open contracts will be recognized as an increase or reduction to natural gas and oil revenues. At June 30, 2006, an unrealized loss of $64.4 million, net of tax, remains deferred in accumulated other comprehensive income. This loss represents the fixed value of our remaining open derivative contracts deferred in accumulated other comprehensive income at the time they ceased to qualify for hedge accounting. All remaining deferred losses will be reclassed and recognized in future earnings at the time when sale of the related forecasted natural gas production occurs. Over the next 12-month period, we expect to reclassify from accumulated other comprehensive income to earnings a loss of $52.1 million, net of tax, with $12.3 million to be recognized thereafter. However, these amounts could vary materially as a result of changes in market conditions.

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

The following table contains information about our purchases of equity securities during the second quarter of 2006.

Our Purchases of Our Common Stock

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[1]	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs ($ in thousands)
April 1 to April 30, 2006				$ 200,000
May 1 to May 31, 2006	766,800	$ 51.95	766,800	160,166
June 1 to June 30, 2006	409,700	$ 53.22	409,700	138,362
Total	1,176,500	$ 52.39	1,176,500	

(1) Repurchases during the second quarter of 2006 made pursuant to a $200 million share repurchase authorization announced on November 8, 2005, and in connection with the completion of the sale of our Gulf of Mexico assets. The $200 million share repurchase authorization expires November 1, 2006. See Note 3 Shareholders Equity *Stock Repurchase*

Authorization.

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

We held our Annual Meeting of Stockholders on April 28, 2006. A brief description of each matter voted upon at the meeting and the voting results thereof are set forth in Item 4 of Part II of our Quarterly Report on Form 10-Q for the period ended March 31, 2006 and incorporated herein by reference.

Item 6. Exhibits

EXHIBITS	DESCRIPTION
10.1	First Amendment to Amended and Restated Credit Agreement effective May 31, 2006 among The Houston Exploration Company and Wachovia Bank, National Association, as Issuing Bank and Administrative Agent; The Bank of Nova Scotia and Bank of America as Co-Syndication Agents; and BNP Paribas and Comerica Bank as Co-Documentation Agents
10.2(1)	Purchase and Sale Agreement dated April 7, 2006 between The Houston Exploration Company, as seller, and Merit Management Partners I, L.P., Merit Management Partners II, L.P., Merit Management Partners III, L.P., Merit Energy Partners III, L.P., Merit Energy Partners D-III, L.P., Merit Energy Partners E-III, L.P. and Merit Energy Partners F-III, L.P., collectively, as buyer (filed as Exhibit 99.1 to Current Report on Form 8-K dated June 2, 2006 (File No. 001-11899) and incorporated by reference).
10.3(1) (2)	The Houston Exploration Company Supplemental Executive Retirement Plan (Amended and Restated on July 25, 2006) (filed as Exhibit 10.1 to Current Report on Form 8-K dated July 31, 2006 (File No. 001-11899) and incorporated by reference).
10.4(1) (2)	Amendment No. 2 to The Houston Exploration Company Executive Deferred Compensation Plan (filed as Exhibit 10.2 to Current Report on Form 8-K dated July 31, 2006 (File No. 001-11899) and incorporated by reference).
10.5(1) (2)	The Houston Exploration Company 2005 Executive Deferred Compensation Plan (filed as Exhibit 10.3 to Current Report on Form 8-K dated July 31, 2006 (File No. 001-11899) and incorporated by reference).
10.6(1) (2)	Amendment to The Houston Exploration Company Non-Employee Director Deferred Compensation Plan (filed as Exhibit 10.4 to Current Report on Form 8-K dated July 31, 2006 (File No. 001-11899) and incorporated by reference).
10.7(1) (2)	The Houston Exploration Company Post-2004, AJCA Compliant Deferred Compensation Plan for Non-Employee Directors effective April 26, 2005 (filed as Exhibit 10.5 to Current Report on Form 8-K dated July 31, 2006 (File No. 001-11899) and incorporated by reference).
10.8 (2)	Form of Indemnification Agreement for Directors and Executive Officers.
10.9 (2)	Form of Non-Qualified Stock Option Agreement.
10.10 (2)	Form of Director Restricted Stock Award Agreement.
10.11 (2)	Form of Employee Restricted Stock Award Agreement.

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EXHIBITS	**DESCRIPTION**
12.1	Computation of ratio of earnings to fixed charges.
31.1	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Robert T. Ray, Chief Financial Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Robert T. Ray, Chief Financial Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(1) Previously filed.
(2) Identified as a management contract or compensation plan or arrangement.

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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
Date: August 8, 2006	By: /s/ William G. Hargett William G. Hargett Chairman, President and Chief Executive Officer
Date: August 8, 2006	By: /s/ Robert T. Ray Robert T. Ray Senior Vice President and Chief Financial Officer
Date: August 8, 2006	By: /s/ James F. Westmoreland James F. Westmoreland Vice President and Chief Accounting Officer

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