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 June 30, 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 (Address of principal executive offices)	**80203** (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 July 24, 2006, the registrant had 54,817,306 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)

	June 30, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,825	$ 14,925
Short-term investments	1,475	1,475
Accounts receivable	115,516	165,197
Refundable income taxes	18,332	—
Prepaid expenses and other	15,961	7,283
Accrued derivative asset	30,220	6,799
Deferred income taxes	—	8,252
Total current assets	183,329	203,931
Property and equipment (successful efforts method), at cost:		
Proved oil and gas properties	1,631,994	1,441,959
Less - accumulated depletion, depreciation, and amortization	(562,690)	(497,621)
Unproved oil and gas properties, net of impairment allowance of $9,690 in 2006 and $9,862 in 2005	52,522	44,383
Wells in progress	69,510	55,505
Other property and equipment, net of accumulated depreciation of $8,893 in 2006 and $8,046 in 2005	5,663	5,340
	1,196,999	1,049,566
Noncurrent assets:		
Goodwill	9,452	9,452
Long-term derivative asset	8,801	575
Other noncurrent assets	4,627	5,223
Total noncurrent assets	22,880	15,250
Total Assets	**$ 1,403,208**	**$ 1,268,747**
LIABILITIES AND STOCKHOLDERS' EQUITY		

Current liabilities:		
Accounts payable and accrued expenses	$ 160,423	$ 164,957
Accrued derivative liability	37,602	34,037
Deferred income taxes	1,673	—
Total current liabilities	199,698	198,994
Noncurrent liabilities:		
Long-term credit facility	51,000	—
Convertible notes	99,933	99,885
Asset retirement obligation	69,011	66,078
Net Profits Plan liability	157,904	136,824
Deferred income taxes	154,689	128,296
Accrued derivative liability	93,492	64,137
Other noncurrent liabilities	5,622	5,213
Total noncurrent liabilities	631,651	500,433
Commitments and contingencies		
Stockholders' equity:		
Common stock, $0.01 par value: authorized — 200,000,000 shares; issued: 58,310,668 shares in 2006 and 57,011,740 shares in 2005; outstanding, net of treasury shares: 54,781,228 shares in 2006 and 56,761,740 shares in 2005	583	570
Additional paid-in capital	152,649	123,278
Treasury stock, at cost: 3,529,440 shares in 2006 and 250,000 in 2005	(127,686)	(5,148)
Deferred stock-based compensation	—	(5,593)
Retained earnings	598,559	510,812
Accumulated other comprehensive loss	(52,246)	(54,599)
Total stockholders' equity	571,859	569,320
Total Liabilities and Stockholders' Equity	**$ 1,403,208**	**$ 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 June 30,		For the Six Months Ended June 30,	
	2006	2005	2006	2005
Operating revenues:				
Oil and gas production revenue	$ 177,957	$ 160,421	$ 362,022	$ 298,791
Oil and gas hedge gain (loss)	4,875	(2,086)	9,980	(526)
Marketed gas and other revenue	4,117	6,265	8,535	10,153
Gain (loss) on sale of proved properties	6,432	(26)	6,432	(26)
Total operating revenues	193,381	164,574	386,969	308,392
Operating expenses:				
Oil and gas production expense	43,278	30,188	84,492	62,347
Depletion, depreciation, amortization, and abandonment liability accretion	35,910	33,907	70,301	63,981
Exploration	15,319	9,699	26,106	16,782
Impairment of proved properties	—	—	1,289	—
Abandonment and impairment of unproved properties	1,262	1,819	2,448	3,689
General and administrative	10,429	7,481	21,215	13,467
Change in Net Profits Plan liability	14,059	12,175	21,080	16,396
Marketed gas system and other operating expense	3,248	6,310	9,006	9,949
Unrealized derivative loss	4,791	241	5,261	1,370
Total operating expenses	128,296	101,820	241,198	187,981
Income from operations	65,085	62,754	145,771	120,411
Nonoperating income (expense):				
Interest income	540	98	1,364	180
Interest expense	(1,549)	(2,274)	(2,928)	(4,218)
Income before income taxes	64,076	60,578	144,207	116,373
Income tax expense	(23,996)	(22,317)	(53,601)	(43,009)
Net income	**$ 40,080**	**$ 38,261**	**$ 90,606**	**$ 73,364**
Basic weighted-average common shares outstanding	57,082	56,960	57,157	57,095
Diluted weighted-average common shares outstanding	66,950	66,769	67,145	66,847

Basic net income per common share	**$ 0.70**	**$ 0.67**	**$ 1.59**	**$ 1.28**
Diluted net income per common share	**$ 0.61**	**$ 0.59**	**$ 1.38**	**$ 1.13**

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	—	—	—	—	—	—	90,606	—	90,606
Change in derivative instrument fair value	—	—	—	—	—	—	—	8,624	8,624
Reclassification to earnings	—	—	—	—	—	—	—	(6,271)	(6,271)
Total comprehensive income									92,959
Cash dividends declared, $0.05 per share	—	—	—	—	—	—	(2,859)	—	(2,859)
Treasury stock purchases	—	—	—	(3,319,300)	(123,108)	—	—	—	(123,108)
Issuance of Directors' shares from treasury	—	—	—	26,076	68	—	—	—	68
Issuance of common stock under Employee Stock Purchase Plan	12,917	—	404	—	—	—	—	—	404
Sale of common stock, including income tax benefit of stock option exercises	1,286,011	13	28,738	—	—	—	—	—	28,751
Adoption of Statement of Financial Accounting Standards No. 123R	—	—	(5,593)	—	—	5,593	—	—	—
Stock-based compensation expense	—	—	5,822	13,784	502	—	—	—	6,324
Balances, June 30, 2006	**58,310,668**	**$ 583**	**$ 152,649**	**(3,529,440)**	**$(127,686)**	**$ —**	**$ 598,559**	**$ (52,246)**	**$ 571,859**

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 Six Months Ended June 30, 2006	For the Six Months Ended June 30, 2005
Reconciliation of net income to net cash provided by operating activities:		
Net income	$ 90,606	$ 73,364
Adjustments to reconcile net income to net cash provided by operating activities:		
(Gain) loss on sale of proved properties	(6,432)	26
Depletion, depreciation, amortization, and abandonment liability accretion	70,301	63,981
Exploratory dry hole expense	3,640	2,102
Impairment of proved properties	1,289	—
Abandonment and impairment of unproved properties	2,448	3,689
Unrealized derivative loss	5,261	1,370
Change in Net Profits Plan liability	21,080	16,396
Stock-based compensation expense	6,392	2,301
Deferred income taxes	34,683	18,102
Other	(603)	(319)
Changes in current assets and liabilities:		
Accounts receivable	49,681	702
Refundable income taxes	(18,332)	(3,748)
Prepaid expenses and other	(8,678)	(2,381)
Accounts payable and accrued expenses	(20,748)	7,244
Income tax benefit from the exercise of stock options*	(14,236)	2,747
Net cash provided by operating activities	**216,352**	**185,576**

Cash flows from investing activities:		
Proceeds from sale of oil and gas properties	182	101
Capital expenditures	(181,565)	(134,800)
Acquisition of oil and gas properties	(4,771)	(35,145)
Deposits to short-term investments available-for-sale	—	(1,502)
Receipts from short-term investments available-for-sale	—	1,402
Other	22	(34)
Net cash used in investing activities	**(186,132)**	**(169,978)**
Cash flows from financing activities:		
Proceeds from credit facility	108,000	119,000
Repayment of credit facility	(57,000)	(105,000)
Income tax benefit from the exercise of stock options*	14,236	—
Proceeds from sale of common stock	14,919	6,455
Repurchase of common stock	(120,616)	(28,347)
Dividends	(2,859)	(2,863)
Other	—	(693)
Net cash used in financing activities	**(43,320)**	**(11,448)**
Net change in cash and cash equivalents	(13,100)	4,150
Cash and cash equivalents at beginning of period	14,925	6,418
Cash and cash equivalents at end of period	**$ 1,825**	**$ 10,568**

* SFAS 123R requires presentation of the income tax benefit from the exercise of stock options to be presented in financing activites subsequent to adoption. The prior period classification is to remain unchanged under SFAS 123R.

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 Six Months Ended June 30,	
	2006	2005
	(in thousands)	
Cash paid for interest, net of capitalized interest	$ 3,700	$ 3,944
Cash paid for income taxes	$29,373	$22,741

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

As of June 30, 2006 and 2005, $78.4 million and $40.4 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.

In May 2006 and 2005 the Company issued 26,076 and 13,926 shares, respectively, of common stock from treasury to its non-employee directors pursuant to the Company's non-employee director stock compensation plan. The Company recorded compensation expense related to the issuances of $195,000 and $25,500 for the six-month periods ended June 30, 2006 and 2005, respectively.

In May 2006 the Company closed a transaction whereby it exchanged oil and gas properties located in Richland County, Montana for non-core oil and gas properties. This transaction is considered a non-monetary exchange for accounting purposes with a fair value assigned to this transaction of $11.5 million.

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

June 30, 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 in the continental United States and offshore in the Gulf of Mexico.

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. 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.

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

Richland County, Montana Acquisition

On May 15, 2006, the Company closed on a transaction whereby it exchanged non-core oil and gas properties located in the Uinta Basin for oil and gas properties located in Richland County, Montana. The transaction was structured as an Internal Revenue Code Section 1031 tax-deferred exchange. For financial reporting purposes, the transaction is considered a non-monetary exchange and has been accounted for at estimated fair value. The exchange of properties resulted in recognition of a gain of approximately $6 million. The final purchase accounting allocation and gain determination will be dependent on finalization of post-closing adjustments associated with revenue, expenses, and costs incurred between the effective date and the date of closing. The Company expects that this allocation will be completed prior to the end of 2006.

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.

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.

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 non-discretionary 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 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 thereby 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 or 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 and six-month periods ended June 30, 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 June 30, 2006	For the Three Months Ended June 30, 2005	For the Six Months Ended June 30, 2006	For the Six Months Ended June 30, 2005
	(In thousands, except per share amounts)			
Net income	$ 40,080	$ 38,261	$ 90,606	$ 73,364
Adjustments to net income for dilution:				
Add: interest expense not incurred if Convertible Notes converted	1,580	1,580	3,142	3,142
Less: other adjustments	(16)	(16)	(31)	(31)
Less: income tax effect of adjustment items	(585)	(577)	(1,157)	(1,150)
Net income adjusted for the effect of dilution	$ 41,059	$ 39,248	$ 92,560	$ 75,325
Basic weighted-average common shares outstanding	57,082	56,960	57,157	57,095
Add: dilutive effects of stock options and unvested restricted stock units	2,176	2,117	2,296	2,060
Add: dilutive effect of Convertible Notes using if-converted method	7,692	7,692	7,692	7,692
Diluted weighted-average common shares outstanding	66,950	66,769	67,145	66,847
Basic earnings per common share	$ 0.70	$ 0.67	$ 1.59	$ 1.28
Diluted earnings per common share	$ 0.61	$ 0.59	$ 1.38	$ 1.11

Note 5 — Compensation Plans

Cash Bonus Plan

The Company has a cash bonus plan that allows participants to receive a bonus of 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 the 2004 performance year. The cash bonus expenses for the three-month periods ended June 30, 2006, and 2005, were $1.4 million and $928,000, respectively, and the cash bonus expenses for the six-month periods ended June 30, 2006, and 2005, were $2.7 million and $1.5 million, respectively.

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 recommended by senior management and designated as participants by the Company's Compensation Committee of the Board of Directors 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. Beginning with the 2006 pool, 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 June 30, 2006, and 2005, were $6.9 million and $4.9 million, respectively, and expenses related to current distributions for the six-month periods ended June 30, 2006, and 2005, were $13.8 million and $7.6 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. For a predominate number of the pools, a discount rate of 15 percent is used to calculate this liability 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 commodity price assumptions are currently formulated by applying a price that is derived from a rolling average of actual prices realized over the prior 24 months together with adjusted New York Mercantile Exchange, Inc., ("NYMEX") strip prices for the ensuing 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 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 into 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 commodity prices in the calculation were changed by ten percent, the liability recorded at June 30, 2006, would differ by approximately $33 million. A one percentage point change in the discount rate would result in a change of approximately $8 million. Actual cash payments to be made in future periods are dependent on realized actual production, prices, and costs associated with the properties in each individual pool 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 June 30,		For the Six Months Ended June 30,	
	2006	2005	2006	2005
	(In thousands)		(In thousands)	
Liability balance for Net Profits Plan as of the beginning of the period	$ 143,845	$ 34,782	$ 136,824	$ 30,561
Increase in liability	20,992	17,078	34,894	23,964
Reduction in liability for cash payments made or accrued and recognized as compensation expense	(6,933)	(4,903)	(13,814)	(7,568)
Liability balance for Net Profits Plan as of the end of the period	$ 157,904	$ 46,957	$ 157,904	$ 46,957

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 expense in the current period. The amount recorded as an 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 June 30,		For the Six Months Ended June 30,	
	2006	2005	2006	2005
	(In thousands)		(In thousands)	
General and administrative expense	$ 5,768	$ 5,989	$ 8,964	$ 8,131
Exploration expense	8,291	6,186	12,116	8,265
Total	$ 14,059	$ 12,175	$ 21,080	$ 16,396

Equity Incentive Compensation Plan

In May 2006, the stockholders approved the 2006 Equity Incentive Compensation Plan (the “2006 Plan”) to authorize the issuance of restricted stock, restricted stock units, non-qualified stock options, incentive stock options, stock appreciation rights, and stock based awards to key employees, consultants, and members of the Board of Directors of St. Mary or any affiliate of St. Mary. The 2006 Plan serves as the successor to the St. Mary Land & Exploration Company Stock Option Plan, the St. Mary Land & Exploration Company Incentive Stock Option Plan, the St. Mary Land & Exploration Company Restricted Stock Plan, and the St. Mary Land & Exploration Company Non-Employee Director Stock Compensation Plan (collectively referred to as the “Predecessor Plans”). All grants of equity are now made out of the 2006 Plan and no grants will be made under the Predecessor Plans. Each outstanding award under a Predecessor Plan immediately prior to the effective date of the 2006 Plan continues to be governed solely by the terms and conditions of the instruments evidencing such grants or issuances.

As of June 30, 2006, there were 2.6 million remaining shares of common stock available for grant under the 2006 Plan. Under the 2006 Plan, any issuances of a direct share benefit such as an outright grant of common stock, a grant of a restricted share or a restricted stock unit counts as two shares against the amount eligible to be granted under the 2006 Plan. Each stock option and similar instrument granted counts as one share against the eligible shares authorized to be issued under the 2006 Plan.

St. Mary anticipates granting restricted stock and restricted stock units under the 2006 Plan for the foreseeable future. The Company does however have outstanding stock option grants under the previous stock option plans. The following sections describe the details of restricted stock units and stock options outstanding as of June 30, 2006.

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 six months ended June 30, 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.

Restricted Stock Incentive Program

The Company has a long-term incentive program whereby grants of restricted stock or restricted stock units (“RSUs”) have been 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.

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 June 30, 2006, there was a total of 1,117,075 RSUs outstanding, of which 552,111 were vested. Total compensation expense related to the RSUs for the three-month periods ended June 30, 2006, and 2005, were $2.7 million and $1.3 million, respectively, and total compensation expense related to the RSUs for the six-month periods ended June 30, 2006, and 2005, were $5.3 million and $2.3 million, respectively. The 2006 period includes $1.1 million of compensation expense for the estimated value of grants expected to be issued in 2007 related to the 2006 performance year.

As part of hiring a new senior executive in the second quarter of 2006, St. Mary granted a special common stock award of 20,000 shares which vested immediately upon commencement of employment. Approximately $737,000 of compensation expense was recorded related to this award. In addition to this award, the employee may earn an additional 20,000 shares contingent on the Company meeting certain performance conditions. The fair value of this award will be recorded to compensation expense over the vesting period. As of June 30, 2006, approximately $7,000 of compensation expense had been recorded related to the contingent award.

A summary of the status and activity of non-vested RSUs for the period ended June 30, 2006, is presented below.

	Shares	Weighted-Average Grant-Date Fair Value
Non-vested, at beginning period	356,550	$ 18.92
Granted	504,351	$ 33.92
Vested	(295,852)	$ 25.12
Forfeited	(85)	$ 25.12
Non-vested, at end of period	564,964	$ 28.66

In measuring compensation expense from the grant of RSUs, SFAS No. 123R requires companies to estimate the fair value of the award on the grant date. The fair value of RSUs has been measured 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 granted RSUs were estimated using the following weighted-average assumptions:

	For the Six Months Ended June 30,	
	2006	2005
Risk free interest rate:	4.70%	4.03%
Dividend yield:	0.68%	0.40%
Volatility factor of the expected marketprice 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 $5.6 million related to outstanding RSU awards was reclassified to additional paid-in-capital within the shareholders' equity section of the balance sheet. 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 amortized to compensation expense over the vesting period. SFAS No. 123R requires expense recognized subsequent to the adoption date to be based on fair value.

Stock Option Grants

The Company has previously granted stock options under the St. Mary Land & Exploration Company Stock Option Plan. The last issuance of stock options was December 31, 2004. Stock options to purchase shares of the Company's common stock have been issued to eligible employees and members of the Board of Directors. 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.

During the six-month period ended June 30, 2006, the Company recognized stock-based compensation expense of approximately $1.0 million 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, $14.2 million of excess tax benefits for the six months ended June 30, 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 June 30, 2006, and 2005, were $12.5 million and $2.9 million, respectively, and cash received from option exercises under all share-based payment arrangements for the six-month periods ended June 30, 2006, and 2005, were $14.5 million and $6.2 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 periods indicated:

	For the Three Months Ended June 30, 2005	For the Six Months Ended June 30, 2005
	(In thousands, except per share amounts)	
Net income —		
As reported:	$ 38,261	$ 73,364
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	783	1,435
Less: Stock-based employee compensation expense determined under fair value-based method for all awards, net of related income tax effects	(1,319)	(2,455)
Pro forma net income	$ 37,725	$ 72,344

Basic net income per share —				
As reported	$	0.67	$	1.28
Pro forma	$	0.66	$	1.27
Diluted net income per share —				
As reported	$	0.59	$	1.13
Pro forma	$	0.58	$	1.11

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 (the "ESPP") grants has been measured at the date of grant using the Black-Scholes option-pricing model. No options were granted during the six-month periods ended June 30, 2006, and 2005. For the employee stock purchase plan offering period January 1, 2006, through June 30, 2006, the Company has expensed $117,566 based on the estimated fair value on the date of grant.

The following table summarizes the stock options outstanding as of June 30, 2006, as well as activity during the six 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	(1,286,011)	$	11.29			
Outstanding at end of period	3,412,232	$	12.55	5.86	$	94,509
Exercisable at end of period	2,970,538	$	12.40	5.68	$	82,741

As of June 30, 2006, there was $1.2 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.

Note 6 - Income Taxes

Income tax expense for the three-month and six-month periods ended June 30, 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.

The Company's current portion of income tax expense for the three-month periods ended June 30, 2006, and 2005, were $3.1 million and $14.5 million, respectively, and the current portion of income tax expense for the six-month periods ended June 30, 2006, and 2005, were $18.9 million and $24.9 million, respectively. The Company's effective tax rates for the three-month periods ended June 30, 2006, and 2005, were 37.4 percent and 36.9 percent, respectively, and the effective tax rates for the six-month periods ended June 30, 2006, and 2005, were 37.2 percent and 37.0 percent, respectively. 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 2006 Texas legislation instituting a new Margin Tax that will be effective for future tax periods and different impacts of acquisition and drilling activity between periods. 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 voluntarily limited by the Company 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%	³50%<75%	³75%<90%	³90%
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 $51 million in loans outstanding under its revolving credit agreement as of June 30, 2006.

5.75% Senior Convertible Notes Due 2022

As of June 30, 2006, the Company 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 and six-month periods ended June 30, 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 three-month periods ended June 30, 2006, and 2005, were 8.1 percent and 6.9 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 weighted-average interest rates paid for the six-month periods ended June 30, 2006 and 2005, were 8.2 percent and 7.0 percent, respectively. Capitalized interest costs for the Company for the three-month periods ended June 30, 2006, and 2005 were $704,000 and $445,000, respectively, and capitalized interest costs for the six-month periods ended June 30, 2006, and 2005, were $1.4 million and $842,000, respectively.

Note 8 — Derivative Financial Instruments

The Company recognized a net gain of $83,000 from its derivative contracts for the three-month period ended June 30, 2006, compared to a net loss of $2.3 million for the same period in 2005. Comparative amounts for the six months ended June 30, 2006, and 2005, were a net gain of $4.4 million and a net loss of $1.9 million, respectively.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2006	2005	2006	2005
Derivative contract settlements realized in oil and gas hedge gain (loss)	$ 4,875	$ (2,086)	$ 9,980	$ (526)
Ineffective portion of hedges qualifying for hedge accounting included in unrealized derivative loss	(4,918)	(409)	(5,754)	(1,023)
Non-qualified derivative contracts included in unrealized derivative loss	126	168	493	(347)
Interest rate derivative contract settlements	—	—	(275)	28
Total	$ 83	$ (2,327)	$ 4,444	$ (1,868)

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 June 30, 2006, the Company has hedge contracts in place through 2011 for a total of approximately 11 million Bbls and 84 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 June 30, 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 Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities ("SFAS No. 133"), was a net liability of $91.5 million at June 30, 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.

Unrealized derivative loss for the three-month periods ended June 30, 2006, and 2005, were a net loss of $4.9 million and $409,000, respectively, from the ineffective portion of oil and natural gas derivative contracts. Amounts for the six-month periods ended June 30, 2006, and 2005, were net losses of $5.8 million and $1.0 million, respectively.

As of June 30, 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 $4.4 million.

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 $383,000 as of June 30, 2006. The Company recorded net derivative gain in the consolidated statements of operations of $130,000 for the three-month period ended June 30, 2006, and a net gain of $201,000 for the three-month period ended June 30, 2005, from mark-to-market adjustments for these derivatives. Comparative amounts for the six-month periods ended June 30, 2006, and 2005, were a net gain of $262,000 and a net derivative loss of $475,000, respectively. These derivatives 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 three-month period includes $24,000 of amortization of this derivative. Derivative gain in the consolidated statements of operations for the three-month periods ended June 30, 2006, and 2005, were net losses of $4,000 and $33,000, respectively. Comparative amounts for the six-month periods ended June 30, 2006, and 2005, includes a net gain of $231,000 and $128,000, respectively, from mark-to-market adjustments for this derivative. The fair value of this derivative was a liability of $238,000 at June 30, 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 "Non-qualified 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 Non-qualified Pension Plan:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2006	2005	2006	2005
	(In thousands)		(In thousands)	
Service cost	$ 421	$ 346	$ 842	$ 693
Interest cost	163	134	326	267
Expected return on plan assets	(107)	(94)	(190)	(188)
Amortization of net actuarial loss	74	60	148	120
Net periodic benefit cost	$ 551	$ 446	$ 1,126	$ 892

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 contributed $1.3 million to the Qualified Pension Plan during the second quarter of 2006. No further contributions are planned for the remainder of 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 June 30,		For the Six Months Ended June 30,	
	2006	2005	2006	2005
	(In thousands)		(In thousands)	
Beginning asset retirement obligation	$ 67,196	$ 43,462	$ 66,078	$ 40,911
Liabilities incurred	1,203	230	1,758	2,399
Liabilities settled	(573)	(36)	(1,162)	(359)
Accretion expense	1,185	727	2,337	1,432
Ending asset retirement obligation	$ 69,011	$ 44,383	$ 69,011	$ 44,383

Note 11 — Repurchase of Common Stock

Stock Repurchase Program

During the second quarter of 2006 St. Mary repurchased 3,319,300 shares of its common stock. As of June 30, 2006, the Company had the authority to repurchase 526,818 shares under the stock repurchase program. Subsequent to June 30, 2006, the Company's Board of Directors approved an increase in the number of shares that may be repurchased under the Company's authorized share repurchase program by an additional 5,473,182 shares. Accordingly, as of the date of this filing the Company has Board authorization to repurchase an additional six million shares of common stock. 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. Additionally, in July 2006, the Company's Board of Directors approved a resolution to retire 3,275,689 shares of treasury stock.

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 90 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 and limestone 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 NYMEX natural gas price decreased by 25 percent and the NYMEX oil price increased 11 percent between the first quarter and second quarter of 2006. We believe that the historically high volumes of natural gas in storage caused by a relatively warm winter pressured the spot NYMEX natural gas price downwards over the course of the quarter. Throughout the quarter, however, most of our operating regions saw improvements in basis differentials in both absolute and percentage terms. The three year NYMEX strip at June 30, 2006 was $8.74 per MMBtu and $74.57 per Bbl compared to $10.09 per MMBtu and $63.01 per Bbl at December 31, 2005. Geopolitical tensions pressed NYMEX crude prices upward throughout the quarter. In July, NYMEX crude oil reached an all-time high as tensions in the Middle East continued to increase. Domestically, we saw the first quarter basis differential on Rockies crude oil moderate in the second quarter. The improvement is primarily due to refineries increasing activity for the summer driving season throughout the quarter as well as greater asphalt production.

For the three months ended June 30, 2006, our realized natural gas and oil prices, including the impacts of hedges, were $6.96 per Mcf and $59.62 per Bbl, respectively, and for the six months ended June 30, 2006, our realized natural gas and oil prices, including the impacts of hedges, were $7.59 per Mcf and $56.96 per Bbl, respectively. These prices compare to average NYMEX prices of $6.82 per MMBtu and $70.70 per Bbl for the three months ended June 30, 2006, and $7.95 per MMBtu and $67.09 per Bbl for the six months ended June 30, 2006. Excluding the effects of hedging our realized natural gas and oil prices for the three months ended June 30, 2006, were $6.20 per Mcf and $63.68 per Bbl, respectively, and for the six months ended June 30, 2006, our realized natural gas and oil prices, excluding the effects of hedging, were $6.86 per Mcf and $60.22 per Bbl, respectively. Our natural gas price realizations for the three months ended June 30, 2006, were improved by $10.7 million of realized hedging gains while our oil price realization was negatively impacted by $5.8 million of realized hedging losses. For the six months ended June 30, 2006, our natural gas price realizations were improved by $19.6 million of realized hedging gains and our oil price realization was negatively impacted by $9.6 million of realized hedging losses.

Cost Environment

Cost escalation in the service sector continues to affect our business. Increases in rig rates, field service costs, workover costs, and materials prices continue to pressure the exploration and production sector. Historically, cost changes have lagged commodity prices, both on upward and downward price trends. Compounding the current situation is the scarcity of equipment and services in many of our regions. We believe 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. Although the spot NYMEX natural gas price has decreased over the quarter, the NYMEX future natural gas strip price has decreased to a lesser extent. Because of commodity price volatility, we evaluate current economics on an individual investment basis prior to proceeding with making investment decisions. We have a formal process for establishing our drilling budget, however, 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 exploration and development budget for 2006 is $477 million and we have budgeted $100 million for acquisitions. The current budget reflects the timing of drilling projects which have been impacted by service availability issues, timing of permitting, and the postponement of selected projects due to unfavorable economics given the current price and cost environment. We contemplated the current cost environment in constructing our current drilling budget.

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 were a supplement to our previous swap and collar contracts. We also hedged a portion of specific forecasted natural gas production for 2006 and 2007 using swap contracts. Additionally, we hedged anticipated production in conjunction with the recent execution of our stock repurchase program for a commensurate amount of reserves that were represented by the proportionate number of total outstanding shares repurchased. Taking into account all oil and gas production hedge contracts placed to date, we have hedged approximately 11 million Bbls and 84 million MMBtu of our anticipated production through the year 2011. Overall we have hedged an estimated 58 percent of our remaining 2006 forecast oil production volumes and 37 percent of our remaining 2006 forecast natural gas production volumes using both zero-cost collars and swap contracts. Using current differentials, we estimate that the break-even NYMEX prices for these commodity derivatives are approximately $54.31 per Bbl and $8.51 per MMBtu over the remainder of 2006. Primarily because of the basis expansion affecting oil in the Rockies, we recorded approximately $4.9 million of ineffectiveness related to our derivative contracts in the second quarter of 2006. However we continue to have adequate correlation to maintain these derivatives as cash flow hedges. 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.

Execution of Share Repurchase Program

During the quarter ended June 30, 2006, we repurchased 3,319,300 shares of our common stock in the open market. The weighted average price for these repurchases was $37.09 per share including commissions. As of the end of June 2006, we had 526,818 shares remaining for authorized repurchase. Subsequent to the close of the quarter, our Board authorized an increase in the number of shares available for repurchase under the plan to a total of six million shares thereby increasing the number of shares that were available to be repurchased under the program by an additional 5,473,182 shares. Management plans to continue to evaluate the repurchase of common stock as a part of our business plan.

We evaluate the market price of our common stock relative to our assessment of net asset value per share. To the extent the market price is sufficiently below what we believe to be the net asset value per share, we will repurchase shares under the program. The repurchase activity was funded using cash on hand and bank borrowings. As a result, we had $51 million in outstanding borrowings under our credit facility as of quarter-end.

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 June 2006 financial statements has increased by $21.1 million. We have also expensed $6.9 million and $13.8 million of compensation costs associated with the cash payments for the Net Profits Plan for the three-month and six-month periods ended June 30, 2006. This amount is slightly lower than originally budgeted due to increased capital spending in existing payout pools, an increase in the timing of payout for newer pools, and a 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 $32 million for cash payments to be made for the 2006 period. The actual cash payments made are dependent on actual production, realized prices, and operating and capital costs associated with the properties in each individual pool. 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* section below.

The calculation of the estimated liability associated with the Net Profits Plan requires management to prepare an 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 estimates are forecasted oil and gas production from the properties that comprise each individual pool, price assumptions, cost 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 an average of actual prices realized over the prior 24 months together with adjusted NYMEX strip prices for the ensuing 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 commodity prices in our calculation by ten percent, the liability recorded at June 30, 2006, would differ by approximately $33 million. A one percentage point change in the discount rate would result in a change of approximately $8 million. We frequently evaluate the assumptions used in our calculations to evaluate the possible impacts stemming from the current market environment, including current and future 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 with future restricted stock units to be granted under the Equity Incentive Compensation Plan. We adopted SFAS No. 123R using the modified-prospective transition method. Our consolidated financial statements as of and for the three-months and six-months ended June 30, 2006, reflect the impact of SFAS No. 123R. Total stock-based compensation expense for the three and six-month periods ended June 30, 2006, was approximately $3.4 million and

$6.6 million, respectively, which included $576,000 and $1.1 million, respectively, of expenses related to stock options and employee stock purchases under the ESPP recognized under SFAS No. 123R. Upon adoption of SFAS No. 123R, we have expensed all costs associated with those individuals that do not have a future service requirement due to their existing term of service to us and their age.

As part of hiring a new senior executive, we granted a special stock award of 20,000 shares which vested immediately upon commencement of employment. Approximately $737,000 of compensation expense was recorded related to this award. In addition to this award the employee may earn an additional 20,000 shares contingent on certain performance conditions. The fair value of this award will be recorded to compensation expense over the vesting period. As of June 30, 2006, approximately $7,000 of compensation expense had been recorded related to this award.

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 on January 1, 2006, we selected the Black-Scholes option pricing model to determine the estimated fair value for stock-based awards.

Second Quarter 2006 Highlights

Our second quarter net income was $40.1 million or $0.61 per diluted share compared to 2005 results of $38.3 million or $0.59 per diluted share. Production for the second quarter was 22.6 BCFE. This represents a four percent increase from the same period a year ago and a three percent increase from the previous quarter. Per MCFE lease operating expense and transportation expense increased $0.41 to $1.37 as compared to a year ago. We are seeing increased lease operating expense in every region compared to last year due to a combination of increased equipment and service cost and more workover activity. The increase in commodity prices over the past several years has led to increased levels of new drilling activity, as well as providing an incentive to perform maintenance on wells and infrastructure which may not have been performed in a lower commodity price environment. While the demand for equipment and services has increased dramatically, the available supply from vendors has not increased as quickly. Accordingly, equipment and service providers have been able to raise their prices in a period where we were increasing our activity. With respect to workovers, we saw activity increase as we repaired and upgraded properties associated with recent acquisitions in the Rockies. Additionally, we had several high-dollar operations on a few high-value properties in the Mid-Continent, Gulf Coast, and the Rockies. Production taxes increased $0.12 to $0.54 per MCFE, and DD&A, including ARO accretion expense, increased $0.03 to $1.59 per MCFE. We discuss these financial results and trends in more detail below.

The table below provides information regarding selected production and financial information for the quarter ended June 30, 2006, and the immediately preceding three quarters. Additional detail of per MCFE cost is contained later in this section.

	For the Three Months Ended			
	June 30, 2006	March 31, 2006	December 31, 2005	September 30, 2005
	(In millions, except production sales data)			
Production sales (BCFE)	22.6	22.0	21.9	23.1
Oil and gas production revenues before the effects of hedging	$ 178.0	$ 184.1	$ 231.6	$ 203.1
Lease operating expense	$ 28.3	$ 26.3	$ 23.8	$ 22.9
Transportation costs	$ 2.8	$ 2.9	$ 2.6	$ 1.8
Production taxes	$ 12.2	$ 12.0	$ 16.1	$ 13.4
General and administrative expense	$ 10.4	$ 10.8	$ 9.5	$ 9.8
Net income	$ 40.1	$ 50.5	$ 51.2	$ 27.3
Percentage change from previous quarter:				
Production (MCFE)	3%	—%	(5)%	6%
Oil and gas production revenues before the effects of hedging	(3)%	(21)%	14%	27%
Lease operating expense	8%	11%	4%	19%
Transportation costs	(3)%	12%	44%	—%
Production taxes	2%	(25)%	20%	46%
General and administrative expense	(4)%	14%	(3)%	31%
Net income	(21)%	(1)%	88%	(29)%

On May 15, 2006, we closed on a transaction whereby we exchanged non-core oil and gas properties located in the Uinta Basin for oil and gas properties located in Richland County, Montana. The transaction was structured as an Internal Revenue Code Section 1031 tax-deferred exchange. For financial reporting purposes, the transaction is considered a non-monetary transaction and has been accounted for at estimated fair value, effectively resulting in the exchange being considered a sale and a purchase of oil and gas properties. The exchange of properties resulted in recognition of a gain of approximately $6 million.

First Six Months 2006 Highlights

In the first six months of 2006 our net income was $90.6 million or $1.38 per diluted share compared to 2005 income of $73.4 million or $1.13 per diluted share. Production for the first six months was 44.6 BCFE. This represents a five percent increase from the same period a year ago. Per MCFE lease operating expense and transportation expense increased $0.34 to $1.36 as compared to a year ago. This increase over the last year's comparable period is due to increased costs and higher levels of workover activity. An increase in commodity prices over the past several years has led to increased levels of drilling and maintenance activity. Service and equipment providers have struggled to keep up with the increase in demand, and have been able to increase prices for their goods and services. In addition to the higher costs we are incurring on base levels of activity, we also have been actively repairing properties in the Rockies associated with transactions we completed in 2005. Production taxes increased $0.09 to $0.54 per MCFE, and DD&A, including ARO accretion expense, increased $0.07 to $1.58 per MCFE. We discuss these financial results and trends in more detail below.

Outlook for the Remainder of 2006

While oil and gas prices remain highly volatile, we have an inventory of drilling prospects that is attractive in various price environments. We believe we will continue to have access to the drilling rigs we currently operate. Adding new rigs may remain a challenge because of the competitive state of the rig market. The ability of drilling rig companies to hire qualified crews may impact our ability to drill wells. We continue to realize the impact of escalating rig and other service costs, particularly in marginal gas projects where economics have been pressured as natural gas prices declined due to historically high natural gas storage. Robust oil prices, on the other hand, are resulting in superior returns and cash flow on oil properties.

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 also reflects the strides we have made to advance our prospect inventory and drilling activity level. We continue to maintain a disciplined approach to acquisitions as we actively evaluate acquisition opportunities and the potential impact such transactions will have on net asset value per share. Over the remainder of 2006 we will continue to execute our business plan, including the following:

- *Rockies Conventional* — In the second quarter, we successfully completed 27 wells in the Rockies, with one dry hole. In the Bakken, five wells were completed successfully during the quarter with four wells completing and two wells drilling as of quarter-end. We continue to exploit the Bakken using a combination of grass roots drilling and re-entry wells. Despite recent industry reports promoting the prospectivity of the North Dakota Bakken, we continue to be disappointed with the results we see there and accordingly are not actively drilling farther east of the Montana/North Dakota state line. We plan to participate in more than 30 wells in the Bakken in 2006. We also plan to continue taking advantage of our expertise in the Red River formation and to drill wells exploring the potential of a horizontal program in the Madison formation.

- *Rockies — Hanging Woman Basin Coalbed Natural Gas* — As of this filing, we have drilled a total of 296 wells in our Hanging Woman Basin coalbed natural gas project, of which 216 wells are currently producing. We plan to drill over 140 wells during 2006. Production for the project is currently approximately 10.5 MMCFD gross, 7.0 MMCFD net.

  We plan on drilling two to four horizontal wells to test the deeper Roberts and Kendrick coals later this summer. Horizontal completion techniques have successfully been used in similar coals in Oklahoma and Australia. With respect to permitting wells on federal acreage in Montana, the supplemental environmental impact statement required by the Ninth Circuit Court of Appeals is anticipated to be completed in June of 2007. The state of Montana however continues to issue permits for wells on state and fee acreage.

- *Mid-Continent* — As of the end of the first six months of 2006 we have completed five horizontal Cromwell sandstone wells, two horizontal Woodford shale wells, and one Wapanucka limestone well in the Centrahoma area. We are currently operating two rigs and are participating in one non-operated rig. We plan to participate in the drilling of approximately 36, 19 of which we will operate, horizontal wells in the Centrahoma area during 2006.

  In Northeast Mayfield, we successfully completed four wells during the second quarter. Seven wells are completing and five wells are drilling as of the end of the second quarter. We operate two drilling rigs in the field. As the Atoka/Granite Wash program at Northeast Mayfield is sensitive to natural gas prices, we hedged approximately two-thirds of the production of our anticipated 2006 drilling program to protect our economics. We continue to evaluate the economics of proposed wells before drilling to ensure the wells meet minimum economic thresholds, although non-economic factors such as rig utilization for operated rigs are also considered in that decision.

The Paggi Broussard #2 well, which is an offset well to the Paggi Broussard #1 well at our Constitution field recently completed drilling. The well began production in July with initial gross production of 14.6 MMCF and 810 Bbls of condensate per day.

- *ArkLaTex* — During the second quarter, we successfully completed 16 wells in the region, with one dry hole and two unsuccessful completions. We continue to see improvements as a result of improved stimulation techniques at Spider field. There are five wells planned in Spider in the second half of the year. In Elm Grove, development is advancing southward onto acreage where we have higher working interests. Thirty wells are budgeted in Elm Grove for the second half of the year where two non-operated rigs are running in this field.

- *Gulf Coast and Permian* — The SML 27-1, Viceroy, targeting the Rob L1 sand on our fee lands in St. Mary Parrish, Lousiana is currently drilling. At Judge Digby, we experienced a successful new well and two successful recompletions during the first half of the year. A second well, the Ivy Major #6, has recently been completed and is producing 10 MMCF per day.

- We continue to 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 growth includes production from budgeted acquisitions and is a result of anticipated success in our drilling programs.

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

Selected Operations Data (In Thousands, Except Price and Per MCFE Amounts):

	For the Three Months Ended June 30, 2006	For the Three Months Ended June 30, 2005	% of Change Between Periods	For the Six Months Ended June 30, 2006	For the Six Months Ended June 30, 2005	% of Change Between Periods
Net production volumes						
Natural gas (Mcf)	14,023	13,184	6%	26,812	25,231	6%
Oil (Bbl)	1,429	1,428	—%	2,957	2,862	3%
MCFE (6:1)	22,595	21,754	4%	44,556	42,401	5%
Average daily production						
Natural gas (MMcf per day)	154	145	6%	148	139	6%
Oil (MBbl per day)	16	16	-%	16	16	3%
MMCFE per day (6:1)	248	239	4%	246	234	5%
Oil & gas production revenues(1)						
Gas production	$ 97,669	$ 89,220	9%	$ 203,560	$ 164,111	24%
Oil production	85,163	69,115	23%	168,442	134,154	26%
Total	$ 182,832	$ 158,335	15%	$ 372,002	$ 298,265	25%
Oil & gas production expense						
Lease operating expenses	$ 28,292	$ 19,162	48%	$ 54,624	$ 39,398	39%
Transportation costs	2,748	1,813	52%	5,595	3,693	51%
Production taxes	12,238	9,213	33%	24,273	19,256	26%
Total	$ 43,278	$ 30,188	43%	$ 84,492	$ 62,347	36%
Average realized sales price(1)						
Natural gas (per Mcf)	$ 6.96	$ 6.77	3%	$ 7.59	$ 6.50	17%
Oil (per Bbl)	$ 59.62	$ 48.39	23%	$ 56.96	$ 46.88	22%
Per MCFE Data:						
Average net realized price(1)	$ 8.09	$ 7.28	11%	$ 8.35	$ 7.03	19%
Lease operating expense	(1.25)	(0.88)	42%	(1.23)	(0.93)	32%
Transportation costs	(0.12)	(0.08)	50%	(0.13)	(0.09)	44%
Production taxes	(0.54)	(0.42)	29%	(0.54)	(0.45)	20%
General and administrative	(0.46)	(0.34)	35%	(0.48)	(0.32)	50%
Operating profit	$ 5.72	$ 5.56	3%	$ 5.97	$ 5.24	14%
Depletion, depreciation and amortization, and abandonment liability accretion	$ 1.59	$ 1.56	2%	$ 1.58	$ 1.51	5%

(1) Includes the effects of our hedging activities

Financial Information (In Thousands, Except Per Share Amounts):

	June 30, 2006	December 31, 2005	% of Change Between Periods
Working Capital (Deficit)	$ (16,369)	$ 4,937	(432)%
Long-Term Debt	$ 150,933	$ 99,885	51%
Stockholders' Equity	$ 571,859	$ 569,320	—%

	For the Three Months Ended June 30, 2006	For the Three Months Ended June 30, 2005	% of Change Between Periods	For the Six Months Ended June 30, 2006	For the Six Months Ended June 30, 2005	% of Change Between Periods
Basic Weighted-Average Shares Outstanding	57,082	56,960	—%	57,157	57,095	—%
Diluted Weighted-Average Shares Outstanding	66,950	66,769	—%	67,145	66,847	—%
Basic Net Income Per Common Share	$ 0.70	$ 0.67	4%	$ 1.59	$ 1.28	24%
Diluted Net Income Per Common Share	$ 0.61	$ 0.59	3%	$ 1.38	$ 1.13	22%

The preceding tables are presented as summaries 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 service cost increases annually 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. 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 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 the actual borrowing base is substantially greater than $500 million, however, we have not requested a borrowing base amount that exceeds the note amount. 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 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. Our loan balance of $51 million on June 30, 2006, was comprised of $33 million of Euro-dollar based borrowing and $18 million of ABR borrowing. As of July 26, 2006, our total outstanding borrowings under the credit facility had been reduced to $45 million of Euro-dollar based borrowing and $2 million of ABR borrowing. As of June 30, 2006, we had a cash and short-term investment balance of $3.3 million.

Our weighted-average interest rate paid in the first six 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 six months of 2006 we spent $186.3 million on oil and gas development and exploration costs using cash flows from operations. We also made cash payments for income taxes of $29.4 million. We estimate that approximately 35 to 40 percent of our total income tax liability for 2006 will result in cash taxes that are payable on a current basis.

During the second quarter of 2006, we purchased 3,319,300 shares of our common stock for a total of $123.1 million. All but $2.5 million of this amount was paid out during the second quarter. This remaining amount settled subsequent to the quarter. 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, compliance with securities laws, and the terms and provisions of our stock repurchase program.

During the second quarter of 2006, we paid $2.9 million in dividends to our stockholders. Our intention is to continue to make dividend payments for the foreseeable future subject to our future earnings, our financial condition, possible credit facility covenants, and other currently unexpected factors that could arise.

The following table presents amounts and percentage changes in cash flows between the six-month periods ending June 30, 2006, and June 30, 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 Six Months Ended June 30, 2006	2005	Change	Percent Change
	(In thousands)			
Net cash provided by operating activities	$ 216,352	$ 185,576	$ 30,776	17%
Net cash used in investing activities	$ (186,132)	$ (169,978)	$ (16,154)	10%
Net cash used by financing activities	$ (43,320)	$ (11,448)	$ (31,872)	278%

Analysis of cash flow changes between the six months ended June 30, 2006, and June 30, 2005

Operating activities. Cash received from oil and gas sales, net of the effects of hedging, increased $10.4 million to $311.2 million for the six-month period ended June 30, 2006, from $300.8 million for the six-month period ended June 30, 2005. This increase was the result of a five percent increase in production and a 19 percent increase in our net realized prices between the two periods. Net cash payments made for income taxes increased $7.0 million. The future operating cash flow impact on the 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, increased $46.8 million, or 35 percent, and cash outflow related to the acquisition of oil and gas properties decreased $30.4 million, or 86 percent, compared to the same period in 2005.

Financing activities. We received $8.5 million more from the sale of our common stock from the exercise of stock options and shares issued under the ESPP, had a $14.2 million increase in income tax benefit from the exercise of stock options, and received $37 million more in proceeds from our credit facility in the second quarter of 2006 compared to the same period in 2005. These amounts were offset by an increase of $92.3 million spent in order to repurchase common stock on the open market under our stock repurchase plan in the second quarter of 2006 compared with the same period in 2005.

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)	Gross Well Count
Mid-Continent region	$ 175	110
Rocky Mountain region	135	164
ArkLaTex region	72	90
Gulf Coast region	56	16
Coalbed natural gas	32	146
Permian Basin region	7	11
	$ 477	537

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 Six Months Ended June 30, 2006	2005
	(In thousands)	
Development costs	$ 147,599	$ 112,338
Exploration costs	73,425	31,346
Acquisitions:		
Proved	16,149	39,563
Unproved	—	2,178
Leasing activity	13,944	7,596
Total, including asset retirement obligation	$ 251,117	$ 193,021

The costs we incurred for capital and exploration activities during the first six months of 2006 increased $58.1million or 30 percent compared to the same period in 2005. Excluding acquisitions, our development and exploration spending has increased $77.3 million compared to the same six-month period in the prior year.

We believe that internally generated cash flows together with the cash available under 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 may 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 risks, including the effects of changes in oil and gas commodity prices and changes in interest rates as discussed below and under the captions *Summary of Oil and Gas Production Hedges in Place* and *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 June 30, 2006. As of June 30, 2006, our hedged positions totaled 11 million Bbls and 84 million MMBtu of anticipated future production through 2011. We seek to minimize basis risk

and therefore, the majority of our oil contracts are indexed to NYMEX prices and our gas contracts to various regional index prices associated with pipelines in proximity to our areas of gas sales.

Oil Contracts

Oil Swaps

Contract Period	Volumes (Bbl)	Weighted-Average Contract Price (Per Bbl)	Fair Value at June 30, 2006 Asset/(Liability) (In thousands)
Third quarter 2006			
NYMEX WTI	281,372	$ 54.79	$ (5,605)
IF Bow River	33,000	$ 40.46	(581)
Fourth quarter 2006			
NYMEX WTI	155,686	$ 50.57	(3,882)
IF Bow River	30,000	$ 37.54	(415)
2007			
NYMEX WTI	314,786	$ 39.78	(10,758)
IF Bow River	76,000	$ 38.85	(1,093)
2008			
NYMEX WTI	35,000	$ 56.63	(557)
All oil swap contracts			$ (22,891)

Oil Collars

Contract Period	NYMEX WTI Volumes (Bbl)	Weighted-Average Floor Price (Per Bbl)	Weighted-Average Ceiling Price (Per Bbl)	Fair Value at June 30, 2006 Asset/(Liability) (In thousands)
Third quarter 2006	648,000	$ 52.10	$ 72.66	$ (2,551)
Fourth quarter 2006	739,000	$ 52.23	$ 72.76	(4,875)

2007	2,897,000	$ 51.59	$ 72.78		(22,533)
2008	1,668,000	$ 50.00	$ 69.82		(14,822)
2009	1,526,000	$ 50.00	$ 67.31		(13,808)
2010	1,367,500	$ 50.00	$ 64.91		(12,247)
2011	1,236,000	$ 50.00	$ 63.70		(10,482)
All oil collars				$	(81,318)

Gas Contracts

Gas Swaps

Contract Period	Volumes (MMBtu)	Weighted-Average Contract Price (Per MMBtu)	Fair Value at June 30, 2006 Asset/(Liability) (In thousands)
Third quarter 2006			
IF ANR OK	1,740,000	$ 8.51	$ 5,574
IF PEPL	1,290,000	$ 5.33	100
IF CIG	930,000	$ 5.77	758
IF NGPL	580,000	$ 9.94	2,700
IF CenterPoint	360,000	$ 5.67	73
IF HSC	60,000	$ 6.53	44
Fourth quarter 2006			
IF ANR OK	1,020,000	$ 9.06	2,935
IF PEPL	1,070,000	$ 6.78	93
IF CIG	1,080,000	$ 6.47	44
IF NGPL	550,000	$ 10.24	1,857
IF CenterPoint	160,000	$ 5.71	(79)
IF HSC	80,000	$ 7.93	52
2007			
IF ANR OK	1,640,000	$ 9.22	1,873
IF NGPL	3,280,000	$ 9.16	3,684
IF CIG	3,750,000	$ 7.37	(110)
IF PEPL	3,840,000	$ 8.35	1,332
IF HSC	530,000	$ 8.63	45
2008			
IF CIG	3,120,000	$ 7.48	218
IF PEPL	3,840,000	$ 8.51	2,156
IF HSC	300,000	$ 8.84	5
2009			
IF CIG	1,710,000	$ 7.79	788
IF PEPL	1,920,000	$ 8.35	710
All gas swap contracts			$ 24,852

Gas Collars

Contract Period	Volumes (MMBtu)	Weighted-Average Floor Price (Per MMBtu)	Weighted-Average Ceiling Price (Per MMBtu)	Fair Value at June 30, 2006 Asset/(Liability) (In thousands)
Third quarter 2006				
IF ANR OK	450,000	$ 6.92	$ 9.28	$ 756
IF PEPL	720,000	$ 7.27	$ 13.54	1,485
IF CIG	210,000	$ 7.00	$ 11.52	437
IF HSC	430,000	$ 7.71	$ 13.80	856
NYMEX Henry Hub	330,000	$ 8.00	$ 14.50	624
Fourth quarter 2006				

IF ANR OK	100,000	$ 7.00	$ 9.82	173
IF PEPL	655,000	$ 7.89	$ 14.07	1,082
IF CIG	390,000	$ 7.23	$ 12.51	555
IF HSC	400,000	$ 8.10	$ 14.20	650
NYMEX Henry Hub	270,000	$ 8.63	$ 15.54	377
2007				
IF PEPL	7,960,000	$ 7.35	$ 10.74	1,947
IF CIG	3,120,000	$ 6.66	$ 9.36	97
IF HSC	1,240,000	$ 7.84	$ 10.60	89
NYMEX Henry Hub	790,000	$ 8.28	$ 11.32	(33)
2008				
IF PEPL	6,600,000	$ 6.28	$ 9.42	(2,347)
IF CIG	2,880,000	$ 5.60	$ 8.72	(1,371)
IF HSC	960,000	$ 6.57	$ 9.70	(480)
NYMEX Henry Hub	480,000	$ 7.00	$ 10.57	(220)
2009				
IF PEPL	5,510,000	$ 5.30	$ 9.25	(3,159)
IF CIG	2,400,000	$ 4.75	$ 8.82	(1,195)
IF HSC	840,000	$ 5.57	$ 9.49	(554)
NYMEX Henry Hub	360,000	$ 6.00	$ 10.35	(195)
2010				
IF PEPL	4,945,000	$ 5.31	$ 7.61	(3,879)
IF CIG	2,040,000	$ 4.85	$ 7.08	(1,539)
IF HSC	600,000	$ 5.57	$ 7.88	(533)
NYMEX Henry Hub	240,000	$ 6.00	$ 8.38	(195)
2011				
IF PEPL	4,225,000	$ 5.31	$ 6.51	(3,751)
IF CIG	1,800,000	$ 5.00	$ 6.32	(1,242)
IF HSC	480,000	$ 5.57	$ 6.77	(429)
NYMEX Henry Hub	120,000	$ 6.00	$ 7.25	(100)
All gas collars				$ (12,094)

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

We have various interest rate derivative contracts which are represented by offsetting trades that have fixed the future payments under these contracts. The fair value of the interest rate derivatives was a liability of $383,000 as of June 30, 2006. We recorded a net derivative gain in the consolidated statements of operations of $130,000 for the three-month period ended June 30, 2006, compared with a net gain of $201,000 for the same period in 2005, from mark to market adjustment for these derivatives. Comparative amounts for the six-month periods ended June 30, 2006, and 2005, were a net gain of $262,000 and a net derivative loss of $475,000, respectively. These derivatives 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. We had floating-rate debt of $51 million outstanding as of June 30, 2006 and 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	$ 155.7	$ —	$ —	$ 51.0	$ 104.7
Operating Leases	8.7	2.3	4.3	1.2	0.9
Other Long-Term Liabilities	52.2	6.5	19.1	21.0	5.6
Total	$ 216.6	$ 8.8	$ 23.4	$ 73.2	$ 111.2

This table includes our 2006 estimated pension liability payment of approximately $1.6 million expected to be paid in the second quarter of 2007, but excludes the remaining unfunded portion of our estimated pension liability of $960,000 since we cannot determine with accuracy the timing of future payments.

The table also includes estimated net oil and natural gas derivative payments of $41.3 million based on futures market prices as of June 30, 2006. This amount represents the intrinsic value of our swap and collar arrangements and differs in amount from our recorded fair value, which as of June 30, 2006, was a net liability of $91.5 million. Both the intrinsic value and fair value will change as oil and natural gas commodity prices change. Please refer to the discussion above under the caption *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 and to Note 8 — Derivative Financial Instruments in Part I, Item 1 of this report for additional information regarding our oil and gas hedges.

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.

Four 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.

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 notes to our consolidated financial statements included in Part I, Item 1 of this report.

Additional Comparative Data in Tabular Form:

Oil and gas production revenues	Change Between the Three Months Ended June 30, 2006, and 2005	Change Between the Six Months Ended June 30, 2006, and 2005
Increase in oil and gas production revenues, net of hedging (in thousands)	$ 24,497	$ 73,737

Components of Revenue Increases (Decreases):

Natural Gas		
Realized price change per Mcf	$ 0.19	$ 1.09
Realized price percentage change	3 %	17 %
Production change (MMcf)	839	1,581
Production percentage change	6 %	6 %
Oil		
Realized price change per Bbl	$ 11.23	$ 10.08
Realized price percentage change	23 %	22 %
Production change (MBbl)	1	95
Production percentage change	— %	3 %

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
Revenue	2006	2005	2006	2005
Natural gas	53%	56%	55%	55%
Oil	47%	44%	45%	45%
Production				
Natural gas	62%	61%	60%	60%
Oil	38%	39%	40%	40%

Information Regarding the Components of Exploration Expense:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
Summary of Exploration Expense (in millions)	2006	2005	2006	2005
Geological and geophysical expenses	$ 2.5	$ 1.5	$ 4.0	$ 3.5
Exploratory dry hole expense	3.4	1.9	3.6	2.1
Overhead and other expenses	9.4	6.3	18.5	11.2
Total	$ 15.3	$ 9.7	$ 26.1	$ 16.8

Information Regarding the Effects of Oil and Gas Hedging Activity:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
Natural Gas Hedging	2006	2005	2006	2005

Percentage of gas production hedged	38%	21%	39%	21%
Natural gas MMBtu hedged	5.7 million	3.0 million	11.2 million	5.8 million
Increase (decrease) in gas revenue	$ 10.7million	$ (112,000)	$ 19.6 million	$ 3.7 million
Average realized gas price per Mcf before hedging	$ 6.20	$ 6.78	$6.86	$ 6.36
Average realized gas price per Mcf after hedging	$ 6.96	$ 6.77	$7.59	$ 6.50
Oil Hedging				
Percentage of oil production hedged	72%	18%	68%	17%
Oil volumes hedged (MBbl)	1,026	258	2,025	501
Decrease in oil revenue	$ (5.8 million)	$ (2.0 million)	$ (9.6 million)	$ (4.2 million)
Average realized oil price per Bbl before hedging	$ 63.68	$ 49.77	$ 60.22	$ 48.35
Average realized oil price per Bbl after hedging	$ 59.62	$ 48.39	$ 56.96	$ 46.88

Comparison of Financial Results and Trends between the Quarters ended June 30, 2006, and 2005

Oil and gas production revenue. Average net daily production increased four percent to 248.3 MMCFE per day for the second quarter of 2006, compared with 239.1 MMCFE per day for the same quarter in 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	1.9	$ 3.3	$ 0.8
Other wells completed in 2005 and 2006	52.3	19.1	2.7
Wold acquisition	5.5	4.1	2.3
Total	59.7	$ 26.5	$ 5.8

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 $13.1 million, or 43 percent, to $43.3 million for the second quarter of 2006 from $30.2 million in the comparable period of 2005. Total oil and gas production costs per MCFE increased $0.53 to $1.91 for the second quarter of 2006, compared with $1.38 for the same quarter in 2005. This increase is comprised of the following:

· A $0.12 increase in overall production taxes, of which $0.08 was related to higher natural gas revenues from our Mid-Continent region and $0.02 was due to higher revenue from crude oil in our Rocky Mountain and Permian regions;

· A $0.04 increase in overall transportation cost which was comprised of a $0.07 increase in the Rocky Mountain region thatwas partially off set by decreases in the other regions;

· A $0.16 increase in recurring LOE related to a continued increase in competition for oil and gas service sector resources;

· A $0.21 overall increase in LOE relating to workover costs, due to a significant increase in workover activity in the Rockies.

General and administrative. General and administrative expenses increased $2.9 million, or 39 percent, to $10.4 million for the second quarter of 2006, compared with $7.5 million for the comparable period of 2005. G&A increased $0.12 to $0.46 per MCFE for the second quarter of 2006 compared to $0.34 per MCFE for the same quarter in 2005 as G&A grew at a faster rate than the four percent increase in production.

A 16 percent increase in employee count has contributed to an increase in base employee compensation of approximately 18 percent, or $860,000, between the second quarter of 2006 and the second quarter of 2005. The current period realized expense associated with the Net Profits Plan has increased by $2.0 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 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 second quarter 16 of our 19 pools are currently in payout status. No additional pools are expected to reach payout during 2006.

RSU bonus expense is $1.4 million higher for the second quarter of 2006 than in the same quarter in 2005, which is partially caused by the increase in amortization of expense associated with stock-based compensation expense. We are recording expense covering four periods of RSU grants compared with only three issuances at this same time last year. Additionally, the increase in RSU bonus expense for the second quarter ended June 30, 2006, compared with the same period in 2005 reflects an evaluation of our overall performance based on an evaluation of reserve replacement, production increases, and net asset value per share growth. Furthermore, an increase in the estimated bonus percentage resulted in an increase in the cash bonus expense of approximately $500,000 to $1.4 million for the quarter ended June 30, 2006, compared with $900,000 for the quarter ended June 30, 2005. As a result of the implementation of SFAS No. 123R on January 1, 2006, we recorded approximately $600,000 of compensation expense related to stock options and the ESPP, which is not comparable to the prior year.

The above increases combined with a net $1.2 million increase in other G&A expense, including payroll tax and 401(k) contribution expense, were offset by a $2.9 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 and an $800,000 increase in COPAS overhead reimbursements. COPAS overhead reimbursements from operations increased due to an increase in our operated well count from our drilling program.

Exploration Expense. Exploration expense increased $5.6 million, or 58 percent, to $15.3 million for the second quarter of 2006, compared with $9.7 million for the comparable period of 2005. The increase is partially related to an approximate $1.4 million increase in payments made under the Net Profits Plan, as well as an approximated $1.5 million increase in general exploration overhead due to the increase in the size of our geologic and exploration staff. Additionally, the increase in exploration expense is also partially explained by a $1.5 million increase in exploratory dry hole expense.

Change in Net Profits Plan Liability. For the second quarter of 2006, this non-cash expense increased $1.9 million to $14.1 million from $12.2 million for the same quarter in 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 $24.0 million for the second quarter of 2006 and $22.3 million for the second quarter of 2005 resulting in effective tax rates of 37.4 percent and 36.9 percent, respectively. The effective rate change from 2005 reflects changes in the mix of the highest marginal state tax rates as a result of enacted Texas margin tax legislation, acquisition and drilling activity and also reflects other permanent differences including differing estimated effects between years of the domestic production activities deduction.

Comparison of Financial Results and Trends between the six months ended June 30, 2006 and 2005

Oil and gas production revenue. Average net daily production increased five percent to 246.2 MMCFE per day for the six months ended June 30, 2006, compared with 234.3 MMCFE per day for the six months ended June 30, 2005. The following table presents specific components that contributed to the increase in revenue between the two periods:

	Average Net Daily Production Added (MMCFE)	Oil and Gas Revenue Added (In millions)	Production Costs Added (In millions)
Williston Basin Middle Bakken Play	3.5	$ 8.2	$ 1.1
Other wells completed in 2005 and 2006	42.2	42.5	5.5
Wold acquisition	5.3	7.8	4.4
Total	51.0	$ 58.5	$ 11.0

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 resulting 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 $22.2 million, or 36 percent, to $84.5 million for the six months ended June 30, 2006, from $62.3 million for the six months ended June 30, 2005. Total oil and gas production costs per MCFE increased $0.43 to $1.90 for the six months ended June 30, 2006, compared with $1.47 for the six months ended June 30, 2005. This increase is comprised of the following:

· A $0.09 increase in production taxes, comprised mainly of a $0.06 increase in our Mid-Continent region resulting from higher natural gas revenues;

· A $0.04 increase in overall transportation cost which was comprised of a $0.05 increase in the Rocky Mountain region that was partially off set by decreases in the other regions;

· A $0.16 increase in recurring LOE related to continued increases in competition for oil and gas service sector resources and;

· A $0.14 overall increase in LOE relating to workover charges, due to an $0.11 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 $7.7 million, or 58 percent, to $21.2 million for the six months ended June 30, 2006, compared with $13.5 million for the six months ended June 30, 2005. G&A increased $0.16 to $0.48 per MCFE for the six months ended June 30, 2006 compared to $0.32 per MCFE for the six months ended June 30, 2005 as G&A grew at a faster rate than the five percent increase in production.

A 16 percent increase in employee count has contributed to an increase in base employee compensation of approximately 18 percent, or $1.7 million, between the six-month period of 2006 and the six-month period 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 $6.2 million in 2006 compared with the same period in 2005.

RSU bonus expense is $3.0 million higher for the six months ended June 30, 2006, than in the same six months in 2005, which is partially 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. Additionally, the increase in RSU bonus expense for the six month period ended June 30, 2006, compared with the same period in 2005 reflects an evaluation of our overall performance based on an evaluation of reserve replacement, production increases, and net asset value per share growth. Furthermore the increase in the bonus percentage resulted in an increase in the cash bonus expense of $1.2 million to $2.7 million for the six months ended June 30, 2006, compared with $1.5 million for the six months ended June 30, 2005.

As a result of the implementation of SFAS No. 123R on January 1, 2006, we recorded $1.1 million of compensation expense related to stock options and the ESPP. The above increases combined with a net $3.1 million increase in other G&A expense, including payroll tax and 401(k) contribution expense, were offset by a $6.9 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 and a $1.7 million increase in COPAS overhead reimbursements. COPAS overhead reimbursements from operations increased due to an increase in our operated well count from our drilling program.

Exploration Expense. Exploration expense increased $9.3 million, or 56 percent, to $26.1 million for the six month period ended June 30, 2006, compared with $16.8 million for the comparable period of 2005. The increase is partially related to an approximate $3.9 million increase in payments made under the Net Profits Plan, as well as an approximated $3.2 million increase in general exploration overhead due to the increase in the size of our geologic and exploration staff. Additionally, the increase in exploration expense is partially related to a $1.5 million increase in exploratory dry hole expense.

Change in Net Profits Plan Liability. For the six months ended June 30, 2006, this non-cash expense increased $4.7 million to $21.1 million from $16.4 million for the six months ended June 30, 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 $53.6 million for the six months ended June 30, 2006, and $43.0 million for the six months ended June 30, 2005, resulting in effective tax rates of 37.2 percent and 37.0 percent, respectively. The effective rate change from 2005 reflects changes in the mix of the highest marginal state tax rates as a result of enacted Texas margin tax legislation, 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*" contained 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 disclosures.

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.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

(c) The following table provides information about purchases by the Company during the fiscal quarter ended June 30, 2006, of shares of the Company's common stock, which is the sole class of equity securities registered by the Company pursuant to Section 12 of the Exchange Act.

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased (1)	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Program (2)	(d) Maximum Number of Shares that May Yet Be Purchased Under the Program (2)
04/01/06 — 04/30/06	- 0 -	$ - 0 -	- 0 -	3,846,118
05/01/06 — 05/31/06	1,273,900	$ 37.15	1,273,900	2,572,218
06/01/06 — 06/30/06	2,051,616	$ 37.05	2,045,400	526,818
Total:	3,325,516	$ 37.09	3,319,300	526,818

(1) Includes 6,216 shares delivered to the Company by an employee in satisfaction of withholding taxes in connection with the issuance of stock under the St. Mary Land & Exploration Company 2006 Equity Incentive Compensation Plan.

(2) Subsequent to June 30, 2006, the Company's Board of Directors approved an increase in the number of shares that may be repurchased under the Company's authorized share repurchase program by an additional 5,473,182 shares. Accordingly, as of the date of this filing the Company has Board authorization to repurchase six million shares of common stock on a prospective basis. 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 bank credit facility agreement and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flow, and borrowings under St. Mary's bank credit facility. The stock repurchase program may be suspended or discontinued at any time.

The payment of dividends and stock repurchases are subject to covenants in our bank credit facility, including the requirement that we maintain certain levels of stockholders' equity and the limitation of our annual dividend rate to no more than $0.25 per share.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

At the Company's annual stockholders' meeting on May 17, 2006, the stockholders elected management's current slate of directors. Each director was elected by a majority vote. The directors elected and the vote tabulation for each director was as follows:

Director	For	Withheld
Barbara M. Baumann	51,055,923	679,893
Larry W. Bickle	51,055,784	680,032
Thomas E. Congdon	51,179,181	556,635
William J. Gardiner	51,566,784	169,032
Mark A. Hellerstein	51,205,940	529,876
John M. Seidl	50,245,215	1,490,601
William D. Sullivan	51,394,798	341,018

Also at the Company's annual stockholders' meeting on May 17, 2006, the stockholders approved a proposal to approve the 2006 Equity Incentive Compensation Plan as the successor plan to the St. Mary Land & Exploration Company Stock Option Plan, the St. Mary Land & Exploration Company Incentive Stock Option Plan, the St. Mary Land & Exploration Company Restricted Stock Plan, and the St. Mary Land & Exploration Company Non-Employee Director Stock Compensation Plan; and increase the number of shares of stock available for issuance to employees. The proposal was approved by a majority vote. The tabulation of votes for that proposal was as follows:

For	39,919,312
Against	4,840,783
Abstain	2,120,559
Not Voted	4,855,190

The stockholders also approved the proposal to ratify the appointment by the Audit Committee of Deloitte & Touche, LLP as the Company's Independent Registered Public Accounting Firm. The proposal was approved by a majority vote. The tabulation of votes for that proposal was as follows:

For	51,640,426
Against	74,888
Abstain	20,502
Not Voted	28

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 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on April 25, 2006 and incorporated herein by reference).
10.1	Copy of the Employment Agreement of Mr. A.J. Best dated May 1, 2006 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on May 4, 2006 and incorporated herein by reference).
10.2	St. Mary Land & Exploration Company 2006 Equity Incentive Compensation Plan (filed on May 17, 2006 as Exhibit 99.1 to the registrant's Registration Statement on Form S-8 (Registration No. 333-134221) and incorporated herein by reference)
10.3	Form of St. Mary Land & Exploration Company Non-Employee Director Restricted Stock Award Agreement (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on May 18, 2006 and incorporated herein by reference).
10.4	Summary of Compensation Arrangements for Non-employee Directors as amended on May 18, 2006 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on May 22, 2006 and incorporated herein by reference).
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

* Filed with this Form 10-Q

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

August 3, 2006	By:	/s/ MARK A. HELLERSTEIN Mark A. Hellerstein Chief Executive Officer
August 3, 2006	By:	/s/ DAVID W. HONEYFIELD David W. Honeyfield Vice President — Chief Financial Officer, Secretary and Treasurer
August 3, 2006	By:	/s/ GARRY A. WILKENING Garry A. Wilkening Vice President — Administration and Controller

Exhibit 31.1

**CEO CERTIFICATIONS FOR
SECOND QUARTER FORM 10-Q**

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

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: August 3, 2006

/s/ MARK A. HELLERSTEIN
Mark A. Hellerstein
Chief Executive Officer

Exhibit 31.2

CFO CERTIFICATIONS FOR
SECOND QUARTER 2006 FORM 10-Q

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: August 2, 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 June 30, 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
August 3, 2006

/s/ DAVID W. HONEYFIELD
David W. Honeyfield
Chief Financial Officer
August 2, 2006