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

FORM 10-Q

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

For the quarterly period ended March 31, 2006

Commission file number 001-31539

ST. MARY LAND & EXPLORATION COMPANY
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**41-0518430** (I.R.S. Employer Identification No.)

1776 Lincoln Street, Suite 700, Denver, Colorado 80203
(Address of principal executive offices) (Zip Code)

(303) 861-8140
(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 ☒ No ☐

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. (Check one):

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the latest practicable date.

As of April 24, 2006, the registrant had 57,149,015 shares of common stock, $0.01 par value, outstanding.

ST. MARY LAND & EXPLORATION COMPANY

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PART I. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (UNAUDITED)
(In thousands, except share amounts)

	March 31, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 61,062	$ 14,925
Short-term investments	1,475	1,475
Accounts receivable	138,299	165,197
Prepaid expenses and other	6,866	7,283
Accrued derivative asset	24,512	6,799
Deferred income taxes	—	8,252
Total current assets	232,214	203,931
Property and equipment (successful efforts method), at cost:		
Proved oil and gas properties	1,522,508	1,441,959
Less - accumulated depletion, depreciation, and amortization	(529,855)	(497,621)
Unproved oil and gas properties, net of impairment allowance of $10,227 in 2006 and $9,862 in 2005	47,675	44,383
Wells in progress	59,403	55,505
Other property and equipment, net of accumulated depreciation of $8,462 in 2006 and $8,046 in 2005	5,855	5,340
	1,105,586	1,049,566
Noncurrent assets	15,884	15,250
Total Assets	**$ 1,353,684**	**$ 1,268,747**
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 160,909	$ 164,957
Accrued derivative liability	26,406	34,037
Deferred income taxes	1,759	—
Total current liabilities	189,074	198,994
Noncurrent liabilities:		
Convertible notes	99,909	99,885
Asset retirement obligation	67,196	66,078
Net Profits Plan liability	143,845	136,824
Deferred income taxes	138,085	128,296
Accrued derivative liability	75,425	64,137
Other noncurrent liabilities	5,995	5,213
Total noncurrent liabilities	530,455	500,433
Stockholders' equity:		
Common stock, $0.01 par value: authorized - 200,000,000 shares; issued: 57,222,306 shares in 2006 and 57,011,740 shares in 2005; outstanding, net of treasury shares: 56,972,306 shares in 2006 and 56,761,740 shares in 2005	572	570
Additional paid-in capital	125,329	123,278
Treasury stock, at cost: 250,000 shares in 2006 and 2005	(5,148)	(5,148)
Deferred stock-based compensation	—	(5,593)
Retained earnings	558,490	510,812
Accumulated other comprehensive loss	(45,088)	(54,599)
Total stockholders' equity	634,155	569,320
Total Liabilities and Stockholders' Equity	**$ 1,353,684**	**$ 1,268,747**

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)
(In thousands, except per share amounts)

	For the Three Months Ended March 31, 2006	2005
Operating revenues:		
Oil and gas production revenue	$ 184,065	$ 138,370
Oil and gas hedge gain	5,105	1,560
Marketed gas and other revenue	4,418	3,888
Total operating revenues	193,588	143,818
Operating expenses:		
Oil and gas production expense	41,214	32,159
Depletion, depreciation, amortization, and abandonment liability accretion	34,391	30,074
Exploration	10,787	7,083
Impairment of proved properties	1,289	—
Abandonment and impairment of unproved properties	1,186	1,870
General and administrative	10,786	5,986
Change in Net Profits Plan liability	7,021	4,221
Marketed gas system and other operating expense	6,228	4,768
Total operating expenses	112,902	86,161
Income from operations	80,686	57,657
Nonoperating income (expense):		
Interest income	824	82
Interest expense	(1,379)	(1,944)
Income before income taxes	80,131	55,795
Income tax expense	(29,605)	(20,692)
Net income	**$ 50,526**	**$ 35,103**
Basic weighted-average common shares outstanding	57,233	57,231
Diluted weighted-average common shares outstanding	67,334	67,047
Basic net income per common share	**$ 0.88**	**$ 0.61**
Diluted net income per common share	**$ 0.76**	**$ 0.54**

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (UNAUDITED)
(In thousands, except share amounts)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Treasury Stock Shares	Treasury Stock Amount	Deferred Stock-Based Compensation	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
Balances, December 31, 2004	**57,458,246**	**$ 574**	**$ 127,374**	**(500,000)**	**$ (5,295)**	**$ (5,039)**	**$ 364,567**	**$ 2,274**	**$ 484,455**
Comprehensive income, net of tax:									
Net income	—	—	—	—	—	—	151,936	—	151,936
Change in derivative instrument fair value	—	—	—	—	—	—	—	(71,522)	(71,522)
Reclassification to earnings	—	—	—	—	—	—	—	14,366	14,366
Minimum pension liability adjustment	—	—	—	—	—	—	—	283	283
Total comprehensive income									95,063
Cash dividends declared, $0.10 per share	—	—	—	—	—	—	(5,691)	—	(5,691)
Treasury stock purchases	—	—	—	(1,175,282)	(28,902)	—	—	—	(28,902)
Retirement of treasury stock	(1,411,356)	(14)	(28,729)	1,411,356	28,743	—	—	—	—
Issuance of common stock under Employee Stock Purchase Plan	28,447	—	601	—	—	—	—	—	601
Sale of common stock, including income tax benefit of stock option exercises	936,403	10	16,619	—	—	—	—	—	16,629

Deferred compensation related to issued restricted stock unit awards, net of forfeitures	—	—	3,404	—	—	(3,404)	—	—	—
Directors' stock compensation	—	—	—	13,926	306	(306)	—	—	—
Accrued stock-based compensation	—	—	4,009	—	—	—	—	—	4,009
Amortization of deferred stock-based compensation	—	—	—	—	—	3,156	—	—	3,156
Balances, December 31, 2005	**57,011,740**	**$ 570**	**$ 123,278**	**(250,000)**	**$ (5,148)**	**$ (5,593)**	**$ 510,812**	**$ (54,599)**	**$ 569,320**
Comprehensive income, net of tax:									
Net income	—	—	—	—	—	—	50,526	—	50,526
Change in derivative instrument fair value	—	—	—	—	—	—	—	12,730	12,730
Reclassification to earnings	—	—	—	—	—	—	—	(3,219)	(3,219)
Total comprehensive income									60,037
Cash dividends declared, $0.05 per share	—	—	—	—	—	—	(2,848)	—	(2,848)
Sale of common stock, including income tax benefit of stock option exercises	210,566	2	4,447	—	—	—	—	—	4,449
Adoption of Statement of Financial Accounting Standards No. 123R	—	—	(5,593)	—	—	5,593	—	—	—
Stock-based compensation expense	—	—	3,197	—	—	—	—	—	3,197
Balances, March 31, 2006	**57,222,306**	**$ 572**	**$ 125,329**	**(250,000)**	**$ (5,148)**	**$ —**	**$ 558,490**	**$ (45,088)**	**$ 634,155**

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)
(In thousands)

	For the Three Months Ended March 31, 2006	For the Three Months Ended March 31, 2005
Reconciliation of net income to net cash provided by operating activities:		
Net income	$ 50,526	$ 35,103
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation, amortization, and abandonment liability accretion	34,391	30,074
Exploratory dry hole expense	246	200
Impairment of proved properties	1,289	—
Abandonment and impairment of unproved properties	1,186	1,870
Unrealized derivative loss	470	1,129
Change in Net Profits Plan liability	7,021	4,221
Stock-based compensation expense	3,197	1,036
Income tax benefit from the exercise of stock options	—	1,225
Deferred income taxes	13,830	10,269
Other	133	1,046
Changes in current assets and liabilities:		
Accounts receivable	26,899	11,161
Prepaid expenses and other	416	(1,603)
Accounts payable and accrued expenses	(10,362)	(3,600)
Net cash provided by operating activities	**129,242**	**92,131**
Cash flows from investing activities:		
Proceeds from sale of oil and gas properties	—	45
Capital expenditures	(87,303)	(63,307)
Acquisition of oil and gas properties	(271)	(34,738)
Deposits to short-term investments available-for-sale	—	(1,502)
Receipts from short-term investments available-for-sale	—	1,402
Other	22	3,822
Net cash used in investing activities	**(87,552)**	**(94,278)**
Cash flows from financing activities:		
Proceeds from credit facility	—	66,967
Repayment of credit facility	—	(57,000)
Income tax benefit from the exercise of stock options	2,404	—
Proceeds from sale of common stock for exercise of stock options	2,043	3,282
Net cash provided by financing activities	**4,447**	**13,249**

Net change in cash and cash equivalents	46,137	11,102
Cash and cash equivalents at beginning of period	14,925	6,418
Cash and cash equivalents at end of period	**$ 61,062**	**$ 17,520**

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)
(Continued)

Supplemental schedule of additional cash flow information and noncash investing and financing activities:

	For the Three Months Ended March 31,	
	2006	2005
	(in thousands)	
Cash paid for interest, net of capitalized interest	$ 3,527	$ 3,549
Cash paid for income taxes	$ 9,832	$ 6,017

As of March 31, 2006 and 2005, $54.5 million and $37.0 million, respectively, are included as additions to oil and gas properties and as increases to accounts payable and accrued expenses. These oil and gas property additions are reflected in cash used in investing activities in the periods that the payables are settled.

In February 2006 and March 2005 the Company issued 484,351 and 195,312 restricted stock units, respectively, pursuant to the Company's restricted stock plan. The total expense associated with the issuances were $16.4 million and $4.5 million, respectively.

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

March 31, 2006

Note 1 – The Company and Business

St. Mary Land & Exploration Company ("St. Mary" or the "Company") is an independent energy company engaged in the exploration, exploitation, development, acquisition, and production of natural gas and crude oil. The Company's operations are conducted entirely in the Continental United States.

Note 2 - Basis of Presentation and Significant Accounting Policies

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements of St. Mary have been prepared in accordance with accounting principles generally accepted in the United States for interim financial information. They do not include all information and notes required by generally accepted accounting principles for complete financial statements. However, except as disclosed herein, there has been no material change in the information disclosed in the notes to consolidated financial statements included in St. Mary's Annual Report on Form 10-K for the year ended December 31, 2005. In the opinion of management, all adjustments (consisting of normal recurring accruals) considered necessary for a fair presentation of the interim financial information have been included. Operating results for the periods presented are not necessarily indicative of the results that may be expected for the full year.

Certain amounts in the 2005 unaudited condensed consolidated financial statements have been reclassified to conform to the 2006 unaudited condensed consolidated financial statement presentation.

Other Significant Accounting Policies

The accounting policies followed by the Company are set forth in Note 1 to the Company's consolidated financial statements in the Form 10-K for the year ended December 31, 2005, and are supplemented throughout the footnotes of this document It is suggested that these unaudited condensed consolidated financial statements be read in conjunction with the consolidated financial statements and notes included in the Form 10-K for the year ended December 31, 2005.

Note 3 – Acquisitions

Agate Acquisition

On January 5, 2005, the Company acquired Agate Petroleum, Inc. ("Agate") in exchange for $40.0 million in cash. The Company allocated the purchase price based on the estimated fair value of the acquired assets and liabilities. The Company acquired $4.6 million in cash from Agate, and the allocation of the purchase price resulted in recording $41.9 million to proved and unproved oil and gas properties, $1.1 million to net current liabilities, $9.5 million to goodwill, a deferred income tax liability of $13.5 million, and a $1.4 million asset retirement obligation.

Wold Acquisition

On August 1, 2005, the Company acquired oil and gas properties from Wold Oil Properties, Inc. ("Wold") for $37.1 million in cash. The Company allocated the purchase price based on the fair value of the acquired assets and liabilities. The allocation of the purchase price resulted in recording $43.9 million to proved and unproved oil and gas properties, a $7.0 million asset retirement obligation, and a net $232,000 to other assets.

There have been no significant acquisitions in 2006.

Note 4 – Earnings per Share

Basic net income per common share of stock is calculated by dividing net income available to common stockholders by the weighted-average basic common shares outstanding during each period. The shares represented by vested restricted stock units are included in the calculation of the weighted-average basic common shares outstanding. The earnings per share calculations reflect the impact of any repurchases of shares of common stock made by the Company.

Diluted net income per common share of stock is calculated by dividing adjusted net income by the weighted-average of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Adjusted net income is used for the if-converted method and is derived by adding interest expense paid on the Company's 5.75% Senior Convertible Notes due 2022 (the "Convertible Notes") back to net income and then adjusting for nondiscretionary items that are based on income and that would have changed had the Convertible Notes been converted at the beginning of the period. Potentially dilutive securities of the Company consist of in-the-money outstanding options to purchase the Company's common stock, shares into which the Convertible Notes may be converted and unvested restricted stock units.

The shares underlying the grants of restricted stock units are included in the diluted earnings per share calculation beginning with the grant date of units under the Restricted Stock Plan regardless of whether the shares are vested or unvested. Following the lapse of the restriction period, the shares underlying the units will be issued and therefore included in the number of issued and outstanding shares.

The dilutive effect of stock options and unvested restricted stock units is considered in the detailed calculation below. There were no anti-dilutive securities related to stock options for the three-month periods ended March 31, 2006 and 2005. There were no anti-dilutive securities related to restricted stock units for any periods presented.

Shares associated with the conversion feature of the Convertible Notes are accounted for using the if-converted method as described above and are considered in the detailed calculation below. A total of 7,692,307 potentially dilutive shares related to the Convertible Notes were included in the calculation of diluted net income per common share for the three-month periods ended March 31, 2006 and 2005. The Convertible Notes were issued in March 2002 and can be called by the Company in March 2007.

The following table sets forth the calculation of basic and diluted earnings per share:

	For the Three Months Ended March 31, 2006	2005
	(In thousands, except per share amounts)	
Net income	$ 50,526	$ 35,103
Adjustments to net income for dilution:		
Add: interest expense not incurred if Convertible Notes converted	1,563	1,563
Less: other adjustments	(16)	(16)
Less: income tax effect of adjustment items	(572)	(574)
Net income adjusted for the effect of dilution	$ 51,501	$ 36,076
Basic weighted-average common shares outstanding	57,233	57,231
Add: dilutive effects of stock options and unvested restricted stock units	2,409	2,124
Add: dilutive effect of Convertible Notes using if-converted method	7,692	7,692
Diluted weighted-average common shares outstanding	67,334	67,047
Basic net income per common share	$ 0.88	$ 0.61
Diluted net income per common share	$ 0.76	$ 0.54

Note 5 – Compensation Plans

Cash Bonus Plan

The Company has a cash bonus plan that allows participants to receive up to 50 percent of their aggregate base salary. Any awards under the cash bonus plan are based on a combination of Company and individual performance. The Company paid $7.4 million for cash bonuses in February 2006 related to the 2005 performance year and paid $2.0 million in March 2005 related to 2004 performance year. The cash bonus expense for the period ended March 31, 2006, was $1.1 million for the estimated value of bonuses expected to be paid in 2007 related to the 2006 performance year to date.

Net Profits Plan

Under the Company's Net Profits Interest Bonus Plan (the "Net Profits Plan"), oil and gas wells that are completed or acquired during a year are designated within a specific pool. Key employees designated as participants by the Company's Compensation Committee of the Board of Directors, upon recommendation by senior management, and employed by the Company on the last day of that year become entitled to bonus payments after the Company has received net cash flows returning 100 percent of all costs associated with that pool. Thereafter, ten percent of future net cash flows generated by the pool are allocated among the participants and distributed at least annually. The portion of net cash flows from the pool to be allocated among the participants increases to 20 percent after the Company has recovered 200 percent of the total costs for the pool, including payments made under the Net Profits Plan at the ten percent level. The Net Profits Plan has been in place since 1991. Pool years prior to and including 2005 are fully vested. Pool years beginning in 2006 will carry a vesting period of three years,

whereby one-third is vested at the end of the year for which participation is designated and one-third vests each of the following two anniversary dates. The maximum benefit to full participants from a particular year's pool will be limited to 300 percent of a participating individual's salary paid during the year to which the pool relates.

Expenses for distributions made or accrued under the Net Profits Plan related to current period operations for the three-month periods ended March 31, 2006, and 2005, were $6.9 million and $2.7 million, respectively. These amounts relate to the period realized results from oil and gas operations for the properties associated with the respective pools that have achieved payout status.

In a separate calculation, the Company records the estimated liability for future payments under the Net Profits Plan based on the discounted value of estimated future payments associated with each individual pool. The calculation of this liability is a significant management estimate utilizing a discount rate of predominately 15 percent, and is intended to represent the best estimate of the present value of expected future payments under the Net Profits Plan. The Company's estimate of its liability is highly dependent on the price assumptions and discount rates used in the calculations. The price assumptions are currently formulated by applying a price that is derived from a rolling average of actual prices realized together with adjusted NYMEX strip prices for the ensuing 12 months for a total of 36 months of data. This calculation is supplemented with hedge prices for the percentage of forecast production hedged. The forecast expense associated with this significant management estimate has been increasing as a result of the relatively strong oil and gas prices together with the impact of pricing that is assured to the Company as a result of its hedging program. In addition, these higher prices have moved more pools to payout status. The Company continually evaluates the assumptions used in this calculation in order to include the current market environment for oil and gas prices, discount rates, and overall market conditions. The calculation of the estimated liability for the Net Profits Plan is highly sensitive to price estimates and discount rate assumptions. For example, if the prices in the calculation were changed by ten percent, the liability recorded at March 31, 2006, would differ by approximately $31 million. A one percent change in the discount rate would result in a change of approximately $6 million. Actual cash payments to be made in future periods are dependent on realized actual production, prices, and costs associated with the individual pools of the Net Profits Plan. Consequently, actual cash payments will be inherently different from the amounts estimated.

The following table presents the changes in the estimated future liability attributable to the Net Profits Plan:

	For the Three Months Ended March 31,	
	2006	2005
	(In thousands)	
Liability balance for Net Profits Plan as of the beginning of the period	$ 136,824	$ 30,561
Increase in liability	13,902	6,886
Reduction in liability for cash payments made or accrued and recognized as compensation expense	(6,881)	(2,665)
Liability balance for Net Profits Plan as of the end of the period	$ 143,845	$ 34,782

The Company records changes in the present value of estimated future payments under the Net Profits Plan as a separate item in the consolidated statements of operations. The change in the estimated liability is recorded as an increase or decrease to expense in the current period. The amount recorded as an increase or decrease to expense associated with the change in the estimated liability is not allocated to general and administrative costs or exploration costs because it is an estimate at the current time of the

adjustment to the liability that is associated with the future net cash flows from oil and gas properties in the respective pools rather than current period realized performance. The table below presents the estimated allocation of the change in the liability if the Company did allocate the adjustment to these specific line items:

	For the Three Months Ended March 31,	
	2006	2005
	(In thousands)	
General and administrative expense	$ 3,196	$ 2,142
Exploration expense	3,825	2,079
Total	$ 7,021	$ 4,221

Stock Option Plans

The Company has a Stock Option Plan and an Incentive Stock Option Plan (collectively, the "Option Plans"). The last issuance of stock options was December 31, 2004. The Option Plans grant options to purchase shares of the Company's common stock to eligible employees, contractors, and current and former members of the Board of Directors. There are 11,200,000 shares of the Company's common stock reserved for issuance under the Option Plans as of March 31, 2006. This number is reduced to the extent that restricted stock or restricted stock units are granted under the Restricted Stock Plan. All options granted to date under the Option Plans have been granted at exercise prices equal to the respective market prices of the Company's common stock on the grant dates. All stock options granted under the Option Plans are exercisable for a period of up to ten years from the date of grant.

Prior to January 1, 2006, the Company accounted for its stock-based compensation plans under the recognition and measurement provisions of Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" ("APB Opinion No. 25") and related interpretations, as permitted by Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" ("SFAS No. 123"). Accordingly, no stock option compensation expense was recognized in the consolidated statements of operations prior to January 1, 2006, as all options granted under the Company's stock-based employee compensation plans had an exercise price equal to the market value of the underlying common stock on the date of grant.

Effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123R, "Share-Based Payment" ("SFAS No. 123R") using the modified prospective transition method. Under that transition method, compensation expense recognized in the three months ended March 31, 2006, includes: (a) compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006, based on the grant date fair value estimated in accordance with the original provisions of SFAS No. 123, and (b) compensation cost for all share-based payments granted subsequent to January 1, 2006, based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123R. During the quarter ended March 31, 2006, the Company recognized stock-based compensation expense of approximately $498,000 related to unvested stock options that were outstanding as of January 1, 2006. There was no material impact related to the cumulative effect of adoption related to SFAS No. 123R.

Prior to adopting SFAS No. 123R, all tax benefits resulting from the exercise of stock options were presented as operating cash flows in the statement of cash flows. SFAS No. 123R requires cash flows resulting from excess tax benefits to be classified as a part of cash flows from financing activities. Excess tax benefits are realized tax benefits from tax deductions for exercised options in excess of the deferred tax asset attributable to stock compensation costs for such options. As a result of adopting SFAS No. 123R, $2.4 million of excess tax benefits for the three months ended March 31, 2006, has been

classified as a financing cash inflow. Cash received from option exercises under all share-based payment arrangements for the three-month periods ended March 31, 2006 and

2005, was $2.0 million and $3.3 million, respectively.

The following table illustrates the effect on operating results and per share information had the Company accounted for share-based compensation in accordance with SFAS No. 123R for the period indicated:

	For the Three Months Ended March 31, 2005 (In thousands, except per share amounts)
Net Income	
As reported	$ 35,103
Add: Stock-based employee compensation expense included in reported net income, net of related income tax effects	652
Less: Stock-based employee compensation expense determined under fair value based method for all awards, net of related income tax effects	(1,165)
Pro forma net income	$ 34,590
Basic net income per share -	
As reported	$ 0.61
Pro forma	$ 0.60
Diluted net income per share -	
As reported	$ 0.54
Pro forma	$ 0.53

For purposes of these pro forma disclosures, the estimated fair value of the options and employee stock purchase plan grants are amortized to expense over the options' vesting periods. The effects of applying SFAS No. 123R in the pro forma disclosure are not necessarily indicative of actual future amounts.

The fair value of options and employee stock purchase plan grants has been measured at the date of grant using the Black-Scholes option-pricing model. No options were granted during the three-month periods ended March 31, 2006, and 2005. For the employee stock purchase plan offering period January 1, 2006, through June 30, 2006, the Company has expensed $49,000 based on the estimated fair value on the date of grant.

The following table summarizes the stock options outstanding as of March 31, 2006, as well as activity during the three months then ended:

	Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value (In thousands)
Outstanding at beginning of period	4,698,243	$ 12.21		
Exercised	(210,566)	9.70		
Outstanding at end of period	4,487,677	$ 12.32	6.04	$ 127,927
Exercisable at end of period	3,916,483	$ 12.20	5.89	$ 112,121

As of March 31, 2006, there was $1.7 million of total unrecognized compensation cost related to unvested stock option awards.

The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options that have no vesting restrictions and are fully transferable. In addition, option valuation models require the input of highly subjective assumptions including the expected stock price volatility. The Company's stock options have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, it is management's opinion that the valuations afforded by the existing models are different from the value that the options would realize if traded in the market.

Restricted Stock Plan

The Company has a long-term incentive program whereby grants of restricted stock or restricted stock units ("RSUs") may be awarded to eligible employees, consultants, and members of the Board of Directors. Restrictions and vesting periods for the awards are determined at the discretion of the Board of Directors and are set forth in the award agreements. Each RSU represents a right for one share of the Company's common stock to be delivered upon settlement of the award at the end of a specified period. The total number of shares of the Company's common stock reserved for issuance under the Restricted Stock Plan is 11,200,000 as of March 31, 2006. This number is reduced to the extent that stock options are granted under the Company's stock option plans.

St. Mary issued 484,351 RSUs on February 28, 2006, related to 2005 performance and 195,312 RSUs on March 15, 2005, related to 2004 performance. The total fair value associated with these issuances was $16.4 million in 2006 and $4.5 million in 2005 as measured on the respective grant dates. The granted RSUs vest 25 percent immediately upon grant and 25 percent on each of the next three anniversary dates of the grant. Compensation expense is recorded monthly over the vesting period of the award. The vested shares underlying the RSU grants will be issued on the third anniversary of the grant, at which time the shares carry no further restrictions. As of March 31, 2006, there was a total of 1,117,160 RSUs outstanding, of which 444,138 were vested. Total compensation expense related to the RSUs for the three-month periods ended March 31, 2006, and 2005, was $2.6 million and $1.0 million, respectively. The 2006 period includes $644,000 of compensation expense for the estimated value of grants expected to be issued in 2007 related to the 2006 performance year.

A summary of the status of nonvested RSUs as of March 31, 2006, and changes during the quarter then ended is presented below. There have been no forfeitures during the quarter ended March 31, 2006.

	Shares	Weighted-Average Grant-Date Fair Value
Nonvested, at beginning period	356,550	$ 18.92
Granted	484,351	$ 33.82

Vested	(167,879)	$ 30.77
Nonvested, at end of period	673,022	$ 26.68

In measuring expense from the grant of RSUs, SFAS No. 123R requires companies to estimate the fair value of the grant. The fair value of RSUs has been measured at the date of grant using the Black-Scholes option-pricing model. The fair value of the RSUs is inherently less than the market value of an unrestricted security; accordingly a fair value calculation is performed to determine the fair value of the grant. The Company's computation of expected volatility was based on historical volatility. The Company's computation of expected life was determined based on historical experience of similar awards, giving consideration to the contractual terms of the stock-based awards, vesting schedules and expectations of future employee behavior. The interest rate for periods within the contractual life of the award was based on the U.S. Treasury constant maturity yield at the time of grant. The fair values of RSUs granted were estimated using the following weighted-average assumptions:

	For the Three Months Ended March 31,	
	2006	2005
Risk free interest rate:	4.70%	4.03%
Dividend yield:	0.26%	0.40%
Volatility factor of the expected market price of the Company's common stock:	36.60%	26.70%
Expected life of the awards (in years)	3	3

Upon the adoption of SFAS No. 123R, the deferred compensation balance of $5,592,654 was reclassified to additional paid-in-capital. This deferred compensation balance had been recorded in accordance with APB Opinion No. 25. The Company had recorded compensation expense in periods prior to January 1, 2006, for restricted stock awards based on the intrinsic value on the date of grant. The intrinsic value was recorded as deferred compensation in a separate component of shareholders' equity and was expensed over the vesting period. SFAS No. 123R requires expense recognized subsequent to the adoption date to be based on fair value.

Note 6 - Income Taxes

Income tax expense for the three-month periods ended March 31, 2006 and 2005, differs from the amounts that would be provided by applying the statutory U.S. Federal income tax rate to income before income taxes primarily due to the effect of state income taxes, percentage depletion, the estimated effect of the domestic production activities deduction allowed in the American Jobs Creation Act of 2004, and other permanent differences.

For the three-month period ended March 31, 2006, the Company's current portion of income tax expense was $15.8 million, compared to $10.4 million for the three-month period ended March 31, 2005.

The Company's effective tax rate for the three-month period ended March 31, 2006, was 36.9 percent compared to 37.1 for the three-month period ended March 31, 2005. The change in tax rate reflects differences between the two quarters in the composition of the estimated highest marginal state tax rate as a result of acquisition and drilling activity. It also reflects differing effects from the Company's estimate of the effect of the domestic production activities deduction and the possible impact of state tax permanent differences.

Note 7 - Long-term Debt

Revolving Credit Facility

The Company executed an Amended and Restated Credit Agreement on April 7, 2005, to replace its previous credit facility. This credit facility specifies a maximum loan amount of $500 million and has a maturity date of April 7, 2010. Borrowings under the facility are secured by a pledge in favor of the lenders of collateral that includes certain oil and gas properties and the common stock of the material subsidiaries of the Company. The borrowing base under the credit facility as authorized by the bank group was limited to the face amount of the credit facility of $500 million, and is subject to regular semi-annual redeterminations. The borrowing base redetermination process considers the value of St. Mary's oil and gas properties and other assets, as determined by the bank syndicate. The Company has elected an aggregate commitment amount of $200 million under the credit facility. The Company must comply with certain financial and non-financial covenants. Interest and commitment fees are accrued based on the borrowing base utilization percentage table below. Euro-dollar loans accrue interest at LIBOR plus the applicable margin from the utilization table, and Alternative Base Rate (ABR) loans accrue interest at Prime plus the applicable margin from the utilization table. Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the consolidated statements of operations.

Borrowing base utilization percentage	<50%	≥50%<75%	≥75%<90%	≥90%
Euro-dollar loans	1.000%	1.250%	1.500%	1.750%
ABR loans	0.000%	0.250%	0.250%	0.500%
Commitment fee rate	0.250%	0.300%	0.375%	0.375%

The Company had no outstanding loans under its revolving credit agreement as of March 31, 2006.

5.75% Senior Convertible Notes Due 2022

As of March 31, 2006, the Company also had $100 million in outstanding borrowings under the Convertible Notes. The Convertible Notes provide for the payment of contingent interest of up to an additional 0.5 percent during six-month interest periods based on the note trading price before the beginning of the particular six-month period. Under that provision, interest was accrued at a total rate of 6.25 percent for the three-month periods ended March 31, 2006, and 2005. Based on the trading price of the Convertible Notes over the determination period, the Company will be subject to the contingent interest payments for the period from March 15, 2006, to September 14, 2006. The Company has the option to call the Convertible Notes in March 2007. By doing so, the Convertible Note holders will have the right to convert the Convertible Notes to shares at the current conversion price of $13 per share.

Weighted-average Interest Rate Paid

The weighted-average interest rates paid for the first quarters of 2006 and 2005 were 8.2 percent and 7.1 percent, respectively, including commitment fees paid on the unused portion of the credit facility aggregate commitment, amortization of deferred financing costs, amortization of the contingent interest embedded derivative, and the effects of interest rate swaps. The Company capitalized interest costs of $682,000 and $397,000 for the three-month periods ended March 31, 2006 and 2005, respectively.

Note 8 — Derivative Financial Instruments

The Company recognized a net gain of $4.4 million from its derivative contracts for the three months ended March 31, 2006, compared to a net gain of $459,000 for the three months ended March 31, 2005.

The following table summarizes derivative instrument gain (loss) activity (in thousands):

	For the Three Months Ended March 31, 2006	2005
Derivative contract settlements included in oil and gas hedge gain	$ 5,105	$ 1,560
Ineffective portion of hedges qualifying for hedge accounting included in derivative loss	(836)	(614)
Non-qualified derivative contracts included in derivative gain (loss)	367	(515)
Interest rate derivative contract settlements included in interest expense	(275)	28
Total gain	$ 4,361	$ 459

Oil and Gas Commodity Hedges

To mitigate a portion of the potential exposure to adverse market changes, the Company has entered into various derivative contracts. The Company has in place derivative contracts, which include swap and collar arrangements, for the sale of oil and natural gas. Please refer to the tables under *Summary of Oil and Gas Production Hedges in Place* in Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations for details regarding the Company's hedged volumes and associated prices. As of March 31, 2006, the Company has hedge contracts in place through 2011 for a total of approximately 12 million Bbls and 68 million MMBtu of anticipated production. The Company anticipates that all forecasted transactions will occur by the end of their originally specified periods. All contracts are entered into for other than trading purposes.

The Company attempts to qualify its oil and natural gas derivative instruments as cash flow hedges for accounting purposes. As of March 31, 2006, all oil and natural gas derivative instruments qualified as cash flow hedges for accounting purposes. The estimated fair value of oil and natural gas derivative contracts designated and qualifying as cash flow hedges under SFAS No. 133 was a net liability of $75.0 million at March 31, 2006.

Gains or losses from the settlement of oil and gas derivative contracts are reported in the total operating revenues section on the consolidated statements of operations. Changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash

flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in derivative loss in the consolidated statement of operations.

The Company seeks to minimize ineffectiveness by entering into oil derivative contracts indexed to NYMEX and gas contracts indexed to regional index prices associated with pipelines in proximity to the Company's areas of production. As the Company's derivative contracts contain the same index as the Company's sale contracts, this results in hedges that are highly correlated with the underlying hedged item.

Derivative loss for the three months ended March 31, 2006, and 2005, includes a net loss of $836,000 and a net loss of $614,000, respectively, from ineffectiveness related to oil and natural gas derivative contracts.

As of March 31, 2006, the amount of unrealized loss net of deferred income taxes to be reclassified from accumulated other comprehensive income to oil and gas production operating revenues in the next twelve months was $870,000.

Interest Rate Derivative Contracts

The Company has various interest rate derivative contracts. There are offsetting trades that have fixed the future payments under these derivative contracts. The fair value of the interest rate derivatives was a liability of $514,000 as of March 31, 2006. The Company recorded a net derivative gain in the consolidated statements of operations of $132,000 for the three-month period ended March 31, 2006, and a net loss of $676,000 for the three-month period ended March 31, 2005, from mark-to-market adjustments for these derivatives. These swaps do not qualify for fair value hedge treatment under SFAS No. 133 and related pronouncements.

Convertible Note Derivative Instrument

The contingent interest provision of the Convertible Notes is considered an embedded equity-related derivative that is not clearly and closely related to the fair value of an equity interest and therefore must be separately accounted for as a derivative instrument. The value of the derivative at issuance of the Convertible Notes in March 2002 was $474,000. This amount was recorded as a decrease to the Convertible Notes payable in the consolidated balance sheets. Interest expense for each of the three-month periods ended March 31, 2006, and 2005, includes $24,000 of amortization of this derivative. Derivative gain in the consolidated statements of operations for the three-month periods ended March 31, 2006, and 2005, includes net gains of $235,000 and $160,000, respectively, from mark-to-market adjustments for this derivative. The fair value of this derivative was a liability of $233,000 at March 31, 2006.

Note 9 — Pension Benefits

The Company's employees participate in a non-contributory pension plan covering substantially all employees who meet age and service requirements (the "Qualified Pension Plan"). The Company also has a supplemental non-contributory pension plan covering certain management employees (the "Nonqualified Pension Plan").

Components of Net Periodic Benefit Cost

The following table presents the components of the net periodic cost for both the Qualified Pension Plan and the Nonqualified Pension Plan:

	For the Three Months Ended March 31, 2006	2005
	(In thousands)	
Service cost	$ 421	$ 346
Interest cost	163	134
Expected return on plan assets	(83)	(94)
Amortization of net actuarial loss	74	60

Net periodic benefit cost	$ 575	$ 446

Prior service costs are amortized on a straight-line basis over the average remaining service period of active participants. Gains and losses in excess of ten percent of the greater of the benefit obligation and the market-related value of assets are amortized over the average remaining service period of active participants.

Contributions

St. Mary previously disclosed in its financial statements for the year ended December 31, 2005, that it expected to contribute approximately $1.3 million to the pension plans in 2006. Presently, the Company still believes it will contribute this amount during 2006.

Note 10 - Asset Retirement Obligations

The Company recognizes an estimated liability for future costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and a corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is completed or acquired. The increase in carrying value is included in proved oil and gas properties in the consolidated balance sheets. The Company depletes the amount added to proved oil and gas property costs and recognizes accretion expense in connection with the discounted liability over the remaining estimated economic lives of the respective oil and gas properties. Cash paid to settle asset retirement obligations is included in the operating section of the Company's consolidated statement of cash flows.

The Company's estimated asset retirement obligation liability is based on historical experience in abandoning wells, estimated economic lives, estimates as to the cost to abandon the wells in the future, and federal and state regulatory requirements. The liability is discounted using a credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. The credit-adjusted risk-free rates used to discount the Company's abandonment liabilities range from 6.50 percent to 7.25 percent. Revisions to the liability could occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding the abandonment of wells.

A reconciliation of the Company's asset retirement obligation liability is as follows:

	For the Three Months Ended March 31, 2006	2005
	(In thousands)	
Beginning asset retirement obligation	$ 66,078	$ 40,911
Liabilities incurred	555	2,169
Liabilities settled	(589)	(323)
Accretion expense	1,152	705
Ending asset retirement obligation	$ 67,196	$ 43,462

Note 11 – Repurchase of Common Stock

Stock Repurchase Program

In August 2004 the Company's Board of Directors approved an increase in the number of shares that may be repurchased under the original authorization approved in August 1998 to 6,000,000, effective as of the date of the resolution. The shares may be repurchased from time to time in open market transactions or privately negotiated transactions subject to market conditions and other factors including certain provisions of St. Mary's existing credit facility agreement and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flow, and borrowings under the credit facility.

St Mary has not repurchased any shares of common stock under the program during 2006. As of March 31, 2006, the Company had the authority to repurchase 3,846,118 shares under the stock repurchase program.

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

This discussion contains forward-looking statements. Please refer to the Cautionary Statement about Forward-Looking Statements at the end of this item for an explanation of these types of statements.

Overview of the Company

General Overview

We are an independent energy company focused on the exploration, exploitation, development, acquisition, and production of natural gas and crude oil in the United States. We earn greater than 95 percent of our revenues and generate our cash flows from operations primarily from the sale of produced natural gas and crude oil. Our oil and gas reserves and operations are concentrated primarily in various Rocky Mountain basins, including the Williston, Big Horn, Wind River, Powder River, and Greater Green River Basins; the Mid-Continent Anadarko and Arkoma Basins; the Permian Basin; the tight sandstone reservoirs of East Texas and North Louisiana; and onshore Gulf Coast and offshore Gulf of Mexico. We have developed a balanced portfolio of proved reserves, development drilling opportunities, and non-conventional gas prospects.

Oil and Gas Prices

Our results of operations and financial condition are significantly affected by oil and natural gas commodity prices, which can fluctuate dramatically. The first quarter was characterized by lower natural gas prices, as compared to the end of 2005, and relatively steady oil prices. Our realized natural gas and oil prices, including the impact of hedges, were $8.28 per Mcf and $54.47 per Bbl, respectively, in the first quarter 2006. These prices compare to average NYMEX of $9.08 per MMBtu and $63.48 per Bbl, respectively, in the first quarter of 2006. Excluding the effect of hedging our realized natural gas and oil price was $7.58 per Mcf and $56.98 per Bbl, respectively. Our natural gas price realization was improved by $8.9 million of hedging gains while our oil price realization was decreased by $3.8 million of hedging losses.

The first quarter of 2006 brought relatively large increases to basis differentials for natural gas, in all of our major gas producing regions, as well as for crude oil produced in the Rockies. First quarter natural gas basis differentials at our major trading locations were as high as $2.73 per MMBtu. We expect to see a moderating of the natural gas differentials in the second quarter. The oil differential in the Rockies has continued to expand to levels ranging as high as $10 to $14 per Bbl in the Williston Basin and $20 to $30 per Bbl in Wyoming for some of our sour crude. The increases in the crude differentials from previous periods are believed to be due to an overall increase in the productive capacity for these regions, a greater concentration of synthetic crude from Canadian sources, downtime at area refineries over the winter, and lack of pipeline capacity to transport oil to market. We have begun to see improvement in the crude oil differentials in the month of May due to refineries that are now operating at or near full capacity, increase in highway construction, which impacts our Wyoming asphalt sour production, and improvements in temperatures which leads to increased demand. However, since this relief will not start until May, we are expecting to see our net oil realization basis difference for us to be $6.50 to $7.50 per Bbl in the second quarter.

In April 2006 we saw a record high NYMEX crude oil price resulting from increased tensions in the Middle East and Nigeria as well as continued global demand increases. We have also seen natural gas prices increase in April 2006 relative to the average price for the first quarter 2006, which seems to be caused by warmer than seasonal weather in the southwest and concerns about the upcoming hurricane season.

Cost Environment

We continue to see cost escalation in the service sector affect our business. Rig rates, field service costs, workover costs, material prices, or any cost associated with drilling, completing, and operating wells are factors in cost escalation. Historically, cost changes have lagged the commodity prices, both on upward and downward price trends. We believe that there is a highly dynamic relationship between service costs and commodity prices and that it is not possible to predict where the break-over point of one relative to the other will occur. In making our investment decisions, we evaluate current economics on an individual investment basis prior to proceeding with an investment. Although we have a formal process for establishing a drilling budget, our prospect inventory and strong balance sheet give us the flexibility to adjust this budget as additional opportunities arise or as the economics of our planned activities change.

As of the current time, our drilling budget for 2006 has been reduced to $477 million and we have budgeted $100 million for acquisitions. While our budget is unchanged from a cost perspective, we are reducing our 2006 drilling budget to reflect the impact of permitting delays at our Hanging Woman Basin project.

Hedging Activities

We have an active hedging program in which we hedge the first two to three years of an acquisition's risked production, as well as a portion of our existing forecasted production on a discretionary basis. In the fourth quarter of 2005, we hedged a significant portion of anticipated future production from our currently producing properties using zero-cost collars. These contracts supplement our previous swap and collar contracts. We also hedged a portion of specific forecasted natural gas production for 2006 and 2007 using swap contracts. Taking into account all oil and gas production hedge contracts in place through April 24, 2006, we have hedged approximately 12 million Bbls and 68 million MMBtu of our anticipated production through the year 2011. Overall we have hedged an estimated 57 percent of our 2006 forecast oil production volumes and 31 percent of our 2006 forecast natural gas production volumes using both zero-cost collars and swap contracts. Using current differentials, we estimate that the break even NYMEX price for these commodities derivatives is approximately $54.22 per Bbl and $9.19 per MMBtu over the remainder of 2006. Because of the basis expansion in the Rockies, we recorded approximately $836,000 of ineffectiveness related to our derivative contracts in the first quarter of 2006. Please see Note 8 — Derivative Financial Instruments in Part I, Item 1 of this report for additional information regarding our oil and gas hedges, and see the caption, *Summary of Oil and Gas Production Hedges in Place,* later in this section.

Net Profits Plan

With the increase in future oil prices more than offsetting the relative decrease in near term natural gas prices; the estimated liability associated with our Net Profits Plan recorded in the March 2006 financial statements has increased by $7.0 million. We have also expensed $6.9 million of compensation costs associated with the cash payments for the Net Profits Plan for the first quarter of 2006. This amount is slightly lower than originally budgeted due to increased capital spending in existing payout pools, the timing of payout for newer pools, and the relative decrease in natural gas prices since the time the 2006 budget was developed. The rate of increase for the liability associated with the Net Profits Plan should be fairly stable throughout the year based on current price projections. We have adjusted our forecast to approximately $35 million of cash payments to be made for 2006. The actual cash payments made are dependent on actual production, realized prices, and operating and capital costs associated with the individual pools. Actual cash payments will be inherently different from the estimated liability amount. Additional discussion is included in the analysis in the *Comparison of Financial Results and Trends* sections below.

The calculation of the estimated liability associated with the Net Profits Plan requires management to prepare its best estimate of future amounts payable from the Net Profits Plan. On a monthly basis, we calculate estimates of the payments to be made for each individual pool under the Net Profits Plan. The underlying basis for our calculations are forecasted oil and gas production from the properties that comprise each individual pool, price assumptions, and discount rate. In most cases, the cash flow streams used in these calculations will span more than 20 years. We generally use a 15 percent discount rate to calculate the present value of these future payments, and the resulting amount is recorded as a liability. Commodity prices impact the calculated cash flows during periods after payout and can dramatically affect the timing of the estimated date of payout of the individual pools. Our commodity price assumptions are currently determined from a rolling average of actual prices realized together with adjusted NYMEX strip prices for the next 12 months for a total of 36 months of data. This average is supplemented by including the effect of hedge prices for the percentage of forecasted production hedged in the relevant period. The calculation of the estimated liability for the Net Profits Plan is highly sensitive to our price estimates and discount rate assumptions. For example, if we changed the prices in our calculation by ten percent, the liability recorded at March 31, 2006, would differ by approximately $31 million. A one percent change in the discount rate would result in a change of approximately $6 million. We frequently evaluate the assumptions used in our calculations to evaluate the possible impacts stemming from the current market environment. This review considers current oil and gas prices, discount rates, and overall market conditions.

Stock-Based Compensation

On January 1, 2006, we adopted SFAS No. 123R, Share Based Payments, which requires the measurement of compensation expense for all stock-based awards made to employees and directors including stock options, employee stock purchases under the Employee Stock Purchase Plan, and restricted stock units granted under the Restricted Stock Plan. We adopted SFAS No. 123R using the modified prospective transition method. Our consolidated financial statements as of and for the three months ended March 31, 2006, reflect the impact of SFAS No. 123R. Total stock-based compensation expense for the three months ended March 31, 2006, was approximately $3.2 million, which included $500,000 of expenses related to stock options and employee stock purchases under the ESPP recognized under SFAS No. 123R. We have expensed all SFAS No. 123R costs upon adoption associated with those individuals that do not have a future service requirement due to their existing term of service to the Company, their age, and service with us.

Prior to the adoption of SFAS No. 123R, we accounted for stock-based compensation expense using the intrinsic value and recognition and measurement principles detailed in APB Opinion No. 25. Upon adoption of SFAS No. 123R, we selected the Black-Scholes option pricing model to determine the estimated fair value for stock-based awards.

First Quarter 2006 Highlights

Our net income for the quarter ended March 31, 2006, was $50.5 million or $0.76 per diluted share compared to 2005 results of $35.1 million or $0.54 per diluted share. Production for the quarter was 22.0 BCFE. This represents a six percent increase from the same period a year ago and is basically flat from the previous quarter. Per

MCFE lease operating expense and transportation expense increased $0.26 to $1.33 per MCFE driven by a high amount of workover expense in the Rockies as well as single well events in the Mid-Continent and Gulf Coast. Production taxes increased $0.06 to $0.55 per MCFE and DD&A, including ARO accretion expense, increased $0.11 to $1.57 per MCFE. We discuss these financial results and trends in more detail below.

In the first quarter of 2006, net income was affected by lower natural gas prices, compared to recent historical prices, and steady oil prices. Our realized natural gas and oil prices, including the impact of hedges, were $8.28 per Mcf and $54.47 per Bbl, respectively. These prices compare to

average NYMEX prices of $9.08 per MMBtu of natural gas and $63.48 per Bbl of oil in the first quarter of 2006. The average NYMEX prices represented a decrease of 29 percent for gas and an increase of six percent for oil compared to the fourth quarter of 2005 and were 44 percent higher for gas and 27 percent higher for oil compared to the quarter ending March 31, 2005.

The table below provides information regarding selected production and financial information for the quarter ended March 31, 2006, and the immediately preceding three quarters. Additional detail of per MCFE cost is contained later in this section.

	For the Three Months Ended			
	March 31, 2006	December 31, 2005	September 30, 2005	June 30, 2005
	(In millions)			
Production (MCFE)	22.0	21.9	23.1	21.8
Oil and gas production revenues before the effects of hedging	$ 184.1	$ 231.6	$ 203.1	$ 160.4
Lease operating expense	$ 26.3	$ 23.8	$ 22.9	$ 19.2
Transportation costs	$ 2.9	$ 2.6	$ 1.8	$ 1.8
Production taxes	$ 12.0	$ 16.1	$ 13.4	$ 9.2
General and administrative expense	$ 10.8	$ 9.5	$ 9.8	$ 7.5
Net income	$ 50.5	$ 51.2	$ 27.3	$ 38.3
Percentage change from previous quarter:				
Production (MCFE)	—%	(5)%	6%	
Oil and gas production revenues	(21)%	14%	27%	
Lease operating expense	11%	4%	19%	
Transportation costs	12%	44%	—%	
Production taxes	(25)%	20%	46%	
General and administrative expense	14%	(3)%	31%	
Net income	(1)%	88%	(29)%	

Outlook for the Remainder of 2006

While oil and gas prices remain very volatile, we have an inventory of drilling prospects that is attractive at various price environments. We believe we will continue to have access to drilling rigs as rig counts continue to grow. However, the ability of drilling rig companies to hire qualified crews could impact our ability to drill wells. Additionally, we continue to feel the impact of escalating rig and other service costs.

The decreased emphasis on the acquisition component of our budget reflects the overall competitiveness of the acquisition market and the high prices being paid in recent acquisition transactions in our industry. More importantly, it reflects the strides we have made to advance our prospect inventory and activity level on the drilling side. We continue to maintain a disciplined approach to acquisitions as we actively evaluate acquisition opportunities. Over the remainder of 2006 we will continue to execute our business plan, including the following:

- *Rockies Conventional* - In the first three months of 2006 we have completed two wells in the Bakken formation with three wells drilling and seven wells in the process of completing at quarter end. We expect to participate in the drilling of 30 wells in the Bakken formation during 2006.

- *Rockies – Hanging Woman Basin Coalbed Natural Gas* - In the first three months of 2006 we have completed 11 wells and drilled 47 wells in our Hanging Woman Basin coalbed natural gas project. We plan to drill over 140 wells during the year in total. Production for the project continues to be ahead of forecasted volumes and was approximately 4,800 MCFD gross, 3,300 MCFD net, from 170 producing wells as of May 2, 2006.

  The reduction in the number of wells planned for this year is the result of environmental and regulatory permitting issues that are impacting the timing of drilling approximately 60 wells located in Montana as well as selected wells located in Wyoming. The potential Montana delays are a result of the necessary regulatory approval of our water development plan on state and fee acreage. Delays in Wyoming permitting and drilling are anticipated in certain areas due to wildlife stipulations. We expect this deferral to move these developments into early 2007.

- *Mid-Continent* - As of the end of the first three months of 2006 we have completed our fifth horizontal Cromwell sandstone well, our second horizontal Woodford shale well, and we are evaluating our first Wapanucka limestone well. We plan to participate in the drilling of approximately 20 horizontal wells in the Centrahoma area during 2006.

  In Northeast Mayfield we participated in the completion of five wells with a 100 percent success rate. Four wells are completing and three wells are drilling as of the end of the first quarter.

- *ArkLaTex* – As of the end of the first three months of 2006, we have completed ten wells located in this region and have six wells drilling and 15 wells completing. In Elm Grove, all six wells attempted during the quarter were successfully completed. At March 31, 2006, three wells were drilling and five wells were completing in the field. Our plan contemplates the participation in the drilling of 48 wells at Elm Grove this year.

- *Gulf Coast and Permian* - In the first three months of 2006 we have completed one well and recompleted another well in the Judge Digby that together are currently producing 95 MMCFD gross, 11 MMCFD net to our interest.

- We anticipate that production for 2006 will be between 96 BCFE and 98 BCFE, which exceeds 2005 reported production of 87.4 BCFE by approximately 11 percent. This increase is a result of anticipated success in our drilling programs.

A quarter-to-quarter overview of selected production and financial information, including trends:

Selected Operations Data (In thousands, except sales price and per MCFE amounts)

	For the Three Months Ended March 31, 2006	For the Three Months Ended March 31, 2005	% Change Between Periods
Net production volumes			
Natural gas (Mcf)	12,789	12,047	6%
Oil (Bbl)	1,529	1,433	7%
MCFE (6:1)	21,962	20,647	6%
Average daily production			
Natural gas (Mcf per day)	142	134	6%
Oil (Bbl per day)	17	16	7%
MCFE per day (6:1)	244	229	6%
Oil & gas production revenues(1)			
Gas production revenue	$ 105,891	$ 74,891	41%
Oil production revenue	83,279	65,039	28%
Total	$ 189,170	$ 139,930	35%
Oil & gas production expense			
Lease operating expenses	$ 26,332	$ 20,236	30%
Transportation costs	2,847	1,880	51%
Production taxes	12,035	10,043	20%
Total	$ 41,214	$ 32,159	28%
Average realized sales price(1)			
Natural gas (per Mcf)	$ 8.28	$ 6.22	33%
Oil (per Bbl)	$ 54.47	$ 45.37	20%
Per MCFE Data:			
Average net realized price(1)	$ 8.61	$ 6.78	27%
Lease operating expense	(1.20)	(0.98)	22%
Transportation costs	(0.13)	(0.09)	44%
Production taxes	(0.55)	(0.49)	12%
General and administrative	(0.49)	(0.29)	69%
Operating profit	$ 6.24	$ 4.93	27%
Depletion, depreciation, amortization, and abandonment liability accretion	$ 1.57	$ 1.46	8%

(1) Includes the effects of our hedging activities

Financial Information (In thousands, except per share amounts):

	March 31, 2006	December 31, 2005	% Change Between Periods
Working capital	$ 43,140	$ 4,937	774%
Long-term debt	$ 99,909	$ 99,885	—%
Stockholders' equity	$ 634,155	$ 569,320	11%

	For the Three Months Ended March 31, 2006	For the Three Months Ended March 31, 2005	% Change Between Periods
Basic net income per common share	$ 0.88	$ 0.61	44%
Diluted net income per common share	$ 0.76	$ 0.54	41%
Basic weighted-average shares outstanding	57,233	57,231	—%
Diluted weighted-average shares outstanding	67,334	67,047	—%

The preceding table is presented as a summary of information relating to those key indicators of financial condition and operating performance that we believe to be most important. We present per MCFE information since we use this information to evaluate our performance relative to our peers and to measure trends that we believe require analysis. Our period-to-period comparison of financial results presented later provides additional details for the per MCFE differences between reported periods.

We expect oil and gas production expenses to generally correspond with oil and gas prices. Accordingly, as realized prices change, production taxes will change directionally. Lease operating expense will be impacted by competition for scarce resources in the oil and gas service sector. We continue to see annual service cost increases in the ten to twenty percent range. Depreciation, depletion, and amortization will increase due to the higher costs associated with finding and acquiring crude oil and natural gas. We expect general and administrative expense will continue to increase through 2006 primarily as a result of our incentive compensation plans and increased charitable contributions, which we base on a percentage of our net income. The remaining information in the table relates to information we have provided in operations update press releases and is intended to supplement the discussion above.

Overview of Liquidity and Capital Resources

We believe that we have sufficient liquidity and capital resources to execute our business plans for the foreseeable future.

Sources of Cash

Our primary sources of liquidity are the cash provided by operating activities and debt financing. We believe that we can access capital markets if needed, although we have no current plans to do so. Our large percentage increase in working capital is a result of cash builds as we benefit from commodity prices.

Our current credit facility

We have a five-year, $500 million credit facility agreement with Wachovia Bank, Wells Fargo Bank and eight other participating banks. This credit facility has a borrowing base currently set at $500 million, and we have elected a commitment amount of $200 million. We believe this commitment level is adequate for our near-term liquidity requirements. The credit agreement has a maturity date of April 7, 2010. We must comply with certain financial and non-financial covenants, and we are currently in compliance with all of those covenants. Interest and commitment fees are accrued based on the borrowing base utilization percentage. Euro-dollar loans accrue interest at LIBOR plus the applicable margin from the utilization table, and Alternate Base Rate loans accrue interest at prime plus the applicable margin from the utilization table. This table is located in Note 7 of Part I, Item 1 of this report. Borrowings under the new facility are secured by the majority of our oil and gas properties and a pledge of the common stock of our material subsidiary companies.

Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the consolidated statements of operations. We had no outstanding loan balances as of March 31, 2006 or April 24, 2006. As of March 31, 2006, we had a cash and short-term investment balance of $62.5 million.

Our weighted-average interest rate paid in the first three months of 2006 was 8.2 percent and included fees paid on the unused portion of the credit facility aggregate commitment amount, amortization of deferred financing costs, amortization of the contingent interest embedded derivative associated with the convertible notes, and the effects of interest rate swaps.

Uses of Cash

We use cash for the acquisition, exploration, and development of oil and gas properties and for the payment of debt obligations, trade payables, income taxes, common stock repurchases and stockholder dividends. In the first three months of 2006 we incurred costs of $101.3 million on capital development using cash flows from operations. We also made cash payments for income taxes of $9.8 million. We estimate that approximately 50 to 55 percent of our total income tax liability for 2006 will result in cash taxes that are payable on a current basis.

As of March 31, 2006, we have Board authorization to repurchase up to 3.8 million shares of our common stock under our stock repurchase program. These shares may be repurchased from time to time in open market transactions or privately negotiated transactions subject to market conditions and other factors including certain provisions of our existing bank credit facility agreement and compliance with securities laws.

Our Board declared a semi-annual dividend of $0.05 per share payable on May 15, 2006, to shareholders of record as of the close of business May 5, 2006. We have sufficient liquidity to make this payment. Our intention is to continue to make these dividend payments for the foreseeable future subject to our future earnings, our financial condition, possible credit facility covenants, and other currently unexpected factors which could arise.

The following table presents amounts and percentage changes in cash flows between the three-month periods ending March 31, 2006 and March 31, 2005. The analysis following the table should be read in conjunction with our consolidated statements of cash flows in Part I, Item 1 of this report.

	For the Three Months Ended March 31, 2006	For the Three Months Ended March 31, 2005	Change	Percent Change
	(In thousands)			
Net cash provided by operating activities	$ 129,242	$ 92,131	$ 37,111	40%
Net cash used in investing activities	$ (87,552)	$ (94,278)	$ (6,726)	(7)%
Net cash provided by financing activities	$ 4,447	$ 13,249	$ (8,802)	(66)%

Analysis of cash flow changes between the three months ended March 31, 2006, and March 31, 2005

Operating activities. Cash received from oil and gas sales, net of the effects of hedging, increased $81.7 million to $220.4 million for the three-month period ended March 31, 2006, from $138.7 million for the three-month period ended March 31, 2005. This increase was the result of a six percent increase in production and a 27 percent increase in our net realized prices between the two periods. Changes in current assets and liabilities combined with cash expenditures for oil and gas production expenses, exploration expenses, and administrative expenses increased by $28.8 million between the two comparable periods, and net cash payments made for income taxes increased $3.8 million. The future operating cash flow impact of the increased percentage of hedged production using zero-cost collars will have the effect of reducing the sensitivity to movements in oil and gas prices to the extent prices fall outside of the collar range.

Investing activities. Total cash outflow for 2006 capital expenditures, as adjusted for accruals, has increased $24.0 million, or 38 percent, and cash outflow related to the acquisition of oil and gas properties has decreased $34.5 million, or 99 percent, compared to the same period in 2005.

Financing activities. We received $1.2 million less for the sale of our common stock for the exercise of stock options and $10.0 million less in proceeds from our credit facility in the first quarter of 2006 compared to the same period in 2005. This amount was off-set by the $2.4 million increase in income tax benefit from the exercise of stock options.

Capital Expenditure Forecast

We use our capital resources primarily for the exploration and development of oil and gas properties and for acquisitions. Our capital expenditures forecast for drilling is $477 million this year, excluding non-cash asset retirement obligation capitalized assets. Anticipated ongoing 2006 exploration and development expenditures and budgeted gross wells for each of our core areas are presented in the following table. The timing of drilling and completion of wells is variable and will differ from these estimates.

	Exploration and Development Expenditures	
	(In millions)	
Mid-Continent region	$	172
Rocky Mountain region		141
ArkLaTex region		66
Gulf Coast region		67
Coalbed natural gas		27
Permian Basin region		4
	$	477

We regularly review our capital expenditure budget to reflect changes in current and projected cash flows, acquisition opportunities, drilling opportunities, debt requirements, regional cost inflation, and other factors. The above allocations are subject to change based on these factors.

The following table sets forth certain information regarding the costs incurred by us in our oil and gas property acquisition, exploration, and development activities, whether capitalized or expensed.

	For the Three Months Ended March 31,			
	2006		2005	
	(In thousands)			
Development costs	$	66,683	$	53,246
Exploration costs		28,509		12,107
Acquisitions:				
Proved		125		39,324
Unproved		—		2,246
Leasing activity		5,977		4,446
Total, including asset retirement obligation	$	101,294	$	111,369

The costs we incurred for capital and exploration activities in 2006 decreased $10.1 million or nine percent compared to the same quarter in 2005. Excluding acquisitions of $39.9 million in the 2005 period, our spending is up $29.8 million from the comparable quarter in the prior year.

We believe that internally generated cash flows, together with our credit facility, will be sufficient to fund our planned operational, drilling, and acquisition expenditures for the foreseeable future. The amount and allocation of future capital and exploration expenditures will depend upon a number of factors including the number and size of available economic acquisition and drilling opportunities, our cash flows from operating and financing activities, and our ability to assimilate acquisitions we make. Also, the impact of oil and gas prices on investment opportunities, the availability

of capital and borrowing facilities, and the success of our development and exploratory activities could lead to changes in funding requirements for future development.

Financing alternatives

The debt and equity financing capital markets remain attractive to energy companies that operate in the exploration and production segment. This is a result of strong commodity prices and the general strength reflected in the balance sheets of the companies in this segment. As our cash balance and availability under our existing credit facility are significant, we are not currently considering accessing the capital markets in 2006. If additional development or acquisition opportunities arise that exceed our currently available resources, we may consider other forms of financing, including the public offering or private placement of equity or debt securities.

Commodity Price Risk and Interest Rate Risk

We are exposed to market risk, including the effects of changes in oil and gas commodity prices and changes in interest rates as discussed below and under the caption "*Summary of Interest Rate Hedges in Place.*" Since we produce and sell natural gas and crude oil, our financial results are affected when prices for these commodities fluctuate. In order to reduce the impact of fluctuations in commodity prices, we enter into hedging transactions. Changes in interest rates can affect the amount of interest we earn on our cash, cash equivalents and short-term investments and the amount of interest we pay on borrowings under our revolving credit facility. Changes in interest rates do not affect the amount of interest we pay on our fixed rate convertible notes, but do affect the fair value of that debt. We anticipate that all hedge and derivative contract transactions will occur as expected.

There has been no material change to the natural gas and crude oil price sensitivity analysis previously disclosed. Please see the corresponding section under Part II, Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2005.

Summary of Oil and Gas Production Hedges in Place

Our oil and natural gas derivative contracts include swap and collar arrangements. All contracts are entered into for other than trading purposes.

Our net realized oil and gas prices are impacted by hedges we have placed on future forecasted production. We have historically entered into hedges of existing production around the time we make acquisitions of producing oil and gas properties. Our intent has been to lock in a significant portion of an equivalent amount of existing production to the prices we used to evaluate the risked economics of our acquisition. We also hedge a portion of our forecasted production on a discretionary basis.

In a typical commodity swap agreement, if the agreed upon published, third-party index price is lower than the swap fixed price, we receive the difference between the index price per unit of production and the agreed upon swap fixed price. If the index price is higher than the swap fixed price, we pay the difference. For collar agreements, we receive the difference between an agreed upon index and the floor price if the index price is below the floor price. We pay the difference between the agreed upon contracted ceiling price and the index price only if the index price is above the contracted ceiling price.

The following tables describe the volumes, average contract prices, and fair value of contracts we have in place as of March 31, 2006. As of March 31, 2006, our hedged positions totaled approximately 12 million Bbls and 68 million MMBtu of anticipated future production through 2011. We seek to minimize basis risk and index the majority of our oil contracts to NYMEX prices and our gas contracts to various regional index prices associated with pipelines in proximity to our areas of gas production.

Oil Contracts

Oil Swaps

Contract Period	Volumes (Bbl)	Weighted-Average Contract Price (Per Bbl)	Fair Value at March 31, 2006 Asset/(Liability) (In thousands)
Second quarter 2006			
NYMEX WTI	327,976	$ 54.53	$ (4,355)
IF Bow River	30,000	$ 40.68	(363)
Third quarter 2006			
NYMEX WTI	281,372	$ 54.79	(4,007)
IF Bow River	33,000	$ 40.46	(403)
Fourth quarter 2006			
NYMEX WTI	155,686	$ 50.57	(2,871)
IF Bow River	30,000	$ 37.54	(267)
2007			
NYMEX WTI	314,786	$ 39.78	(8,769)
IF Bow River	76,000	$ 38.85	(826)
2008			
NYMEX WTI	35,000	$ 56.63	(379)
All oil swap contracts			$ (22,240)

Oil Collars

Contract Period	NYMEX WTI Volumes (Bbl)	Weighted-Average Floor Price (Per Bbl)	Weighted-Average Ceiling Price (Per Bbl)	Fair Value at March 31, 2006 Asset/(Liability) (In thousands)
Second quarter 2006	669,000	$ 52.09	$ 72.63	$ (687)
Third quarter 2006	648,000	$ 52.10	$ 72.66	(1,867)
Fourth quarter 2006	739,000	$ 52.23	$ 72.76	(2,696)
2007	2,897,000	$ 51.59	$ 72.78	(12,374)
2008	1,668,000	$ 50.00	$ 69.82	(10,387)
2009	1,526,000	$ 50.00	$ 67.31	(10,206)
2010	1,367,500	$ 50.00	$ 64.91	(9,320)
2011	1,236,000	$ 50.00	$ 63.70	(7,979)
All oil collars				$ (55,516)

Gas Contracts

Gas Swaps

Contract Period	Volumes (MMBtu)	Weighted-Average Contract Price (Per MMBtu)	Fair Value at March 31, 2006 Asset/(Liability) (In thousands)
Second quarter 2006			
IF ANR OK	1,960,000	$ 8.08	$ 3,884
IF PEPL	330,000	$ 5.31	(245)
IF CIG	330,000	$ 6.30	202
IF NGPL	610,000	$ 9.77	2,253
IF CenterPoint	380,000	$ 5.67	(361)
Third quarter 2006			
IF ANR OK	1,740,000	$ 8.51	3,127
IF PEPL	330,000	$ 5.29	(440)
IF CIG	300,000	$ 6.35	69
IF NGPL	580,000	$ 9.94	1,881
IF CenterPoint	360,000	$ 5.67	(583)
Fourth quarter 2006			
IF ANR OK	1,020,000	$ 9.06	1,873
IF PEPL	110,000	$ 5.31	(159)

IF CIG	300,000	$	6.70	(116)
IF NGPL	550,000	$	10.24	1,294
IF CenterPoint	160,000	$	5.71	(345)
2007				
IF ANR OK	1,640,000	$	9.22	1,125
IF NGPL	3,280,000	$	9.16	2,590
IF CIG	630,000	$	6.42	(736)
All gas swap contracts				$ 15,313

Gas Collars

Contract Period	Volumes (MMBtu)		Weighted-Average Floor Price (Per MMBtu)		Weighted-Average Ceiling Price (Per MMBtu)		Fair Value at March 31, 2006 Asset/(Liability) (In thousands)
Second quarter 2006							
IF ANR OK	350,000	$	6.89	$	9.13	$	308
IF PEPL	760,000	$	7.27	$	13.55		980
IF CIG	70,000	$	7.00	$	11.52		93
IF HSC	480,000	$	7.71	$	13.80		427
NYMEX Henry Hub	400,000	$	8.00	$	14.50		346
Third quarter 2006							
IF ANR OK	450,000	$	6.92	$	9.28		305
IF PEPL	720,000	$	7.27	$	13.54		783
IF CIG	210,000	$	7.00	$	11.52		255
IF HSC	430,000	$	7.71	$	13.80		393
NYMEX Henry Hub	330,000	$	8.00	$	14.50		305
Fourth quarter 2006							
IF ANR OK	100,000	$	7.00	$	9.82		71
IF PEPL	655,000	$	7.90	$	14.07		719
IF CIG	390,000	$	7.23	$	12.51		365
IF HSC	400,000	$	8.10	$	14.20		407
NYMEX Henry Hub	270,000	$	8.63	$	15.54		224
2007							
IF PEPL	7,960,000	$	7.35	$	10.74		(411)
IF CIG	3,120,000	$	6.66	$	9.36		(380)
IF HSC	1,240,000	$	7.84	$	10.60		(291)
NYMEX Henry Hub	790,000	$	8.28	$	11.32		(284)

Gas Collars (Continued)

Contract Period	Volumes (MMBtu)		Weighted-Average Floor Price (Per MMBtu)		Weighted-Average Ceiling Price (Per MMBtu)	Fair Value at March 31, 2006 Asset/(Liability) (In thousands)
2008						
IF PEPL	6,600,000	$	6.28	$	9.42	(2,871)
IF CIG	2,880,000	$	5.60	$	8.72	(1,203)
IF HSC	960,000	$	6.57	$	9.70	(512)
NYMEX Henry Hub	480,000	$	7.00	$	10.57	(230)
2009						
IF PEPL	5,510,000	$	5.30	$	9.25	(2,737)
IF CIG	2,400,000	$	4.75	$	8.82	(967)
IF HSC	840,000	$	5.57	$	9.49	(427)
NYMEX Henry Hub	360,000	$	6.00	$	10.35	(167)
2010						
IF PEPL	4,945,000	$	5.31	$	7.61	(2,893)
IF CIG	2,040,000	$	4.85	$	7.08	(975)
IF HSC	600,000	$	5.57	$	7.88	(343)
NYMEX Henry Hub	240,000	$	6.00	$	8.38	(143)
2011						
IF PEPL	4,225,000	$	5.31	$	6.51	(2,662)
IF CIG	1,800,000	$	5.00	$	6.32	(734)
IF HSC	480,000	$	5.57	$	6.77	(283)
NYMEX Henry Hub	120,000	$	6.00	$	7.25	(66)

All gas collars	$	(12,598)

Please see Note 8 – Derivative Financial Instruments in Part I, Item 1 of this report for additional information regarding our oil and gas hedges.

Summary of Interest Rate Hedges in Place

The Company has various interest rate derivative contracts. There are offsetting trades that have fixed the future payments under these contracts. The fair value of the interest rate derivatives was a liability of $514,000 as of March 31, 2006. The Company recorded a net derivative gain in the consolidated statements of operations of $132,000 for the three-month period ended March 31, 2006, and a net loss of $676,000 for the three-month period ended March 31, 2005, from mark-to-market adjustments for these derivatives. These swaps do not qualify for fair value hedge treatment under SFAS No. 133 and related pronouncements.

Market risk is estimated as the potential change in fair value resulting from an immediate hypothetical one-percentage point parallel shift in the yield curve. For fixed-rate debt, interest rate changes affect the fair market value but do not impact results of operations or cash flows. Conversely, interest rate changes for floating-rate debt generally do not affect the fair market value but do impact future results of operations and cash flows, assuming other factors are held constant. The carrying amount of our floating-rate debt typically approximates its fair value, although we had no floating rate debt outstanding as of March 31, 2006. Our fixed rate debt outstanding at this same date was

$100 million associated with the Convertible Notes. Based on the character of our debt outstanding as of the end of the year, we do not believe there is any cash flow impact that could result from a change in interest rates.

Schedule of Contractual Obligations

The following table summarizes our future estimated principal payments and minimum lease payments for the periods specified (in millions):

Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-Term Debt	$ 106.2	$ —	$ —	$ —	$ 106.2
Operating Leases	9.1	2.4	4.2	2.3	0.2
Other Long-Term Liabilities	87.1	4.5	55.0	26.6	1.0
Total	$ 202.4	$ 6.9	$ 59.2	$ 28.9	$ 107.4

This table includes our 2006 estimated pension liability payment of approximately $1.3 million but excludes the remaining unfunded portion of our estimated pension liability of $2.0 million since we cannot determine with accuracy the timing of future payments.

The table does not include estimated payments associated with our Net Profits Plan. We record a liability for the estimated future payments. However, predicting the precise timing and amount of the liability payments is contingent upon realized pricing, costs and production from the underlying oil and gas properties. We have excluded asset retirement obligations because we are not able to precisely predict the timing for these amounts. The Net Profits Plan, pension liabilities, and asset retirement obligations are discussed in Note 7, Note 8, and Note 9, respectively, of Part IV Item 15 of our Form 10-K for the year ended December 31, 2005, and also in Note 5, Note 9, and Note 10, respectively, of Part I, Item 1 of this report.

Three leases for office space will expire in year one and one office space lease will expire in year two. Estimated costs to replace these leases are not included in the table above. For purposes of the table we assume that the holders of our Convertible Notes will not exercise the conversion feature. If the holders do exercise their conversion feature, we will not have to repay the $100 million, and our common shares outstanding will increase by 7,692,307 shares.

Included in the other long-term liabilities line is approximately $75 million of noncurrent accrued derivative liability, which is related to our oil and gas hedges in place through 2011.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet financing other than operating leases, nor do we have any unconsolidated subsidiaries.

Critical Accounting Policies and Estimates

We refer you to the corresponding section in Part II, Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2005, and to the footnote disclosures included in Part I, Item 1 of this report.

Additional Comparative Data in Tabular Form:

	Change Between the Three Months Ended March 31, 2006 and 2005
Oil and gas production revenues	
Increase in oil and gas productionrevenues, net of hedging(In thousands)	$ 49,240
Components of Revenue Increases (Decreases):	
Natural Gas	
Realized price change per Mcf	$ 2.06
Realized price percentage change	33%
Production change (MMcf)	742
Production percentage change	6%
Oil	
Realized price change per Bbl	$ 9.10
Realized price percentage change	20%
Production change (MBbl)	96

Production percentage change	7%

Our Product Mix as a Percentage of Total Oil and Gas Revenue and Production:

	For the Three Months Ended March 31, 2006	2005
Revenue		
Natural gas	56%	54%
Oil	44%	46%
Production		
Natural gas	58%	58%
Oil	42%	42%

Information Regarding the Components of Exploration Expense:

	For the Three Months Ended March 31, 2006	2005
	(In millions)	
Summary of Exploration Expense		
Geological and geophysical expenses	$ 1.5	$ 2.0
Exploratory dry hole expense	0.2	0.2
Overhead and other expenses	9.1	4.9
Total	$ 10.8	$ 7.1

Information Regarding the Effects of Oil and Gas Hedging Activity:

	For the Three Months Ended March 31, 2006	2005
Natural Gas Hedging		
Percentage of gas production hedged	40%	21%
Natural gas MMBtu hedged	5.5 million	2.8 million
Increase in gas revenue	$ 8.9 million	$ 3.8 million
Average realized gas price per Mcf before hedging	$ 7.58	$ 5.90
Average realized gas price per Mcf after hedging	$ 8.28	$ 6.22
Oil Hedging		
Percentage of oil production hedged	65%	18%
Oil volumes hedged (MBbl)	998	252
Decrease in oil revenue	$ (3.8 million)	$ (2.2 million)
Average realized oil price per Bbl before hedging	$ 56.98	$ 46.93
Average realized oil price per Bbl after hedging	$ 54.47	$ 45.37

Comparison of Financial Results and Trends between the Quarters ended March 31, 2006 and 2005

Oil and gas production revenue. Average net daily production increased six percent to a 244.0 MMCFE per day for the quarter ended March 31, 2006, compared with 229.4 MMCFE per day for the quarter ended March 31, 2005. The following table presents specific components that contributed to the increase in revenue between the two quarters:

	Average Net Daily Production Added (MMCFE)	Oil and Gas Revenue Added (In millions)	Production Costs Added (In millions)
Williston Basin Middle Bakken Play	5.0	$ 4.9	$ 0.3
Other wells completed in 2005 and 2006	31.9	23.4	2.9
Wold acquisition	5.2	3.7	2.0
Total	42.1	$ 32.0	$ 5.2

The revenue increases in this table also reflect the difference in oil and gas prices received between the comparable periods. The production increases are offset by natural declines in production from older properties to result in the net increase in production between the quarters presented. Additional production costs reflect increases resulting from inflation and competition for resources.

Oil and gas production expense. Total production costs increased $9.0 million, or 28 percent, to $41.2 million for the first quarter of 2006 from $32.2 million in the comparable period of 2005. Total oil and gas production costs per MCFE increased $0.32 to $1.88 for 2006, compared with $1.56 for 2005. This increase is comprised of the following:

- A $0.04 increase in production taxes in our Mid-Continent region resulting from higher natural gas revenues;
- A $0.02 increase in production taxes due to higher revenue from crude oil in our Rocky Mountain and Permian regions;
- A $0.04 increase in overall transportation cost, of which $0.02 was related to an increase in transportation in the Rocky Mountain region and $0.02 was related to an increase in the ArkLaTex region;

- A $0.17 increase in recurring LOE related to a continued increase in competition for oil and gas service sector resources;

- A $0.05 overall increase in LOE relating to workover charges, due to a significant increase in workover expense in the Rockies, as well as single well workover costs in the Mid-Continent and Gulf Coast regions.

General and administrative. General and administrative expenses increased $4.8 million, or 80 percent, to $10.8 million for the quarter ended March 31, 2006, compared with $6.0 million for the comparable period of 2005. G&A increased $0.20 to $0.49 per MCFE for the first quarter of 2006 compared to $0.29 per MCFE for the same three-month period in 2005 as G&A grew at a faster rate than the six percent increase in production.

A 19 percent increase in employee count has resulted in an increase in base employee compensation of approximately $800,000 between the first quarter of 2006 and the first quarter of 2005. Oil and gas price increases have triggered additional Net Profits Plan payouts and have increased the amounts payable to plan participants. Consequently, the current period realized expense associated with the Net Profits Plan has increased by $4.2 million in 2006 compared with the same quarter in 2005. The increase in Net Profits Plan payments is the result of the significantly higher oil and gas prices, which has the effect of increasing the absolute amount of payments as well as accelerating the time it takes for pools to reach

payout. As of the end of the first quarter 16 of the Company's 19 pools are currently in payout status. No additional pools are expected to reach payout as of the end of 2006.

Cash and RSU bonus expense is $2.2 million higher than in the prior year, which is primarily caused by the increase in amortization of expense associated with stock-based compensation expense. We are recording expense for four periods of RSU grants compared with only three issuances at this same time last year. In 2006 we have the inclusion of the grant made in 2006 for 2005 performance and the additional accrual of the expense estimated for the 2006 plan year. As a result of the implementation of SFAS No. 123(R) we recorded $500,000 of compensation expense related to stock options and the ESPP.

The incentive compensation plan increases combined with a net $1.2 million increase in other compensation expense, including payroll tax and 401(k) contribution expense, were offset by a $4.1 million increase in the amount of G&A that was allocated to exploration expense due to the allocation of the aforementioned incentive plan increases as well as increases in the size of our technical exploration staff.

Change in Net Profits Plan Liability. For the quarter ended March 31, 2006, this non-cash expense increased $2.8 million to $7.0 million from $4.2 million for 2005. This increase reflects our estimation of the effect of a sustained higher price environment and the impact of hedge contracts. This liability is a significant management estimate. Adjustments to the liability are subject to estimation and may change dramatically from period to period based on assumptions used for production rates, reserve quantities, commodity pricing, discount rates, tax rates, and production costs.

Income taxes. Income tax expense totaled $29.6 million for the first quarter of 2006 and $20.7 million for the first quarter of 2005 resulting in effective tax rates of 36.9 percent and 37.1 percent, respectively. The effective rate change from 2005 reflects changes in the mix of the highest marginal state tax rates as a result of acquisition and drilling activity and also reflects other permanent differences including differing estimated effects between years of the domestic production activities deduction.

Accounting Matters

We refer you to Note 2 and Note 5 of Part I, Item 1 of this report for information regarding accounting matters.

Environmental

St. Mary's compliance with applicable environmental regulations has not resulted in any significant capital expenditures or materially adverse effects on our liquidity or results of operations. We believe that we are in substantial compliance with environmental regulations, and we do not currently expect that any material expenditure will be required in the foreseeable future. However, we are unable to predict the impact that future compliance with regulations may have on future capital expenditures, liquidity, and results of operations.

Cautionary Statement About Forward - Looking Statements

This Quarterly Report on Form 10-Q includes certain statements that may be deemed to be "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this Form 10-Q that address activities, events, or developments that St. Mary's management expects, believes, or anticipates will or may occur in the future are forward-looking statements. The words "will," "believe," "anticipate," "intend," "estimate," "expect," "project," and similar expressions are intended to identify forward - looking statements, although not all forward - looking statements contain such identifying words. Examples of forward-looking statements may include discussion of such matters as:

- *the amount and nature of future capital, development, and exploration expenditures,*
- *the drilling of wells,*
- *reserve estimates and the estimates of both future net revenues and the present value of future net revenues that are included in their calculation,*
- *future oil and gas production estimates,*
- *repayment of debt,*
- *business strategies,*
- *expansion and growth of operations,*
- *recent legal developments, and*
- *other similar matters.*

These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments, and other factors we believe are appropriate under the circumstances. Such statements are subject to a number of assumptions, risks, and uncertainties, including such factors as the volatility and level of oil and natural gas prices, unexpected drilling conditions and results, production rates and reserve replacement, the imprecise nature of oil and gas reserve estimates, the risks of various exploration and hedging strategies, drilling and operating service availability and risks, uncertainties in cash flow, the financial strength of hedge contract counterparties, the availability of attractive exploration, development and property acquisition opportunities, financing requirements, expected acquisition benefits, competition, litigation, environmental matters, the potential impact of government regulations, the use of management estimates, and other matters discussed in the "Risk Factors" section of our 2005 Annual Report on Form 10-K. Readers are cautioned that forward-looking statements are not guarantees of future performance and that actual results or developments may differ materially from those expressed or implied in the forward-looking statements. Although we may from time to time voluntarily update our prior forward - looking statements, we disclaim any commitment to do so except as required by *securities laws.*

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this item is provided under the captions "Commodity Price Risk and Interest Rate Risk," "Summary of Oil and Gas Production Hedges in Place," and "Summary of Interest Rate Hedges in Place" in Item 2 above and is incorporated herein by reference.

ITEM 4. CONTROLS AND PROCEDURES

We maintain a system of disclosure controls and procedures that are designed to ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

We carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this Quarterly Report on Form 10-Q. Based upon that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures are effective for the purposes discussed above as of the end of the period covered by this Quarterly Report on Form 10-Q. There was no change in our internal control over financial reporting that occurred during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

From time to time, we may be involved in litigation relating to claims arising out of our operations in the normal course of business. As of the date of this report, no legal proceedings are pending against us that we believe individually or collectively could have a material adverse effect upon our financial condition or results of operations.

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors as previously disclosed in our Form 10-K for the year ended December 31, 2005, in response to Item 1A of Part I of such Form 10-K.

ITEM 6. EXHIBITS

The following exhibits are filed as part of this report:

Exhibit	Description
4.1	Second Amendment to the Shareholder Rights Plan, dated effective as of April 24, 2006
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
32.1	Certification pursuant to U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes – Oxley Act of 2002

SIGNATURES

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

ST. MARY LAND & EXPLORATION COMPANY

May 4, 2006 By: /s/ MARK A. HELLERSTEIN
Mark A. Hellerstein
President and Chief Executive Officer

May 4, 2006 By: /s/ DAVID W. HONEYFIELD
David W. Honeyfield
Vice President - Chief Financial Officer,
Secretary and Treasurer

May 4, 2006 By: /s/ GARRY A. WILKENING
Garry A. Wilkening
Vice President - Administration and
Controller

Exhibit 4.1

SECOND AMENDMENT

TO

SHAREHOLDER RIGHTS PLAN

This Second Amendment (the "Second Amendment") to the Shareholder Rights Plan (the "Plan") of St. Mary Land & Exploration Company, a Delaware corporation (the "Company"), is executed effective as of April 24, 2006.

RECITALS

WHEREAS, the Plan was established effective as of August 1, 1999 and was previously amended by a First Amendment to the Plan effective as of July 19, 2001;

WHEREAS, the Board of Directors of the Company has determined that it is in the best interests of the Company's stockholders to further amend the Plan as set forth in this Second Amendment; and

WHEREAS, capitalized terms used but not defined in this Second Amendment shall have the meanings previously given to them in the Plan.

NOW, THEREFORE**,** the Plan is hereby amended as follows:

AMENDMENT

1. Section 1(k) of the Plan is hereby amended in its entirety to read as follows:

"Final Expiration Date" shall mean December 31, 2011.

2. Section 1(r) of the Plan is hereby amended in its entirety to read as follows:

"Purchase Price" shall mean, from and after April 24, 2006, $140.00 per share of Common Stock and shall be subject to adjustment thereafter from time to time as provided in this Plan.

3. The first sentence of Section 3(a) of the Plan is hereby amended in its entirety to read as follows:

At any time after the Distribution Date and prior to the Expiration Date, the registered holder of any Right may exercise such Right by written notice to the Company of such exercise together with payment of the Purchase Price for the Common Share as to which such Right is exercised.

The remainder of the Plan shall be unaffected by this Second Amendment.

IN WITNESS WHEREOF, the Company has caused this Second Amendment to the Shareholder Rights Plan to be duly executed on its behalf on April 24, 2006.

ST. MARY LAND & EXPLORATION COMPANY,
a Delaware corporation

By: /S/ MARK A. HELLERSTEIN
Mark A. Hellerstein
Chairman of the Board, President and
Chief Executive Officer

Exhibit 31.1

CERTIFICATION

I, Mark A. Hellerstein, certify that:

1. I have reviewed this quarterly report on Form 10-Q of St. Mary Land & Exploration Company;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 3, 2006

/S/ MARK A. HELLERSTEIN

Mark A. Hellerstein
Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, David W. Honeyfield, certify that:

1. I have reviewed this quarterly report on Form 10-Q of St. Mary Land & Exploration Company;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 3, 2006

/S/ DAVID W. HONEYFIELD

David W. Honeyfield
Chief Financial Officer

Exhibit 32.1

CERTIFICATION
PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report on Form 10-Q of St. Mary Land & Exploration Company (the “Company”) for the quarterly period ended March 31, 2006 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Mark A. Hellerstein, as Chief Executive Officer of the Company, and David W. Honeyfield, as Chief Financial Officer of the Company, each hereby certifies, pursuant to and solely for the purpose of 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to the best of his knowledge and belief, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/S/ MARK A. HELLERSTEIN
Mark A. Hellerstein
Chief Executive Officer
May 3, 2006

/S/ DAVID W. HONEYFIELD
David W. Honeyfield
Chief Financial Officer
May 3, 2006