ST MARY LAND & EXPLORATION CO
Form 10-Q
August 03, 2007

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, 2007

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 x No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer x Accelerated filer o Non-accelerated filer o

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

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 31, 2007, the registrant had 63,444,934 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, 2007	December 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 26,179	$ 1,464
Short-term investments	1,143	1,450
Accounts receivable	137,333	142,721
Refundable income taxes	6,908	7,684
Prepaid expenses and other	21,587	17,485
Accrued derivative asset	29,454	56,136
Total current assets	222,604	226,940
Property and equipment (successful efforts method), at cost:		
Proved oil and gas properties	2,320,523	2,063,911
Less - accumulated depletion, depreciation, and amortization	(709,217)	(630,051)
Unproved oil and gas properties, net of impairment allowance of $9,790 in 2007 and $9,425 in 2006	110,471	100,118
Wells in progress	150,765	97,498
Other property and equipment, net of accumulated depreciation of $10,734 in 2007 and $9,740 in 2006	8,487	6,988
	1,881,029	1,638,464
Noncurrent assets:		
Goodwill	9,452	9,452
Accrued derivative asset	4,932	16,939
Other noncurrent assets	13,614	7,302
Total noncurrent assets	27,998	33,693
Total Assets	**$ 2,131,631**	**$ 1,899,097**
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 226,080	$ 171,834
Short-term note payable		4,469
Accrued derivative liability	24,669	13,100
Deferred income taxes	2,713	14,667
Total current liabilities	253,462	204,070
Noncurrent liabilities:		
Long-term credit facility	96,000	334,000
Senior convertible notes	287,500	99,980
Asset retirement obligation	81,205	77,242
Net Profits Plan liability	164,388	160,583
Deferred income taxes	246,508	224,518
Accrued derivative liability	95,480	46,432

Other noncurrent liabilities	8,284	8,898
Total noncurrent liabilities	979,365	951,653
Commitments and contingencies		
Stockholders equity:		
Common stock, $0.01 par value: authorized 200,000,000 shares; issued: 63,648,218 shares in 2007 and 55,251,733 shares in 2006; outstanding, net of treasury shares: 63,424,510 shares in 2007 and 55,001,733 shares in 2006	636	553
Additional paid-in capital	156,022	38,940
Treasury stock, at cost: 223,708 shares in 2007 and 250,000 shares in 2006	(3,350)	(4,272)
Retained earnings	791,269	695,224
Accumulated other comprehensive income (loss)	(45,773)	12,929
Total stockholders equity	898,804	743,374
Total Liabilities and Stockholders Equity	**$ 2,131,631**	**$ 1,899,097**

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

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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, 2007	2006	For the Six Months Ended June 30, 2007	2006
Operating revenues:				
Oil and gas production revenue	$ 216,154	$ 177,957	$ 409,860	$ 362,022
Realized oil and gas hedge gain	7,303	4,875	25,987	9,980
Marketed gas system revenue	15,967	3,167	23,826	9,234
Gain on sale of proved properties		6,432		6,432
Other revenue	7,730	950	8,487	(699)
Total operating revenues	247,154	193,381	468,160	386,969
Operating expenses:				
Oil and gas production expense	50,328	43,278	102,648	84,492
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	54,657	35,910	103,616	70,301
Exploration	13,643	15,319	34,412	26,106
Impairment of proved properties				1,289
Abandonment and impairment of unproved properties	1,465	1,262	2,949	2,448
General and administrative	13,697	10,429	24,838	21,215
Change in Net Profits Plan liability	(1,160)	14,059	3,805	21,080
Marketed gas system expense	14,940	2,829	22,176	8,016
Unrealized derivative loss	1,200	4,791	5,104	5,261
Other expense	401	419	1,117	990
Total operating expenses	149,171	128,296	300,665	241,198
Income from operations	97,983	65,085	167,495	145,771
Nonoperating income (expense):				
Interest income	154	540	257	1,364
Interest expense	(3,750)	(1,549)	(9,803)	(2,928)
Income before income taxes	94,387	64,076	157,949	144,207
Income tax expense	(35,152)	(23,996)	(58,764)	(53,601)
Net income	**$ 59,235**	**$ 40,080**	**$ 99,185**	**$ 90,606**
Basic weighted-average common shares outstanding	63,583	57,082	60,316	57,157
Diluted weighted-average common shares outstanding	65,120	66,950	65,015	67,145
Basic net income per common share	**$ 0.93**	**$ 0.70**	**$ 1.64**	**$ 1.59**
Diluted net income per common share	**$ 0.91**	**$ 0.61**	**$ 1.54**	**$ 1.38**

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

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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, 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							190,015		190,015
Change in derivative instrument fair value								87,107	87,107
Reclassification to earnings								(18,129)	(18,129)
Minimum pension liability adjustment								(180)	(180)
Total comprehensive income									258,813
SFAS No. 158 transition amount								(1,270)	(1,270)
Cash dividends, $ 0.10 per share							(5,603)		(5,603)
Treasury stock purchases				(3,319,300)	(123,108)				(123,108)
Retirement of treasury stock	(3,275,689)	(33)	(122,598)	3,275,689	122,631				
Issuance of common stock under Employee Stock Purchase Plan	26,046		814						814
Sale of common stock, including income tax benefit of stock option exercises	1,489,636	16	32,970						32,986
Adoption of Statement of Financial Accounting Standards No. 123(R)			(5,593)			5,593			
Stock-based compensation expense			10,069	43,611	1,353				11,422
Balances, December 31, 2006	**55,251,733**	**$ 553**	**$ 38,940**	**(250,000)**	**$ (4,272)**	**$**	**$ 695,224**	**$ 12,929**	**$ 743,374**

Comprehensive income, net of tax:									
Net income							99,185		99,185
Change in derivative instrument fair value								(42,380)	(42,380)
Reclassification to earnings								(16,319)	(16,319)
Minimum pension liability adjustment								(3)	(3)
Total comprehensive income									40,483
Cash dividends, $ 0.05 per share							(3,140)		(3,140)
Issuance of common stock under Employee Stock Purchase Plan	14,622		455						455
Conversion of 5.75% Senior Convertible Notes due 2022 to common stock, including income tax benefit of conversion	7,692,295	77	107,160						107,237
Issuance of common stock upon settlement of RSUs following expiration of restriction period, net of shares used for tax withholdings	302,370	3	(4,569)						(4,566)
Sale of common stock, including income tax benefit of stock option exercises	385,948	3	8,679						8,682
Stock-based compensation expense	1,250		5,357	26,292	922				6,279
Balances, June 30, 2007	**63,648,218**	**$ 636**	**$ 156,022**	**(223,708)**	**$ (3,350)**	**$**	**$ 791,269**	**$ (45,773)**	**$ 898,804**

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

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ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(In thousands)

	For the Six Months Ended June 30,	
	2007	**2006**
Reconciliation of net income to net cash provided by operating activities:		
Net income	$ 99,185	$ 90,606
Adjustments to reconcile net income to net cash provided by operating activities:		
Gain on insurance settlement	(6,325)	
Gain on sale of proved properties		(6,432)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	103,616	70,301
Exploratory dry hole expense	11,220	3,640
Impairment of proved properties		1,289
Abandonment and impairment of unproved properties	2,949	2,448
Unrealized derivative loss	5,104	5,261
Change in Net Profits Plan liability	3,805	21,080
Stock-based compensation expense	6,279	6,392
Deferred income taxes	52,457	34,683
Other	(2,696)	(603)
Changes in current assets and liabilities:		
Accounts receivable	12,507	49,681
Refundable income taxes	775	(18,332)
Prepaid expenses and other	(5,120)	(8,678)
Accounts payable and accrued expenses	2,327	(20,748)
Income tax benefit from the exercise of stock options	(3,762)	(14,236)
Net cash provided by operating activities	**282,321**	**216,352**
Cash flows from investing activities:		
Proceeds from insurance settlement	7,049	
Proceeds from sale of oil and gas properties	324	182
Capital expenditures	(278,983)	(181,565)
Acquisition of oil and gas properties	(31,050)	(4,771)
Deposits to short-term investments available-for-sale	(1,138)	
Receipts from short-term investments available-for-sale	1,450	
Other	17	22
Net cash used in investing activities	**(302,331)**	**(186,132)**
Cash flows from financing activities:		
Proceeds from credit facility	292,914	108,000
Repayment of credit facility	(530,914)	(57,000)
Repayment of short-term note payable	(4,469)	
Income tax benefit from the exercise of stock options	3,762	14,236
Proceeds from issuance of convertible debt	281,194	
Proceeds from sale of common stock	5,378	14,919
Repurchase of common stock		(120,616)
Dividends paid	(3,140)	(2,859)
Net cash provided by (used in) financing activities	**44,725**	**(43,320)**
Net change in cash and cash equivalents	24,715	(13,100)
Cash and cash equivalents at beginning of period	1,464	14,925
Cash and cash equivalents at end of period	**$ 26,179**	**$ 1,825**

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

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ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

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

	For the Six Months Ended June 30, 2007	2006
	(In thousands)	
Cash paid for interest, net of capitalized interest	$ 11,405	$ 3,700
Cash paid for income taxes	$ 1,184	$ 29,373

As of June 30, 2007, and 2006, $110.6 million and $78.4 million, respectively, are included as additions to oil and gas properties and as increases in 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 May 2007 and 2006 the Company issued 26,292 and 26,076 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 these issuances of $726,000 and $195,000 for the six-month periods ended June 30, 2007, and 2006, respectively.

In March 2007, the Company called the 5.75% Senior Convertible Notes for redemption. The note holders elected to convert the 5.75% Senior Convertible Notes to common stock. As a result, the Company issued 7,692,295 shares of common stock on March 16, 2007, in exchange for the $100 million of 5.75% Senior Convertible Notes. The conversion was executed in accordance with the conversion provisions of the original indenture. Additionally, the conversion resulted in a $7.0 million decrease in non-current deferred income taxes and a corresponding increase in additional paid-in capital that is a result of the recognition of the cumulative excess tax benefit earned by the Company associated with the contingent interest feature of this note.

In June 2006 the Company hired a new senior executive. In doing so, the Company issued 13,784 shares of stock and recorded compensation expense of approximately $728,000. Additionally, in March 2007 the Company issued 1,250 shares of stock to the senior executive as the Company reached certain performance levels. The Company has recognized approximately $69,000 of expense related to this issuance as of June 30, 2007.

In February 2007 and 2006, the Company issued 78,657 and 484,351 restricted stock units, respectively, pursuant to the Company s Restricted Stock Plan. The total value of the issuances were $2.5 million and $16.4 million, 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.

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

June 30, 2007

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/A for the year ended December 31, 2006. 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/A for the year ended December 31, 2006, 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/A for the year ended December 31, 2006.

Note 3 Acquisitions

Catarina Field Acquisition

On June 1, 2007, the Company acquired oil and gas properties located in the Catarina Field in Webb County, Texas in exchange for $29.0 million of cash. The Company allocated $28.9 million to proved and unproved oil and gas properties. The net difference between cash exchanged and the amount allocated to oil and gas properties was allocated to other assets. The Company allocated the purchase price based on the estimated fair value of the assets and liabilities acquired. The final purchase price will be adjusted for normal net purchase price adjustments and is expected to be finalized during the fourth quarter of 2007. The acquisition was accounted for using the purchase method, and was funded with cash on hand and borrowings under the Company s credit facility.

Permian Basin, Texas Acquisition

On December 14, 2006, the Company acquired oil and gas properties in the Permian Basin in West Texas from private parties in exchange for $247.4 million of cash. After normal net purchase price

adjustments of approximately $4.3 million, $239.8 million was allocated to proved and unproved oil and gas properties and $3.0 million was allocated to intangible assets. The net difference between cash exchanged and the amount allocated to oil and gas properties and intangible assets was allocated to other assets. The Company allocated the purchase price based on the estimated fair value of the assets and liabilities acquired. The acquisition was accounted for using the purchase method, and was funded with cash on hand and borrowings under the Company s credit facility.

Richland County, Montana Acquisition

On May 15, 2006, the Company closed on a transaction whereby it exchanged 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 was accounted for at estimated fair value. The exchange of properties resulted in recognition of approximately $6.4 million of gain.

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 (RSUs) 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. Prior to the conversion of the Company s 5.75% Senior Convertible Notes due 2022 (the 5.75% Convertible Notes) on March 16, 2007, potentially dilutive shares associated with this instrument were accounted for using the if-converted method for the determination of diluted earnings per share. Adjusted net income as used in the if-converted method was derived by adding interest expense paid on the 5.75% Convertible Notes back to net income and then adjusting for nondiscretionary items that are based on net income and would have changed had the 5.75% Convertible Notes been converted at the beginning of the period. The Company s 3.50% Senior Convertible Notes due 2027 (the 3.50% Convertible Notes) have a net-share settlement right, and the treasury stock method is used to measure the potentially dilutive impact of shares associated with the conversion feature. Year-to-date diluted earnings per share was calculated using shares associated with the 5.75% Convertible Notes, accounted for using the if-converted method as described above. Approximately 7.7 million potentially dilutive shares related to the 5.75% Convertible Notes were included in the calculation of diluted earnings per share for the three- and six-month periods ended June 30, 2006. The 5.75% Convertible Notes were called for redemption by the Company on March 16, 2007, and all of the note holders elected to convert the notes to shares of the Company s common stock. The Company issued 7,692,295 common shares in connection with the conversion of the 5.75% Convertible Notes. The diluted earnings per share calculation for the six-month period ended June 30, 2007, was adjusted for the conversion and included a time-weighted average of approximately 3.1 million potentially dilutive shares related to the 5.75% Convertible Notes. No potentially diluted shares related to the 5.75% Convertible Notes were included in the three-month period ended June 30, 2007.

Potentially dilutive securities for the year-to-date diluted earnings per share calculation consist of in-the-money outstanding stock options to purchase the Company s common stock, shares into which the 5.75% Convertible Notes were converted, shares into which the 3.50% Convertible Notes are convertible, and unvested RSUs. The shares underlying the grants of RSUs are included in the diluted earnings per share calculation beginning with grant date of the RSUs regardless of whether the shares are vested or unvested. Following the lapse of the restriction periods, the shares underlying the units will be issued and therefore will be included in the number of issued and outstanding shares.

Note 4 Earnings per Share

The dilutive effect of stock options and unvested RSUs is considered in the detailed calculations below. There were no anti-dilutive securities related to stock options or RSUs for the three-month or six-month periods ended June 30, 2006. The 3.50% Convertible Notes issued April 4, 2007 were anti-dilutive for the entire time they were outstanding during the three-month period ended June 30, 2007 and did not impact the diluted earnings per share calculation. There were no other anti-dilutive securities for the three-month or six-month periods ended June 30, 2007.

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

	For the Three Months Ended June 30,		**For the Six Months Ended June 30,**	
	2007	**2006**	**2007**	**2006**
	(In thousands, except per share amounts)			
Net income	$ 59,235	$ 40,080	$ 99,185	$ 90,606
Adjustments to net income for dilution:				
Add: interest expense not incurred if 5.75% Convertible Notes converted		1,579	1,284	3,142
Less: other adjustments		(15)	(13)	(31)
Less: income tax effect of adjustment items		(585)	(472)	(1,157)
Net income adjusted for the effect of dilution	$ 59,235	$ 41,059	$ 99,984	$ 92,560
Basic weighted-average common shares outstanding	63,583	57,082	60,316	57,157
Add: dilutive effect of stock options and unvested restricted stock units	1,537	2,176	1,559	2,296
Add: dilutive effect of 5.75% Convertible Notes using if-converted method		7,692	3,140	7,692
Diluted weighted-average common shares outstanding	65,120	66,950	65,015	67,145
Basic earnings per common share	$ 0.93	$ 0.70	$ 1.64	$ 1.59
Diluted earnings per common share	$ 0.91	$ 0.61	$ 1.54	$ 1.38

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 accrues cash bonus expense related to the current year s performance. Included in the general and administrative and exploration line items in the consolidated statements of operations are $1.2 million of cash bonus expense related to the specific performance year for each of the three-month periods ended June 30, 2007, and 2006, respectively, and $2.5 million and $2.3 million for the six-month periods ended June 30, 2007, and 2006, respectively.

Equity Incentive Compensation Plan

There are several components to the equity incentive compensation plan that are described in this section. Various types of equity awards have been granted by the Company in different periods. This section addresses the disclosure requirements for all equity awards still outstanding.

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Effective January 1, 2006, the Company adopted SFAS No. 123(R), Share Based Payment (SFAS No.123(R)) using the modified-prospective transition method. Under that transition method, compensation expense that must be recognized in periods subsequent to January 1, 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. 123(R).

As of June 30, 2007, 2.5 million shares of common stock remained available for grant under the Company s 2006 Equity Incentive Compensation Plan (the 2006 Equity 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 Equity Plan. Each stock option and similar instrument granted counts as one share against the eligible shares authorized to be issued under the 2006 Equity Plan.

The following sections describe the details of RSUs and stock options outstanding as of June 30, 2007.

Restricted Stock Incentive Program Under the 2006 Equity Incentive Compensation Plan

The Company has a long-term incentive program whereby grants of restricted stock or 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. For employees, these grants are determined annually based on a performance formula consistent with the cash bonus plan.

St. Mary issued –––78,657 RSUs on February 28, 2007, related to 2006 performance and 484,351 RSUs on February 28, 2006, related to 2005 performance. The total fair value associated with these issuances was $2.5 million in 2007 and $16.4 million in 2006 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. Accordingly, the Company recorded expense in 2005 related to the awards issued in 2006, recorded expense in 2006 related to the awards issued in 2007, and is recording expense over the earning determination period in 2007 for grants that will be issued in 2008. Vested shares of common stock underlying the RSU grants will be issued on the third anniversary of the grants, at which time the shares carry no further restrictions. For all grants made subsequent to and including the 2006 grant period, the Company is using the accelerated amortization method as described in FASB Interpretation No. 28, Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans an interpretation of APB Opinions No. 15 and 25, whereby approximately 47 percent of the total estimated compensation expense is recognized in the first year of the vesting period. Expense for grants made for plan years prior to 2006 is being amortized under the straight-line method since this method was allowed prior to the adoption of SFAS No. 123(R).

St. Mary also issued 7,575 RSUs for various grants to specific employees during the six months ended June 30, 2007. These grants have various vesting schedules. The fair value of these awards will be recorded to compensation expense over the various vesting periods.

On June 30, 2007, the Company converted 427,059 RSUs into common stock. The Company and many of the grant participants mutually agreed to net share settle the awards for the effect of income and payroll tax withholdings as provided for in the plan document and award agreements. As a result, the Company issued 302,370 shares of common stock. The remaining 124,689 shares were withheld to offset tax withholding obligations that occured upon the delivery of the shares underlying those RSUs.

As of June 30, 2007, there was a total of 684,856 RSUs outstanding, of which 386,367 were vested. Total compensation expense related to the RSUs for the three-month periods ended June 30, 2007, and 2006, was $2.4 million and $2.7 million respectively, and the total compensation expense related to the RSUs for the six-month periods ended June 30, 2007, and 2006, was $5.0 million and $5.3 million respectively. There is $1.9 million included in compensation expense for the six-month period ended June 30, 2007 for vesting of the estimated value of grants expected to be issued in 2008 related to the 2007 performance year. As of June 30, 2007, there was $6.4 million of total unrecognized compensation expense related to unvested restricted stock unit awards. The unrecognized compensation expense is being amortized through 2010.

In measuring compensation expense from the grant of RSUs, SFAS No. 123(R) requires companies to estimate the fair value of the award on the grant date. The fair value of the RSUs is inherently less than the market value of an unrestricted security. The fair value of RSUs has been measured using the Black-Scholes option pricing model. The Company s computation of expected volatility is based on the historic volatility of St. Mary s common stock. The Company s computation of expected life is 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 is 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, 2007		**2006**	
Risk free interest rate:		4.6%		4.7%
Dividend yield:	0.3	%	0.2	%
Volatility factor of the market price of the Company s common stock:	33.0	%	36.6	%
Expected life of the awards (in years):	3		3	

A summary of the status and activity of non-vested RSUs for the six-month period ended June 30, 2007, is presented below.

	Non-Vested RSUs	**Weighted-Average Grant-Date Fair Value**
Non-vested, at December 31, 2006	506,161	$ 28.92
Granted	86,232	$ 32.20
Vested	(259,611)	$ 25.86
Forfeited	(34,293)	$ 31.39
Non-vested, at June 30, 2007	298,489	$ 32.24

Stock Option Grants Under the 2006 Equity Incentive Compensation Plan

The Company previously granted stock options under the St. Mary Land & Exploration Company Stock Option Plan and Incentive Stock Option Plan. The last issuance of stock options was December 31, 2004. Stock options to purchase shares of the Company s common stock had been issued

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to eligible employees and members of the Board of Directors. All options granted to date under the option plans were granted at exercise prices equal to the respective closing market price of the Company s common stock on the grant dates, which generally occurred on the last day of a fiscal period. 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 three-month periods ended June 30, 2007, and 2006, the Company recognized stock-based compensation expense of approximately $162,000 and $518,000, respectively, related to stock options that were outstanding as of January 1, 2006. During the six-month periods ended June 30, 2007, and 2006, the Company recognized stock-based compensation expense of approximately $383,000 and $1.0 million, respectively, related to stock options that were outstanding as of January 1, 2006. There was no cumulative effect adjustment from the adoption of SFAS No. 123(R).

The following table summarizes the stock options outstanding as of June 30, 2007:

	Options	**Weighted-Average Exercise Price**	**Weighted-Average Remaining Contractual Term (In years)**	**Aggregate Intrinsic Value (In thousands)**
Outstanding, beginning of period	3,121,602	$ 12.56		
Exercised	(385,948)	$ 12.75		
Forfeited	(2,452)	$ 7.34		
Outstanding, end of period	2,733,202	$ 12.54	4.83	$ 65,828
Vested, or expected to vest, end of period	2,733,202			$ 65,828
Exercisable, end of period	2,711,044	$ 12.49	4.81	$ 65,419

As of June 30, 2007, there was $78,000 of total unrecognized compensation cost related to unvested stock option awards.

The fair value of options and Employee Stock Purchase Plan (ESPP) grants was measured at the date of grant using the Black-Scholes option pricing model. For the ESPP offering period during 2007, the Company has expensed $129,000 based on the estimated fair value on the respective grant date.

Net Profits Plan

Under the Company s Net Profits Interest Bonus Plan (the Net Profits Plan), all 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 payments under the Net Profits Plan 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 are 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 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 on each of the following two anniversary dates. Beginning with the 2006 pool, the maximum benefit to full participants from a single year s pool will be limited to 300 percent of a participating individual s adjusted base salary paid during the year to which the pool relates.

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 oil and natural gas price and cost assumptions and discount rates used in the calculations. The commodity price assumptions are formulated by applying a price that is derived from a rolling 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 adjusted to include the effect of hedge prices for the percentage of forecasted production hedged in the relevant period. The forecasted non-cash expense associated with this significant management estimate is highly volatile from period to period due primarily to fluctuations that occur in the oil and natural gas commodity markets. The Company continually evaluates the assumptions used in this calculation in order to include the current market environment for oil and natural gas prices, costs, discount rates, and overall market conditions.

The following table presents the changes in the estimated future liability attributable to the Net Profits Plan. Reductions in the liability relate to the realized results for the periods presented from oil and gas operations for the properties associated with the respective pools that have achieved payout status.

	For the Three Months Ended June 30,		**For the Six Months Ended June 30,**	
	2007	**2006**	**2007**	**2006**
	(In thousands)		**(In thousands)**	
Liability balance for Net Profits Plan as of the beginning of the period	$ 165,548	$ 143,845	$ 160,583	$ 136,824
Increase in liability	6,652	20,992	17,523	34,894
Reduction in liability for cash payments made or accrued and recognized as compensation expense	(7,812)	(6,933)	(13,718)	(13,814)
Liability balance for Net Profits Plan as of the end of the period	$ 164,388	$ 157,904	$ 164,388	$ 157,904

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 used in the calculation changed by five percent, the liability recorded at June 30, 2007, would differ by approximately $16 million. A one percentage point change in the discount rate would result in a change of the liability 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 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 a non-cash expense or benefit in the current period. The amount recorded as an expense or benefit associated with the change in the estimated liability is not allocated to general and administrative expense or exploration expense because it 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, 2007	2006	For the Six Months Ended June 30, 2007	2006
	(In thousands)		(In thousands)	
General and administrative expense	$ (540)	$ 5,768	$ 1,884	$ 8,964
Exploration expense	(620)	8,291	1,921	12,116
Total	$ (1,160)	$ 14,059	$ 3,805	$ 21,080

Note 6 Income Taxes

Income tax expense for the three-month and six-month periods ended June 30, 2007, and 2006, differs from the amount 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, and other permanent differences.

	For the Three Months Ended June 30, 2007	2006	For the Six Months Ended June 30, 2007	2006
	(In thousands)		(In thousands)	
Current portion of income tax expense:				
Federal	$ 3,200	$ 3,389	$ 4,982	$ 18,140
State	732	(247)	1,325	778
Deferred portion of income tax expense:	31,220	20,854	52,457	34,683
Total income tax expense	$ 35,152	$ 23,996	$ 58,764	$ 53,601
Effective tax rates	37.3 %	37.4 %	37.2 %	37.2 %

A change in tax rates between reported periods will generally reflect differences in the Company s estimated highest marginal state tax rates due to changes in the composition of income between state tax jurisdictions. Differences can also reflect various effects of the Company s estimates of the domestic production activities deduction, percentage depletion, and the possible impact of permanent differences related to state income tax calculations.

The Company adopted the provisions of FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes, on January 1, 2007. There was no financial statement adjustment required as a result of adoption. At adoption the Company had a long-term liability for unrecognized tax benefit of $1.0 million and accumulated interest liability of $92,000. The entire amount of unrecognized tax benefit would affect the Company s effective tax rate if recognized. Interest expense associated with income tax is recorded as interest expense in the consolidated statements of operations. Penalties associated with income tax are recorded in general and administrative expense in the consolidated statements of operations.

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction and in various states. With few exceptions, the Company is no longer subject to U.S. federal or state income tax examinations by these tax authorities for years before and including 2003. The Internal Revenue Service completed an audit for the 2000, 2002 and 2003 tax years during the quarter ended March 31, 2007. There was no change to the provision for income tax as a result of these examinations.

The Company is awaiting receipt of approximately $3.8 million for income tax refunds resulting from the carry back of net operating losses and a carry over of minimum tax credits as well as accrued interest income. The entire $3.8 million receivable has been recognized by the Company.

Note 7 Long-term Debt

Revolving Credit Facility

The Company s revolving 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 is currently $1.1 billion 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 $500 million under the credit facility. The Company must comply with certain financial and non-financial covenants. Interest and commitment fees are accrued based on the borrowing base utilization percentage table below. Euro-dollar loans accrue interest at LIBOR plus the applicable margin from the utilization table, and Alternative Base Rate (ABR) loans accrue interest at Prime plus the applicable margin from the utilization table. Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the consolidated statements of operations.

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

The Company had $96.0 million of Euro-dollar loans outstanding as of June 30, 2007.

5.75% Senior Convertible Notes Due 2022

The Company called for redemption of its 5.75% Convertible Notes on March 16, 2007. The call for redemption resulted in the note holders electing to convert the notes to common stock in accordance with the conversion provision in the original indenture. The 5.75% Convertible Note holders converted all $100.0 million of 5.75% Convertible Notes to common shares at a conversion price of $13.00 per share. The Company issued 7.7 million common shares in connection with the conversion.

3.50% Senior Convertible Notes Due 2027

On April 4, 2007, the Company issued $287.5 million aggregate principal amount of 3.50% Convertible Notes. The 3.50% Convertible Notes mature on April 1, 2027, unless earlier converted, redeemed, or purchased by the Company. The 3.50% Convertible Notes are unsecured senior obligations and rank equal in right of payment with all of the Company s existing and any future unsecured senior debt and senior in right of payment to any future subordinated debt.

Holders may convert their notes based on a conversion rate of 18.3757 shares of the Company s common stock per $1,000 principal amount of the 3.50% Convertible Notes (which is equal to an initial conversion price of approximately $54.42 per share), subject to adjustment, contingent upon and only under the following circumstances: (1) if the closing price of the Company s common stock reaches or the trading price of the notes falls below specified thresholds, (2) if the notes are called for redemption, (3) if specified distributions to holders of the Company s common stock are made or specified corporate transactions occur, (4) if a fundamental change occurs, or (5) during the ten trading days prior to, but excluding, the maturity date. The notes and underlying shares have been registered under a shelf registration statement. If the Company becomes involved in a material transaction or corporate development, it may suspend trading of the 3.50% Convertible Notes under the prospectus. In the event the suspension period exceeds 45 days within any three-month period or 90 days within any twelve-month period, the Company will be required to pay additional interest to all holders of the 3.50% Convertible Notes, not to exceed a rate per annum of 0.50% of the issue price of the 3.50% Convertible Notes; provided that no such additional interest shall accrue after April 4, 2009.

Upon conversion of the 3.50% Convertible Notes, holders will receive cash or common stock, or any combination thereof as elected by the Company. At any time prior to the maturity date of the notes, the Company has the option to unilaterally and irrevocably elect to settle its obligations upon conversion of the notes in cash and, if applicable, shares of common stock. If the Company makes this election, then, for each $1,000 principal amount of notes converted, the Company will pay the following to holders in lieu of shares of common stock: (1) an amount in cash equal to the lesser of (i) $1,000 or (ii) the conversion value determined in the manner set forth in the indenture for the 3.50% Convertible Notes, and (2) if the conversion value exceeds $1,000, the Company will also deliver, at its election, cash or common stock or a combination of cash and common stock with respect to the remaining value deliverable upon conversion. Currently, it is the Company s intention to net share settle the 3.50% Convertible Notes. However, the Company has not made this a formal legal irrevocable election and thereby reserves the right to settle the 3.50% Convertible Notes in any manner allowed under the offering memorandum as business conditions warrant.

If a holder elects to convert its notes in connection with certain events that constitute a change of control before April 1, 2012, the Company will pay, to the extent described in the related indenture, a make-whole premium by increasing the conversion rate applicable to such 3.50% Convertible Notes. In addition, the Company will pay contingent interest in cash, commencing with any six-month period beginning on or after April 1, 2012, if the average trading price of a note for the five trading days ending on the third trading day immediately preceding the first day of the relevant six-month period equals 120 percent or more of the principal amount of the 3.50% Convertible Notes.

On or after April 6, 2012, the Company may redeem for cash all or a portion of the 3.50% Convertible Notes at a redemption price equal to 100 percent of the principal amount of the notes to be redeemed plus accrued and unpaid interest, if any, up to but excluding, the applicable redemption date. Holders of the 3.50% Convertible Notes may require the Company to purchase all or a portion of their notes on each of April 1, 2012, April 1, 2017, and April 1, 2022, at a purchase price equal to 100% of the principal amount of the notes to be repurchased plus accrued and unpaid interest, if any, up to but excluding, the applicable purchase date. On April 1, 2012, the Company may pay the purchase price in cash, in shares of common stock, or in any combination of cash and common stock. On April 1, 2017 and April 1, 2022, the Company must pay the purchase price in cash.

In July 2007, the Financial Accounting Standards Board (FASB) approved the preparation of a proposed FASB Staff Position (FSP) on the accounting treatment for certain convertible debt instruments that may be settled in cash, shares of common stock, or any portion thereof at the election of the issuing company. The FSP proposes that these instruments be accounted for utilizing a bifurcation model under which the value of the debt instrument would be determined without regard to the conversion feature. The difference between this calculated value and the convertible debt instrument issue price would be allocated to the option and recorded as equity as opposed to debt. Pending enactment, the changes are proposed to become effective for years beginning after December 15, 2007. The FSP does not contain a grandfather provision, thus the Company would be required to account for its existing convertible debt instruments using the proscribed bifurcation method under the framework described by the FASB.

Weighted-average Interest Rate Paid

The weighted-average interest rates paid for the second quarters of 2007 and 2006 were 5.6 percent and 8.1 percent, respectively, including commitment fees paid on the unused portion of the credit facility aggregate commitment, amortization of deferred financing costs, amortization of the contingent interest embedded derivative associated with the 5.75% Convertible Notes, and the effects of interest rate swaps. The weighted-average interest rates paid for the six-month periods ended June 30, 2007 and 2006, were 6.3 percent and 8.2 percent, respectively. Capitalized interest costs for the Company for the three-month periods ended June 30, 2007, and 2006 were $1.2 million and $704,000, respectively, and capitalized interest costs for the six-month periods ended June 30, 2007, and 2006, were $2.6 million and $1.4 million, respectively.

Note 8 Derivative Financial Instruments

Oil and Gas Commodity Hedges

To mitigate a portion of the potential exposure to adverse market changes in oil and natural gas prices, the Company has entered into various derivative contracts. The Company s derivative contracts in place include swap and collar arrangements for the sale of oil, natural gas, and natural gas liquids. Please refer to the tables under *Summary of Oil and Gas Production Hedges in Place* in Part I, Item 2 of 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, 2007, the Company has hedge contracts in place through 2011 for a total of approximately 13 million Bbls of crude oil, 70 million MMBtu of natural gas, and 829,000 Bbls of natural gas liquids of anticipated production.

The Company attempts to qualify its oil and natural gas derivative instruments as cash flow hedges for accounting purposes. The Company formally documents all relationships between the derivative instruments and the hedged production, as well as the Company s risk management objective and strategy for the particular derivative contracts. This process includes linking all derivatives that are designated as cash flow hedges to the specific forecasted sale of oil or natural gas at its physical location. The Company also formally assesses (both at the derivative s inception and on an ongoing basis) whether the derivatives being utilized have been highly effective at offsetting changes in the cash flows of hedged production and whether those derivatives may be expected to remain highly effective in future periods. If it is determined that a derivative has ceased to be highly effective as a hedge, the Company will discontinue hedge accounting prospectively for that derivative instrument. If hedge accounting is discontinued and the derivative remains outstanding, the Company will recognize all subsequent changes in its fair value in the consolidated statement of operations for the period in which the change occurs. As of June 30, 2007, all oil, natural gas, and natural gas liquid derivative instruments qualified as cash flow hedges for accounting purposes. 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 fair value of derivative instruments is included in the balance sheets as an asset or liability. The estimated fair value of oil and natural gas derivative contracts designated and qualifying as cash flow hedges under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, was a net liability of $85.8 million at June 30, 2007.

Gains or losses from the settlement of oil and gas derivative contracts are reported in the total operating revenues section in 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

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is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in derivative loss in the consolidated statements of operations.

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

Derivative loss for the three months ended June 30, 2007, and 2006, includes a net loss of $1.2 million and $4.9 million, respectively, from ineffectiveness related to oil and natural gas derivative contracts. Amounts for the six-month periods ended June 30, 2007, and 2006, were net losses of $5.2 million and $5.8 million, respectively.

As of June 30, 2007, the estimated amount of unrealized derivative loss net of deferred income taxes to be reclassified from accumulated other comprehensive income to realized oil and gas hedge gain in the next twelve months is $5.1 million.

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

	For the Three Months Ended June 30, 2007 (In thousands)	**2006**	**For the Six Months Ended June 30, 2007 (In thousands)**	**2006**
Derivative contract settlements realized in oil and gas hedge gain	$ 7,303	$ 4,875	$ 25,987	$ 9,980
Ineffective portion of hedges qualifying for hedge accounting included in derivative loss	(1,200)	(4,918)	(5,225)	(5,754)
Non-qualified derivative contracts included in derivative gain (loss)		127	121	493
Interest rate derivative contract settlements included in interest expense			(283)	(275)
Total gain	$ 6,103	$ 84	$ 20,600	$ 4,444

Convertible Note Derivative Instrument

The contingent interest provision of the 5.75% Convertible Notes was considered an embedded equity-related derivative that was not clearly and closely related to the fair value of an equity interest and therefore was separately accounted for as a derivative instrument. There was no derivative gain or loss recorded in the consolidated statements of operations for the three-month and six-month periods ended June 30, 2007, and there was a net loss of $4,000 recorded for the three-month period ended June 30, 2006, and a net gain of $231,000 recorded for the six-month period ended June 30, 2006, from mark-to-market adjustments for this derivative. The contingent interest provision of the 3.50% Convertible Notes is also a derivative instrument. However, the value of the derivative was determined to be de minimis at the inception of the instrument.

Note 9 Pension Benefits

The Company has 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 for Both Plans

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,	
	2007	2006	2007	2006
	(In thousands)		(In thousands)	
Service cost	$ 477	$ 421	$ 955	$ 842
Interest cost	199	163	397	326
Expected return on plan assets	(135)	(107)	(270)	(190)
Amortization of net actuarial loss	54	74	109	148
Net periodic benefit cost	$ 595	$ 551	$ 1,191	$ 1,126

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

Contributions

The Company contributed $1.3 million to the Qualified Pension Plan during the second quarter of 2007. No further contributions to the Qualified Pension Plan are planned for the remainder of 2007.

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 expense in connection with the accretion of 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 statements 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, 2007 (In thousands)	2006	For the Six Months Ended June 30, 2007 (In thousands)	2006
Beginning asset retirement obligation	$ 86,519	$ 67,196	$ 77,242	$ 66,078
Liabilities incurred	3,147	1,203	4,741	1,758
Liabilities settled	(510)	(573)	(1,298)	(1,162)
Accretion expense	1,398	1,185	2,750	2,337
Revision to estimated cash flow			7,119	
Ending asset retirement obligation	$ 90,554	$ 69,011	$ 90,554	$ 69,011

Accounts payable and accrued expenses as of June 30, 2007, contain $9.3 million related to the Company s asset retirement obligation liability. Accounts payable and accrued expenses did not contain an amount related to the Company s asset retirement obligation liability as of December 31, 2006. The amount relates to the estimated plugging and abandonment costs associated with one off-shore platform that was destroyed during Hurricane Rita. Plugging and abandonment of the platform is expected to be completed by the end of 2007.

Note 11 Repurchase of Common Stock

Stock Repurchase Program

The Company has an ongoing share repurchase program. As of the date of this filing, the Company has Board authorization to repurchase up to 6 million shares of common stock. The shares may be repurchased from time to time in open market transactions or in 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.

During the second quarter of 2006 St. Mary repurchased 3,319,300 shares of its common stock at a weighted average price of $37.09 per share including commissions. St. Mary did not repurchase any shares of common stock under the program during the six month period ended June 30, 2007.

Note 12 Insurance Settlement

In April of 2007 the Company reached a global insurance settlement for reimbursement of damages sustained during Hurricane Rita. St. Mary s net amount of the final settlement is approximately $33 million. As a result of this settlement, the Company recorded a gain, included in other revenue in the accompanying financial statements, of $6.3 million during the second quarter of 2007. The gain calculation takes into consideration approximately $9.3 million of future costs associated with the plugging and abandonment of one offshore platform. Additionally, the Company has accrued for approximately $1.3 million of expected hurricane related damage repair costs related to its non-operated properties. The Company continues to closely monitor the activities associated with these properties. Any significant variation between actual and estimated plugging and abandonment and non-operated damage repair costs will impact the final determination of the gain associated with the insurance settlement. The Company expects adjustments to the gain to be completed by the fourth quarter of 2007.

Note 13 Subsequent Events

On August 2, 2007, the Company signed a Purchase and Sale Agreement to acquire oil and gas properties located primarily in Webb County, Texas. The purchase price for these assets is $153.1 million and the transaction is scheduled to close in the first half of October 2007. The properties target gas production in the Olmos formation. This acquisition is adjacent to the recently acquired Catarina Field assets discussed in Note 3 - Acquisitions. It is expected that the Company will pay for this acquisition with available cash flows and its existing revolving credit facility. The Company has hedged the first three years of natural gas production and the first year of associated liquids.

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

This discussion contains forward-looking statements. Please refer to Cautionary Information 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, natural gas liquids, 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 carbonate formations of East Texas and North Louisiana; South Texas assets targeting the Olmos formation; and the onshore Gulf Coast and offshore Gulf of Mexico.

Our primary objective is growing net asset value per share. Over the long term we believe that growing net asset value per share leads to superior stock price performance. A focus on net asset value per share provides us the flexibility to pursue a variety of projects that we believe will create value but requires us to be disciplined in our investment decisions. We believe that our regional diversity and the balance between oil and natural gas in our proved reserves are advantages which we can leverage to build value for our stockholders.

Oil and Gas Production and Operating Margins

Our production for the second quarter of 2007 was 26.0 BCFE. This is the sixth consecutive quarter of increasing production. Production increases are a reflection of our continuing drilling operations and the acquisition of oil and gas assets in the Permian that was completed in December 2006. Growth from quarter to quarter is impacted by such factors as the timing of drilling operations, completions, well workovers and other operational issues. We believe that a key metric for measuring success of oil and gas production companies is the ability to grow reserves on an economic basis, providing a base for growth in production.

Our operating margins, net of general and administrative costs, remain very strong in large part because 39 percent of our production was crude oil production during the second quarter of 2007. Strong crude oil prices and solid realizations from our hedging program contributed to a net equivalent operating margin of $6.12 per MCFE on our existing production. This represents a seven percent increase from the same period a year ago.

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. We sell the majority of our natural gas on contracts which use first of the month index pricing, which means gas produced in that month is sold at the first of the month price regardless of the spot price on the day the gas is produced. Our crude oil is sold using contracts that pay us the average of the posted prices for the period in which the crude oil is produced.

The three-month average bid week price for natural gas at Henry Hub increased 10 percent to $7.56 per Mcf between the first quarter and second quarter of 2007. This was 11 percent higher than the same period in 2006, when prices were held in check by high levels of natural gas in storage. Pricing differentials between Henry Hub and various regional natural gas hubs where we market our gas were reasonably stable during the second quarter of 2007 with the exception of hubs in the Rocky Mountain region. Various Rocky Mountain pricing points have experienced exceptionally high differentials during 2007 that have impacted our revenue from natural gas in this area. Rocky Mountain gas comprises approximately 17 percent of our natural gas volumes and 10 percent of our total equivalent volumes on a company-wide basis. A major pipeline project, Rockies Express, in the Rocky Mountain region is expected to come online in early 2008. The differentials implied by the futures curves between Rocky Mountain hubs and Henry Hub indicate that the pressure on prices in the Rocky Mountains should moderate when Rockies Express is placed in service. Looking ahead, the futures market for natural gas continues to appear strong, with the NYMEX first, second, and third year contracts trading at $7.86, $8.50, and $8.39, respectively, on an MMBtu basis as of the end of the quarter. Subsequent to quarter-end, natural gas prices have been pressured downward due to bearish market sentiments related to high levels of natural gas in storage, lack of hurricane activity thus far this year, and mild summer weather throughout large portions of the country.

The average spot NYMEX price for West Texas Intermediate (WTI) crude for the second quarter of 2007 was $65.03 per barrel, which represents a 12 percent increase from the first quarter of 2007. Crude oil prices were supported at high levels throughout the quarter due to an attempted terrorist strike in Saudi Arabia, concerns regarding violence in Nigeria, and general unrest in various oil producing regions of the world. Domestically, concerns over refinery utilization and petroleum product inventories also pressed crude prices higher. Approximately 70 percent of our crude oil production comes from our properties in the Rocky Mountain region, where differentials continued to improve. Strong prices realized on our crude are primarily the result of refinery requirements to secure feedstock in anticipation of demand for refined products during the summer driving season. For the first several weeks of July 2007, spot WTI prices closed above $70 per barrel. Looking forward, the futures market for crude oil also appears strong, with the NYMEX first, second, and third year contracts trading at $70.43, $71.19, and $70.69, respectively, on a per barrel basis as of the end of the quarter.

While changes in quoted NYMEX oil and Henry Hub natural gas prices are generally used as a basis for comparison within our industry, the price we receive for oil and natural gas is affected by quality, energy content, and transportation differentials for these products. We refer to this price as our realized price, which excludes the effects of hedging. Our realized price is further impacted by the result of our hedging contracts that have settled in the respective periods, which is referred to as our net realized price. Our natural gas price realizations for the three months ended June 30, 2007, were improved by $9.2 million of realized hedging gains while our oil price realization was negatively impacted by $1.9 million of realized hedging losses. For the six months ended June 30, 2007, our natural gas price realizations were improved by $27.9 million of realized hedging gains and our oil price realization was negatively impacted by $1.9 million of realized hedging losses.

		For the Three Months Ended June 30, 2007
Crude Oil (per Bbl):		
NYMEX price	$	65.03
Net realized price	$	61.11
Net realized price, including the effects of hedging	$	59.97
Natural Gas (per Mcf):		
NYMEX price	$	7.56
Net realized price	$	7.09
Net realized price, including the effects of hedging	$	7.68

Hedging Activities

We have an active hedging program, which is largely built around acquisitions. We hedge the first two to five years of an acquisition s risked production. We occasionally enter into derivative transactions to hedge a portion of our existing forecasted production. In October 2005 we hedged a significant portion of anticipated future production from our current producing properties using zero-cost collars. We also hedged a portion of specific forecasted natural gas production for 2006, 2007, and 2008, using swap contracts. Taking into account all oil and gas production hedge contracts in place through July 31, 2007, we have hedged anticipated production of approximately 14 million Bbls of oil, 83 million MMBtu of natural gas, and 1 million Bbls of natural gas liquids through the year 2011. We believe we have established an economic base for our future operations, and the floors and ceilings on our collars minimize our exposure to price declines while also allowing us to participate in a higher oil and natural gas price environment. 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.

Cost Environment

After several years of cost escalation, we have begun to see cost reductions for some services associated with drilling operations. In general, day rates for land-based drilling rigs are moderating and in some cases are decreasing as drillers face an increased supply of drilling rigs available for hire. With availability of drillers increasing, we believe there is potential to further reduce costs by working with more efficient service providers. Prices for completion services continue to be firm, as new supply in this segment of the industry has been slower to build. However, the cost environment remains highly dynamic and varies greatly from region to region. Historically, cost changes have lagged commodity prices, both on upward and downward price trends. In making our investment decisions, we evaluate current economics on an individual investment basis prior to proceeding. We have a formal process for establishing a drilling budget and 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 date of this filing, our drilling budget for 2007 is estimated to be $727 million, plus approximately $190 million of acquisitions, as discussed below.

We continue to see pressure related to our oil and gas production operating costs. Oil properties are generally more labor intensive. Our well servicing vendors are experiencing the same personnel constraints and compensation inflation as other segments of the petroleum industry. Costs associated with the operation of workover rigs, fuel surcharges for trucking, and disposal of saltwater are a few areas of our business where we are seeing cost pressure.

As a result of the growth in our drilling inventory, we have initiated a review of our purchasing practices with the intention of consolidating our purchasing efforts to realize savings through volume discounts offered by vendors as well as to secure a supply of critical materials. We believe that this initiative will have a positive impact on our cost structure over the next several years.

Net Profits Plan

Payments made for distributions from the Net Profits Plan have been expensed as compensation costs in the amount of $7.8 million and $13.7 million for the three-month and six-month periods ended June 30, 2007. These 2007 payments are lower than originally budgeted due to the effects of increased oil and gas production expense and additional capital expenditures, which decreased the current impact of, and delayed the timing of payout for, a specific 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* sections below. While we have adjusted our forecast to approximately $33 million of cash payments to be made in 2007, it is not possible to predict this with certainty due to the impact of commodity prices and reserve estimates on the valuation of this estimated liability.

With respect to the accounting estimate of the liability associated with future estimated payments from our Net Profits Plan, we have recorded $3.8 million of net expense for the six-month period ended June 30, 2007. We note the liability has decreased $1.2 million from March 31, 2007. This decrease is due to an increase in the effects of increasing oil and gas production expense, primarily in the Rockies.

The calculation of the estimated liability associated with the Net Profits Plan requires management to prepare an estimate of future amounts payable from the 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 principal factors for our estimates are forecasted oil and gas production from the properties that comprise each individual pool, price assumptions, cost assumptions, and the 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 both before and 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 commodity price realizations and anticipated hedge prices for the percentage of forecasted hedged production 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 five percent, the liability recorded on the balance sheet at June 30, 2007, would differ by approximately $16 million. A one percentage point change in the discount rate would result in a change to the liability of approximately $8 million. We frequently re-evaluate the assumptions used in our calculations and consider the possible impacts stemming from the current market environment including current and future oil and gas prices, discount rates, and overall market conditions.

Events Subsequent to June 30, 2007

On August 2, 2007, we signed a purchase and sale agreement for the acquisition of $153.1 million of oil and gas properties located primarily in Webb County, Texas. The properties are predominantly natural gas and associated liquids targeting the Olmos formation. This acquisition is adjacent to our recently acquired Catarina acreage. We believe this second acquisition solidifies a meaningful asset position with significant development potential. We have estimated proved reserves associated with this acquisition of approximately 95 BCFE. The acquisition is expected to close in the first half of October 2007. We anticipate funding this acquisition with available cash flows and our existing revolving credit facility. We have hedged the first three years of gas production and the first year of associated liquids.

Second Quarter 2007 Highlights

In April 2007 we completed the private placement of $287.5 million of 3.50% Convertible Notes. The net proceeds from the 3.50% Convertible Notes were used to repay outstanding borrowings under our revolving credit facility. The borrowing base associated with our revolving credit facility was also increased to $1.1 billion and we have continued to elect the $500 million commitment amount provided by the facility. Our immediately available borrowing capacity as of June 30, 2007, is $403 million. Please see Note 7 Long-term Debt in Part I, Item 1 of this report for a description of the terms of our 3.50% Convertible Notes.

Additionally, in April of 2007, we received the final payment of our $33 million global insurance settlement for reimbursement of damages sustained during Hurricane Rita in 2005, resulting in a gain of $6.3 million which has been recorded as other revenue in the accompanying financial statements. Please see Note 12 Insurance Settlement in Part I, Item 1 of this report for additional information regarding the settlement.

In June 2007 we closed on the acquisition of assets in the Catarina Field in South Texas. The Catarina Field produces natural gas from the Olmos formation. The acquisition price was $29.5 million, before normal purchase price closing adjustments. This represents an addition of approximately 14.0 BCFE of proved reserves and will contribute approximately 0.6 BCFE of production in 2007.

We have announced a number of organizational and managerial changes recently. In June 2007 we announced the realignment of our Greater Gulf Coast region resulting in the separate management of the Gulf Coast and Permian Basin operations. Based on the scale of each operation, we believe it was appropriate to separate the management to allow greater focus in these areas. The Gulf Coast region is based in Houston, and manages our onshore Gulf Coast properties in Texas and Louisiana, including the recently acquired Catarina Field, as well as our Gulf of Mexico assets. The Permian Basin region is based in Midland, Texas and manages our assets in southeastern New Mexico and West Texas. In conjunction with this realignment, Lehman (Newt) Newton III was appointed to the new position of Vice President Regional Manager and Greg Leyendecker was appointed as Vice President Regional Manager. Mr. Leyendecker replaced Jerry Schuyler, the former regional manager of the Greater Gulf Coast region, who resigned in the second quarter. We hired Stephen Pugh as Senior Vice President and Regional Manager. Mr. Pugh replaced David Hart, who retired from St. Mary in late July as regional manager of the ArkLaTex region. Mr. Hart had been with St. Mary since 1992.

Our second quarter 2007 net income was $59.2 million or $0.91 per diluted share compared to 2006 results of $40.1 million or $0.61 per diluted share. Production for the second quarter was 26.0 BCFE. This represents a 15 percent increase from the same period a year ago and a two percent increase from the previous quarter. Per MCFE lease operating expense and transportation expense remained static at $1.37 as compared to a year ago. Production taxes increased $0.02 to $0.56 per MCFE, and DD&A, including ARO accretion expense, increased $0.51 to $2.10 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, 2007, and the immediately preceding three quarters. Additional per MCFE detail is contained later in this section.

	For the Three Months Ended June 30, 2007	March 31, 2007	December 31, 2006	September 30, 2006
	(In millions, except production sales data)			
Production (MCFE)	26.0	25.5	25.1	23.2
Oil and gas production revenues before the effects of hedging	$ 216.2	$ 193.7	$ 180.6	$ 188.2
Lease operating expense	$ 31.6	$ 34.1	$ 31.2	$ 30.1
Transportation costs	$ 4.2	$ 4.4	$ 3.0	$ 2.4
Production taxes	$ 14.5	$ 13.7	$ 12.9	$ 12.5
General and administrative expense	$ 13.7	$ 11.1	$ 7.9	$ 9.7
Net income	$ 59.2	$ 40.0	$ 43.5	$ 55.9
<u>Percentage change from previous quarter:</u>				
Production (MCFE)	2 %	2 %	8 %	3 %
Oil and gas production revenues before the effects of hedging	12 %	7 %	(4)%	6 %
Lease operating expense	(7)%	9 %	4 %	6 %
Transportation costs	(5)%	47 %	25 %	(11)%
Production taxes	6 %	6 %	3 %	2 %
General and administrative expense	23 %	41 %	(19)%	(7)%
Net income	48 %	(8)%	(22)%	39 %

First Six Months 2007 Highlights

In the first six months of 2007 our net income was $99.2 million or $1.54 per diluted share compared to second quarter 2006 income of $90.6 million or $1.38 per diluted share. Production for the first six months was 51.5 BCFE. This represents a 16 percent increase from the same period a year ago. Per MCFE lease operating expense and transportation expense increased $0.09 to $1.45 as compared to a year ago. This increase over the last year s comparable period is due to an increase in oil and gas production expense. 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 order to restore or increase production in the Rockies associated with transactions completed in recent years. Production taxes increased $0.01 to $0.55 per MCFE, and DD&A, including ARO accretion expense, increased $0.43 to $2.01 per MCFE. We discuss these financial results and trends in more detail below.

We called our 5.75% Convertible Notes for redemption in March 2007. The note holders elected conversion of the notes into shares of common stock. As a result, we reclassified the $100.0 million of debt associated with the issuance to equity and issued 7.7 million shares of common stock. The combination of this conversion, the issuance of $287.5 million of 3.50% Convertible Notes, net income earned for the six month period ended June 30, 2007, and the change in accumulated other comprehensive income primarily associated with the change in the derivative valuation, has resulted in our debt to book capitalization ratio decreasing from 37 percent at December 31, 2006, to 30 percent at June 30, 2007.

Outlook for the Remainder of 2007

The execution of our drilling program and an intense focus on operating costs will be the principal areas of focus over the remainder of the year. We continue to be confident that we will have access to the rigs and services required to carry out our drilling program. Costs associated with drilling wells have moderated over the past year, with day rates remaining relatively flat and in some cases decreasing. Completion costs have been slower to respond, but we are no longer seeing the significant increases in these costs that were common a year ago. We believe that there are opportunities to decrease our costs by transitioning our programs over time to be more efficient with the procurement of drilling and related service providers as well as tubulars and equipment. All other factors being equal, the strong commodity price and stable-to-declining drill and complete cost environment that we are currently experiencing are expected to allow us to continue to execute the budgeted 2007 business plan we announced earlier this year. The highlights of the remaining 2007 capital program include:

- *Rockies - Conventional* Our 2007 operated property plan for the conventional Rockies program involves expanding a horizontal re-entry program in the Mississippian formations of the Williston Basin, the exploitation of Bakken infill locations in Montana, and drilling Red River projects. We plan to operate two to three rigs in the region for the remainder of the year. Non-operated activities include wells targeting the Bakken, Madison, and Mission Canyon formations in the Williston Basin, and Almond formation development wells in the eastern Green River Basin Wamsutter area in Wyoming. Due to significant natural gas price decreases in this region, a number of the projects we planned to pursue will be delayed into 2008. In contrast, oil projects continue to have solid economics given high oil prices.

- *Rockies - Hanging Woman Basin Coalbed Methane* At the end of June 2007, there were 360 wells producing 13.3 MMcf per day gross and 8.0 MMcf per day net. A sequential decrease in the production rate is the result of high summer temperatures impacting compressor facilities in one of our project areas. During two months of the quarter, the Hanging Woman Basin program area experienced an unusually high amount of rainfall which severely impacted our ability to move rigs and equipment in the field. As a result, the previously announced target of 258 total wells drilled for 2007 may be at risk. We and our operating partners will attempt to offset delays caused by the weather by increasing the number of operated rigs beginning in August.

- *Mid-Continent* Our 2007 plans in the Mid-Continent are principally centered on the Arkoma program in eastern Oklahoma and the Anadarko Basin in western Oklahoma. Two operated rigs are currently working in the Arkoma program, where we are primarily targeting the Woodford Shale formation with horizontal wells in 2007. Our drilling and completion design continues to evolve. We continue to evaluate various drilling and completion techniques to ensure the best long-term performance from this program while also pursuing cost saving technologies to improve our overall economics. At the end of the second quarter, we had four horizontal Woodford Shale wells at various stages of completion. Subsequent to quarter end, one of these wells was successfully completed using a drilling and completion design similar to that used on other proven successful wells in the play. We believe the production results from this well compare favorably to some of the better wells that have been drilled in the area. Two of the three remaining wells being completed at quarter-end also used this design. In the Anadarko Basin, we plan on operating one rig for the remainder of the year which will be focused primarily on drilling wells targeting the Granite Wash formation. At Constitution Field, the Loretta B. Casey (SM 40% WI) was completed in the second quarter in the Yegua formation. We continue to evaluate the potential for further development at Constitution Field.

- *ArkLaTex* Activity in the ArkLaTex for 2007 is focused on an operated horizontal carbonate program in the James Lime trend and two outside-operated programs. We are planning to operate two rigs in our horizontal carbonate program over the remainder of 2007, resulting in approximately 18 operated wells this year. Most of these 18 wells will target the James Lime interval. We have had two successful wells outside our traditional operating areas this year that we believe will lead to additional drilling opportunities in the trend. The two successful non-operated plays are the Elm Grove and Terryville Fields. At Elm Grove, we anticipate participating in fewer grass roots Hosston wells than we originally budgeted at the beginning of the year as a consequence of an ongoing interest equalization program in the field with an operating partner. This will allow commingling of various producing intervals in the field, the effect of which is a further improvement in the overall efficiency of field development through recompletions. At Terryville Field, we expect to participate in eight wells in 2007 versus the originally budgeted five wells.

- *Permian Basin* Our Permian Basin activity in 2007 will be significantly higher as a result of our acquisition of assets in the Sweetie Peck area in late 2006. We plan to have 54 wells drilled in Sweetie Peck during 2007. Net production for Sweetie Peck at the end of the quarter was 3.1 MBOE per day, up from 2.8 MBOE per day at the end of the first quarter of 2007 and 2.6 MBOE per day at the end of 2006. We are currently operating five rigs in the Sweetie Peck area. Additionally, we plan to participate in roughly 30 wells this year in a non-operated tight oil program which has similar geologic attributes to Sweetie Peck. Activity is also planned at HJSA and at our waterflood projects in southeastern New Mexico.

- *Gulf Coast* In this region, activity for the second half of 2007 will be centered on integrating our new acquisitions targeting natural gas in the shallow Olmos formation in South Texas. We currently have two operated drilling rigs running in Catarina Field and expect to add one rig with our more recent acquisition. Additional drilling operations resulting from this acquisition are expected to increase our 2007 drilling budget by approximately $6 million. Other activity will include participation in several recompletions at Judge Digby Field and bringing previously announced discoveries on to production. In the second quarter, the previously announced Clement #1 (SM 35% WI) was successfully completed ahead of schedule.

Our planned drilling program described above is dynamic, and there are a number of factors that could impact our decisions to invest capital in one or all of these regions. Commodity prices, well costs, and program performance are a few factors that individually or in combination could change the scale or relative allocation of our drilling and acquisition budgets.

We continue to evaluate acquisitions, both in our regional offices and at our corporate headquarters. Including the anticipated closing of the $153.1 million acquisition of the South Texas assets, we anticipate capital spending for acquisitions of approximately $190 million in 2007. We have a strong track record of making economic acquisitions. We have grown our inventory of drilling prospects in part through acquisitions and original leasehold development. Our strong balance sheet gives us the ability to move quickly when we find an acquisition target that we believe will be accretive to us. We may also divest selected non-core assets when market conditions and prices are attractive. We continuously evaluate opportunities in the marketplace for oil and gas properties and, accordingly, we may be a buyer or a seller of properties at various times.

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

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

	For the Three Months Ended June 30, 2007	For the Three Months Ended June 30, 2006	% of Change Between Periods	For the Six Months Ended June 30, 2007	For the Six Months Ended June 30, 2006	% of Change Between Periods
Net production volumes						
Oil (MBbls)	1,698	1,429	19 %	3,407	2,957	15 %
Natural gas (MMcf)	15,848	14,023	13 %	31,068	26,812	16 %
MCFE (6:1)	26,033	22,595	15 %	51,509	44,556	16 %
Average daily production						
Oil (Bbls per day)	18,655	15,698	19 %	18,823	16,339	15 %
Natural gas (Mcf per day)	174,150	154,102	13 %	171,645	148,132	16 %
MCFE per day (6:1)	286,082	248,292	15 %	284,581	246,168	16 %
Oil & gas production revenues(1)						
Oil production	101,803	85,163	20 %	191,753	168,442	14 %
Gas production	$ 121,654	$ 97,669	25 %	$ 244,094	$ 203,560	20 %
Total	$ 223,457	$ 182,832	22 %	$ 435,847	$ 372,002	17 %
Oil & gas production expense						
Lease operating expenses	$ 31,629	$ 28,292	12 %	$ 65,754	$ 54,624	20 %
Transportation costs	4,159	2,748	51 %	8,606	5,595	54 %
Production taxes	14,540	12,238	19 %	28,288	24,273	17 %
Total	$ 50,328	$ 43,278	16 %	$ 102,648	$ 84,492	21 %
Average realized sales price, before hedging						
Oil (per Bbl)	$ 61.11	$ 63.68	(4)%	$ 56.85	$ 60.22	(6)%
Natural gas (per Mcf)	$ 7.09	$ 6.20	14 %	$ 6.96	$ 6.86	1 %
Average realized sales price, net of hedging						
Oil (per Bbl)	$ 59.97	$ 59.62	1 %	$ 56.28	$ 56.96	(1)%
Natural gas (per Mcf)	$ 7.68	$ 6.96	10 %	$ 7.86	$ 7.59	4 %
Per MCFE Data:						
Average realized sales price, before hedging	$ 8.30	$ 7.88	5 %	$ 7.96	$ 8.13	(2)%
Average realized sales price, net of hedging	$ 8.58	$ 8.09	6 %	$ 8.46	$ 8.35	1 %
Lease operating expense	(1.21)	(1.25)	(3)%	(1.28)	(1.23)	4 %
Transportation	(0.16)	(0.12)	33 %	(0.17)	(0.13)	31 %
Production taxes	(0.56)	(0.54)	4 %	(0.55)	(0.54)	2 %
General and administrative	(0.53)	(0.46)	15 %	(0.48)	(0.48)	%
Operating margin	$ 6.12	$ 5.72	7 %	$ 5.98	$ 5.97	%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$ 2.10	$ 1.59	32 %	$ 2.01	$ 1.58	27 %

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

	June 30, 2007	December 31, 2006	% of Change Between Periods
Working capital (deficit)	$ (30,858)	$ 22,870	(235)%
Long-term debt	$ 383,500	$ 433,980	(12)%
Stockholders equity	$ 898,804	$ 743,374	21%

	For the Three Months Ended June 30, 2007	2006	% of Change Between Periods	For the Six Months Ended June 30, 2007	2006	% of Change Between Periods
Basic net income per common share	$ 0.93	$ 0.70	33%	$ 1.64	$ 1.59	3%
Diluted net income per common share	$ 0.91	$ 0.61	49%	$ 1.54	$ 1.38	12%
Basic weighted-average shares outstanding	63,583	57,082	11%	60,316	57,157	6%
Diluted weighted-average shares outstanding	65,120	66,950	(3)%	65,015	67,145	(3)%

We present this table as a summary of information relating to key indicators of financial condition and operating performance that we believe are important.

We present per MCFE information because we use this information to evaluate our performance relative to our internal targets as well as our peers, and to identify and measure trends that we believe require analysis. Our quarter-to-quarter comparison of financial results presented later provides additional details and analysis of changes between the quarters in selected line items. We expect oil and gas production expenses to increase slightly throughout 2007 as a result of increased production from higher cost oil projects in the Permian Basin region. Depreciation, depletion, and amortization per MCFE will continue to significantly increase due to higher costs associated with finding and acquiring crude oil and natural gas reserves. General and administrative expense is projected to decrease in the third and fourth quarters of 2007 as compared to the second quarter. The decrease is a reflection of a more normalized expense base. Variability in this expense will be most significantly affected by commodity prices that impact Net Profits Plan payments and the impact of changes to estimates of bonus compensation.

We have in-the-money stock options and unvested RSUs that are considered potentially dilutive securities. At times these dilutive securities can affect our earnings per share. Consequently, both basic and diluted earnings per share are presented in the table above. We are accounting for our 3.50% Convertible Notes under the treasury stock method. As a result, there is no impact on the diluted share calculation at the current time since the Company s stock price is not above the conversion price for the issuance. A detailed explanation is presented in Note 4 Earnings Per Share, Part I, Item 1 of this report. Basic and diluted weighted-average common shares outstanding used in our earnings per share calculations for the three-month periods ended June 30, 2007, and 2006 reflect an increase in outstanding shares related to stock option exercises. We issued 385,948 and 1,286,011 shares of common stock during the six-month periods ended June 30, 2007, and 2006, respectively, as a result of stock option exercises. Additionally, on June 30, 2007, we issued 302,370 shares of common stock as a result of converting RSUs to common stock in accordance with the terms of the RSU grants. The remaining information in the table relates to information we have provided in our 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 plan for the foreseeable future.

Sources of Cash

Based on our current forecast, we expect our total 2007 capital spending under the drilling and acquisition program to exceed our cash flow generated from operations. Accordingly, we expect to access cash funding through the use of our revolving credit facility and the issuance of long-term debt, as evidenced by the $287.5 million of 3.50% Convertible Notes. This debt issuance is more fully described in Note 7 Long-term Debt in Part I, Item 1 of this report.

Our primary sources of liquidity are the cash provided by operating activities, debt financing, sales of non-strategic properties, and cash raised through the capital markets. All of these sources can be impacted by the general condition of our industry and by significant fluctuations in oil and natural gas prices, operating costs, and volumes produced. We have no control over the market prices for oil and natural gas, although we are able to influence the amount of our net revenues related to oil and gas sales through the use of derivative contracts. A decrease in market prices for commodities would reduce expected cash flow from operating activities and could reduce the borrowing base of our credit facility as well as the value of non-strategic properties we might consider selling. Historically, decreases in market prices for commodities have limited our industry s access to the capital markets. The debt and equity capital markets are currently favorable to energy companies that operate in the exploration and production industry. This is a result of strong commodity prices and the general strength reflected in the balance sheets of the companies in our industry.

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 $1.1 billion, and we have elected a commitment amount of $500 million. We believe this commitment level is adequate for our near-term liquidity requirements. The credit agreement has a maturity date of April 7, 2010. We must comply with certain financial and non-financial covenants, and we are currently in compliance with all of those covenants. As of July 31, 2007, we had $413 million of available borrowing capacity under this facility. 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 Long-term Debt in Part I, Item 1 of this report. We have a single letter-of-credit outstanding under our facility in the amount of $1.1 million. This reduces the amount available under the commitment amount on a dollar-for-dollar basis. Borrowings under the facility are secured by mortgages on the majority of our oil and gas properties and by a pledge of the common stock of our material subsidiary companies.

Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the consolidated statements of operations. We had an outstanding loan balance of $96.0 million as of June 30, 2007, comprised entirely of Euro-dollar based borrowings.

Our weighted-average interest rate paid for the three- and six- month periods ended June 30, 2007, was 5.6 percent and 6.3 percent, respectively and included fees paid on the unused portion of the credit facility aggregate commitment amount and amortization of deferred financing costs associated with the 3.50% Convertible Notes.

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, general and administrative costs, income taxes, common stock repurchases, and stockholder dividends. In the first six months of 2007 we spent $279.0 million for capital development and $31.1 million on acquisitions. These cash outflows were funded using cash inflows from operations and available borrowing capacity under our revolving credit facility.

We have Board authorization to repurchase up to 6 million shares of our common stock under our stock repurchase program. These shares may be repurchased from time to time in open market transactions or privately negotiated transactions subject to market conditions and other factors including certain provisions of our existing bank credit facility agreement and compliance with securities laws.

On May 14, 2007, we paid $3.1 million in dividends to stockholders of record as of the close of business May 4, 2007. Our intention is to continue to make these dividend payments for the foreseeable future subject to our future earnings, our financial condition, possible credit facility covenants, and other currently unexpected factors which could arise.

The following table presents amounts and percentage changes in cash flows between the six-month periods ending June 30, 2007, and June 30, 2006. 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, 2007	2006	Change	Percent Change
		(In thousands)		
Net cash provided by operating activities	$ 282,321	$ 216,352	$ 65,969	30 %
Net cash used in investing activities	$ (302,331)	$ (186,132)	$ (116,199)	62 %
Net cash provided by (used in) financing activities	$ 44,725	$ (43,320)	$ 88,045	203 %

Analysis of cash flow changes between the six-month periods ended June 30, 2007, and June 30, 2006

Operating activities. Cash received from oil and gas sales, net of the effects of hedging, increased $119.6 million to $430.8 million for the six-month period ended June 30, 2007, from $311.2 million for the six-month period ended June 30, 2006. This increase was the result of a 16 percent increase in production volumes and a one percent increase in our net realized price after hedging, resulting in a 17 percent increase in production revenue. The benefits derived from the production and pricing were somewhat offset by an increase in oil and gas production expense.

Investing activities. Cash proceeds from the insurance settlement related to Hurricane Rita totaled $7.0 million for the six-month period ended June 30, 2007. Total cash outflow for 2007 capital expenditures for leasehold and drilling activities increased $97.4 million or 54 percent, and cash outflow related to the acquisition of oil and gas properties increased $26.3 million, or 551 percent, compared to the same period in 2006. Cash received from short-term investments classified as available-for-sale, increased $1.5 million for the six-month period ended June 30, 2007 as compared to the same period in 2006, whereas deposits paid to short-term investments available-for-sale increased $1.1 million for the six-month period ended June 30, 2007 as compared to the same period in 2006.

Financing activities. Net borrowings against our credit facility decreased $289.0 million for the six-month period ended June 30, 2007, compared with the same period in 2006. Payments against our short-term note payable increased $4.5 million for the six-month period ended June 30, 2007, compared with the same period in 2006. We received $281.2 million from the issuance of convertible debt in the second quarter of 2007. Our income tax benefit attributable to the exercise of stock options decreased $10.5 million to $3.8 million for the six months ended June 30, 2007. We received $9.5 million less from the sale of common stock in the six-month period ended June 30, 2007 compared to the same period in 2006.

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 increased slightly to $727 million, to include anticipated capital associated with our recently announced South Texas acquisition. These amounts exclude non-cash asset retirement obligation capitalized assets. Anticipated 2007 exploration and development expenditures for each of our regions are presented in the following table.

	Exploration and Development Expenditures (In millions)
Mid-Continent region	$ 206
Rocky Mountain region	146
ArkLaTex region	125
Permian Basin region	126
Gulf Coast region	66
Hanging Woman Basin CBM	58
	$ 727

The $727 million anticipated capital expenditure budget reflects slight reallocation of capital between the regions. In the Rocky Mountain region, the estimated capital spent was lowered due to the deferral of several natural gas projects. Anticipated capital expenditures decreased in the ArkLaTex region primarily as a result of our postponement of drilling Glen Rose wells while we await the results of technical evaluations in that program and our plan to drill fewer grass roots Hosston wells and to utilize a more efficient plan to access these reserves. In the Permian, forecasted capital expenditures have grown due to our increased participation in a non-operated tight oil play that is analogous to our operated Sweetie Peck program.

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. It is important to note that strong commodity prices have decreased the amount by which we forecast outspending our positive cash flows. 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, 2007	2006
	(In thousands)	
Development costs	$ 254,573	$ 147,599
Exploration costs	67,774	73,425
Acquisitions:		
Proved	31,277	16,149
Unproved	(227)	
Leasing activity	24,138	13,944
Total, including asset retirement obligation	$ 377,535	$ 251,117

Costs incurred for capital and exploration activities during the first six months of 2007 increased $126.4 million or 50 percent compared to the same period in 2006. Excluding acquisitions, our development and exploration spending has increased $101.3 million compared to the same six-month period in the prior year. A significant percentage increase in lease costs reflects a focus on gaining access to leasehold in developing oil and gas plays.

We believe 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 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 our industry.

In April 2007 we completed the private placement of $287.5 million of 3.50% Convertible Notes as discussed in Note 7 - Long-term Debt of Part I, Item 1 of this report.

Commodity Price Risk and Interest Rate Risk

We are exposed to market risk, including the effects of changes in oil and gas commodity prices and changes in interest rates as discussed below. Since we produce and sell crude oil, natural gas and natural gas liquids, 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.

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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/A for the year ended December 31, 2006.

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 acquisitions. 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.

As of July 31, 2007, our hedged positions totaled approximately 14 million Bbls of crude oil, 83 million MMBtu of natural gas, and 1 million Bbls of natural gas liquids of anticipated future production through 2011. These amounts include those volumes associated with the recently acquired South Texas acquisitions. We seek to minimize basis risk and index the majority of our oil contracts to NYMEX prices and our gas contracts to various regional index prices associated with pipelines in proximity to our areas of gas production.

The following tables describe the volumes, average contract prices, and fair value of contracts we have in place as of June 30, 2007.

Oil Contracts

Oil Swaps

Contract Period	**Volumes (Bbl)**	**Weighted-Average Contract Price (Per Bbl)**	**Fair Value at June 30, 2007 (Liability) (In thousands)**
Third quarter 2007			
NYMEX WTI	345,684	$ 60.81	(3,479)
IF Bow River	12,000	$ 39.86	(145)
Fourth quarter 2007			
NYMEX WTI	354,620	$ 61.78	(3,370)
2008			
NYMEX WTI	1,575,000	$ 68.57	(5,648)
2009			
NYMEX WTI	1,363,000	$ 67.74	(5,678)
2010			
NYMEX WTI	1,239,000	$ 66.47	(5,595)
2011			
NYMEX WTI	1,032,000	$ 65.36	(4,947)
All oil swap contracts			$ (28,862)

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, 2007 (Liability) (In thousands)**
Third quarter 2007	716,000	$ 51.58	$ 72.78	(1,185)
Fourth quarter 2007	689,000	$ 51.58	$ 72.81	(2,527)
2008	1,668,000	$ 50.00	$ 69.82	(11,884)
2009	1,526,000	$ 50.00	$ 67.31	(13,214)
2010	1,367,500	$ 50.00	$ 64.91	(12,824)
2011	1,236,000	$ 50.00	$ 63.70	(11,565)
All oil collars				$ (53,199)

Gas Contracts

Natural Gas Swaps

Contract Period	Volumes (MMBtu)	Weighted-Average Contract Price (Per MMBtu)	Fair Value at June 30, 2007 Asset/(Liability) (In thousands)
Third quarter 2007 -			
IF CIG	870,000	$ 6.89	2,759
IF PEPL	960,000	$ 8.05	2,008
IF NGPL	1,220,000	$ 7.74	2,004
IF ANR OK	820,000	$ 7.36	1,056
IF EL PASO	190,000	$ 7.20	185
IF HSC	380,000	$ 7.98	490
Fourth quarter 2007 -			
IF CIG	780,000	$ 7.56	1,827
IF PEPL	960,000	$ 8.69	1,976
IF NGPL	1,220,000	$ 8.07	1,696
IF ANR OK	850,000	$ 7.74	939
IF EL PASO	210,000	$ 7.17	97
IF HSC	400,000	$ 8.43	412
2008 -			
IF CIG	3,120,000	$ 7.48	1,719
IF PEPL	3,840,000	$ 8.51	4,545
IF NGPL	920,000	$ 6.99	(307)
IF ANR OK	920,000	$ 7.15	(187)
IF EL PASO	1,060,000	$ 7.22	(326)
IF HSC	1,260,000	$ 8.09	(31)
2009 -			
IF CIG	1,710,000	$ 7.79	376
IF PEPL	1,920,000	$ 8.35	1,097
IF NGPL	440,000	$ 7.11	(304)
IF ANR OK	440,000	$ 7.38	(204)
IF EL PASO	1,200,000	$ 7.11	(744)
IF HSC	940,000	$ 7.72	(491)

Natural Gas Swaps (continued)

Contract Period	**Volumes (MMBtu)**	**Weighted-Average Contract Price (Per MMBtu)**	**Fair Value at June 30, 2007 Asset/(Liability) (In thousands)**
2010 -			
IF NGPL	60,000	$ 7.60	(54)
IF ANR OK	60,000	$ 7.98	(41)
IF EL PASO	1,090,000	$ 6.79	(851)
IF HSC	140,000	$ 8.37	(82)
2011 -			
IF EL PASO	880,000	$ 6.34	(783)
All gas swap contracts			$ 18,781

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Natural Gas Collars

Contract Period	**Volumes (MMBtu)**	**Weighted-Average Floor Price (Per MMBtu)**	**Weighted-Average Ceiling Price (Per MMBtu)**	**Fair Value at June 30, 2007 Asset/(Liability) (In thousands)**
Third quarter 2007 -				
IF CIG	760,000	$ 6.41	$ 7.87	2,023
IF PEPL	1,920,000	$ 7.02	$ 9.24	2,201
IF HSC	300,000	$ 7.66	$ 9.10	317
NYMEX Henry Hub	200,000	$ 8.00	$ 9.45	248
Fourth quarter 2007 -				
IF CIG	730,000	$ 6.41	$ 7.87	1,047
IF PEPL	1,820,000	$ 7.00	$ 9.28	1,532
IF HSC	270,000	$ 7.66	$ 9.10	169
NYMEX Henry Hub	180,000	$ 8.00	$ 9.45	99
2008 -				
IF CIG	2,880,000	$ 5.60	$ 8.72	(383)
IF PEPL	6,600,000	$ 6.28	$ 9.42	297
IF HSC	960,000	$ 6.57	$ 9.70	(255)
NYMEX Henry Hub	480,000	$ 7.00	$ 10.57	(47)
2009 -				
IF CIG	2,400,000	$ 4.75	$ 8.82	(1,441)
IF PEPL	5,510,000	$ 5.30	$ 9.25	(3,072)
IF HSC	840,000	$ 5.57	$ 9.49	(575)
NYMEX Henry Hub	360,000	$ 6.00	$ 10.35	(191)
2010 -				
IF CIG	2,040,000	$ 4.85	$ 7.08	(2,019)
IF PEPL	4,945,000	$ 5.31	$ 7.61	(4,655)
IF HSC	600,000	$ 5.57	$ 7.88	(604)
NYMEX Henry Hub	240,000	$ 6.00	$ 8.38	(213)
2011 -				
IF CIG	1,800,000	$ 5.00	$ 6.32	(1,977)
IF PEPL	4,225,000	$ 5.31	$ 6.51	(5,143)
IF HSC	480,000	$ 5.57	$ 6.77	(598)
NYMEX Henry Hub	120,000	$ 6.00	$ 7.25	(131)
All gas collars				$ (13,371)

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Natural Gas Liquid Contracts

Natural Gas Liquid Swaps

Contract Period	Mont. Belvieu Volumes (Bbls)	Weighted-Average Contract Price (Per Bbl)	Fair Value at June 30, 2007 Asset/(Liability) (In thousands)
Third quarter 2007	74,588	$ 37.56	(793)
Fourth quarter 2007	78,150	$ 37.14	(853)
2008	384,081	$ 36.64	(4,259)
2009	292,202	$ 36.17	(3,207)
All natural gas liquid swaps			$ (9,112)

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Hedge Contracts Entered into After June 30, 2007

The following table includes all hedges entered into subsequent to June 30, 2007, through July 31, 2007.

Oil Swaps

Contract Period	NYMEX WTI Volumes (Bbl)	Weighted-Average Contract Price (Per Bbl)
Third quarter 2007	80,000	$ 73.03
Fourth quarter 2007	120,000	$ 73.26
2008	220,000	$ 73.51

Natural Gas Swaps

Contract Period	IF HSC Volumes (MMBtu)	Weighted-Average Contract Price (Per MMBtu)
Third quarter 2007 -	160,000	$ 5.94
Fourth quarter 2007 -	570,000	$ 7.01
2008	3,640,000	$ 8.21
2009	5,380,000	$ 8.46
2010	3,320,000	$ 8.25

Natural Gas Liquid Swaps

Contract Period	Mont. Belvieu Volumes (Bbls)	Weighted-Average Contract Price (Per Bbl)
Third quarter 2007	16,667	$ 42.84
Fourth quarter 2007	54,738	$ 42.84
2008	205,000	$ 42.84

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

Contractual Obligations

On April 4, 2007, we issued $287.5 million aggregate principal amount of 3.50% Convertible Notes. For purposes of contractual obligations, we assume that the holders of our 3.50% Convertible Notes will not exercise the conversion feature and we will therefore have to repay the $287.5 million in cash. We expect to call the 3.50% Convertible Notes for redemption in 2012. We are also obligated to make annual interest payments equal to $10.1 million.

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/A for the year ended December 31, 2006, and to the footnote disclosures 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, 2007, and 2006**			**Change Between the Six Months Ended June 30, 2007, and 2006**		
Increase in oil and gas production revenues, net of hedging (in thousands)	$	40,625		$	63,845	
Components of Revenue Increases (Decreases):						
Oil						
Realized price change per Bbl	$	0.35		$	(0.68	)
Realized price percentage change	1		%	(1		)%
Production change (MBbl)	269			450		
Production percentage change	19		%	15		%
Natural Gas						
Realized price change per Mcf	$	0.72		$	0.27	
Realized price percentage change	10		%	4		%
Production change (MMcf)	1,825			4,256		
Production percentage change	13		%	16		%

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	**2007**		**2006**		**2007**		**2006**	
Oil	46	%	47	%	44	%	45	%
Natural gas	54	%	53	%	56	%	55	%
Production								
Oil	39	%	38	%	40	%	40	%
Natural gas	61	%	62	%	60	%	60	%

Information Regarding the Components of Exploration Expense:

Summary of Exploration Expense	For the Three Months Ended June 30, 2007 (In millions)	2006	For the Six Months Ended June 30, 2007 (In millions)	2006
Geological and geophysical expenses	$ 2.3	$ 2.5	$ 4.9	$ 4.0
Exploratory dry hole expense	1.7	3.4	11.2	3.6
Overhead and other expenses	9.7	9.4	18.3	18.5
Total	$ 13.7	$ 15.3	$ 34.4	$ 26.1

Information Regarding the Effects of Oil and Gas Hedging Activity:

Oil Hedging	For the Three Months Ended June 30, 2007	2006	For the Six Months Ended June 30, 2007	2006
Percentage of oil production hedged	65 %	72 %	65 %	68 %
Oil volumes hedged (MBbl)	1,110	1,026	2,217	2,025
Decrease in oil revenue	$ (1.9 million)	$ (5.8 million)	$ (1.9 million)	$ (9.6 million)
Average realized oil price per Bbl before hedging	$ 61.11	$ 63.68	$ 56.85	$ 60.22
Average realized oil price per Bbl after hedging	$ 59.97	$ 59.62	$ 56.28	$ 56.96
Natural Gas Hedging				
Percentage of gas production hedged	46 %	38 %	46 %	39 %
Natural gas MMBtu hedged	7.8 million	5.7 million	15.3 million	11.2 million
Increase in gas revenue	$ 9.2 million	$ 10.7 million	$ 27.9 million	$ 19.6 million
Average realized gas price per Mcf before hedging	$ 7.09	$ 6.20	$ 6.96	$ 6.86
Average realized gas price per Mcf after hedging	$ 7.68	$ 6.96	$ 7.86	$ 7.59

Comparison of Financial Results and Trends between the Quarters ended June 30, 2007, and 2006

Oil and gas production revenue. Average net daily production increased 15 percent to 286.1 MMCFE per day for the second quarter of 2007, compared with 248.3 MMCFE per day for the same quarter in 2006. 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)**
Sweetie Peck acquisition and drilling, Permian Basin region	16.5	$ 15.8	$ 2.9
Williston Basin Middle Bakken Play	2.6	3.0	0.2
Elm Grove Field	6.5	4.7	0.6
Other wells completed in 2006 and 2007	55.4	37.0	5.2
Other acquisitions	4.6	3.6	0.8
Total	85.6	$ 64.1	$ 9.7

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.

Marketed gas system revenue and expense. Marketed gas system revenue increased $12.8 million to $16.0 million for the quarter ended June 30, 2007, compared with $3.2 million for the comparable period of 2006. The increase is due to the addition of a new marketed gas system that increased the number of wells for which we currently market gas, as well as an increase in production within other marketed systems. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased $12.1 million to $14.9 million for the quarter ended June 30, 2007, compared with $2.8 million for the comparable period of 2006. The net margin has stayed consistent with historical performance.

Other revenues. Other revenues increased $6.8 million to $7.7 million for the quarter ended June 30, 2007, compared with $950,000 for the comparable period of 2006. The increase is due to a $6.3 million gain associated with a global insurance settlement attributed to Hurricane Rita. The gain calculation reflects approximately $9.3 million of future costs associated with plugging and abandonment of one offshore platform. Additionally, we have accrued approximately $1.3 million of expected hurricane related damage repair costs related to our non-operated properties. We continue to closely monitor the activities associated with these properties. Any significant variation between actual and estimated plugging and abandonment and non-operated damage repair costs will impact the final determination of the insurance settlement gain. We expect adjustments to the gain to be completed by the fourth quarter of 2007.

Oil and gas production expense. Total production costs increased $7.0 million, or 16 percent, to $50.3 million for the second quarter of 2007 from $43.3 million in the comparable period of 2006. Total oil and gas production costs per MCFE increased $0.02 to $1.93 for the second quarter of 2007, compared with $1.91 for the same quarter in 2006. This increase is comprised of the following:

- A $0.04 increase in overall transportation cost due to an increase in the Rocky Mountain region resulting from a change in the sale measurement point, as well as newly drilled wells with higher transportation costs;

- Production taxes per MCFE were relatively stable increasing $0.02;

- An $0.14 increase in recurring LOE related to a continued increase in competition for oil and gas service sector resources as well as an increase in our higher cost oil properties acquired in the fourth quarter of 2006 as part of the Sweetie Peck acquisition; and

- An $0.18 overall decrease in LOE relating to workover charges, due to a decrease in workover expenses in the Rocky Mountain region.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A increased $18.7 million or 52 percent to $54.7 million for the three-month period ended June 30, 2007, compared with $35.9 million for the same period in 2006. DD&A expense per MCFE increased 32 percent to $2.10 for the three-month period ended June 30, 2007, compared to $1.59 for the same period in 2006. This increase reflects overall upward cost pressure in the industry and specifically our acquisitions and drilling in 2007 and 2006 that added costs at a higher per unit rate. In addition to the increase in the rate, our production has increased by 15 percent over the comparable periods.

Exploration Expense. Exploration expense decreased $1.6 million, or 11 percent, to $13.7 million for the second quarter of 2007, compared with $15.3 million for the comparable period of 2006. The decrease is mainly due to a $1.7 million decrease in exploratory dry hole expense.

General and administrative. General and administrative expenses increased $3.3 million or 31 percent to $13.7 million for the quarter ended June 30, 2007, compared with $10.4 million for the comparable period of 2006. G&A increased $0.07 to $0.53 per MCFE for the second quarter of 2007 compared to $0.46 per MCFE for the same three-month period in 2006.

An increase in employee count has resulted in an increase in base employee compensation, including taxes and benefits, of approximately $2.3 million between the second quarter of 2007 and the second quarter of 2006. A $900,000 increase in Net Profits Plan payments is the result of the timing of payout on newer pools. The 2004 pool reached payout status as of June 30, 2007. As of the end of the second quarter of 2007, 17 of our 20 pools are currently in payout status. No additional pools are expected to reach payout before the end of 2007.

Cash and RSU bonus expense remained relatively unchanged. Compensation expense related to stock options for the quarter ended June 30, 2007, decreased $356,000 to $162,000 from $518,000 in the comparable period in 2006 due to the vesting of options in September 2006. No stock options have been granted since 2004. Compensation expense related to the issuance of common stock to the Board of Directors for the quarter ended June 30, 2007, increased $532,000 to $711,000 from $179,000 in the comparable period in 2006 due to four of the seven non-employee directors having served on the Board for more than five years. Any director retiring after five years of service becomes fully vested in all previous equity issuances.

The above amounts combined with a net $1.3 million increase in other G&A expense, including professional fees and charitable contributions expense, were offset by a $400,000 increase in the amount of general and administrative expense that was allocated to exploration expense due to the increase in the size of our geological and exploration staff, as well as a $956,000 increase in COPAS overhead reimbursements. COPAS overhead reimbursements from operations increased due to an increase in our operated well count that resulted from our drilling and acquisition programs.

Change in Net Profits Plan Liability. For the second quarter of 2007, this non-cash expense decreased $15.2 million, resulting in a reduction of the liability of $1.2 million as opposed to non-cash expense of $14.1 million for the same quarter in 2006. This decrease reflects our estimation of the effect of an increase in oil and gas production expense, primarily from Rockies properties. This liability is a significant management estimate. Adjustments to the liability are subject to estimation and may change

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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 $35.2 million for the second quarter of 2007 and $24.0 million for the second quarter of 2006 resulting in effective tax rates of 37.3 percent and 37.4 percent, respectively. Our effective income tax rate changes from period to period as a result of changes in the mix of the highest marginal state tax rates where we do business due to acquisition and drilling activity, changes in the effect of the domestic production activities deduction, and other miscellaneous permanent differences. Our cash tax expenses decreased for the second quarter of 2007 compared to the same period of 2006 as a result of a higher level of capital spending during the second quarter of 2007 that resulted in lower estimated current taxable income. This trend is expected to continue throughout the remainder of 2007 due to our current capital program and the commodity price outlook.

Comparison of Financial Results and Trends between the six months ended June 30, 2007, and 2006

Oil and gas production revenue. Average net daily production increased 16 percent to 284.6 MMCFE per day for the six months ended June 30, 2007, compared with 246.2 MMCFE per day for the six months ended June 30, 2006. 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)
Sweetie Peck acquisition, Permian Basin region	16.6	$ 29.6	$ 5.1
Williston Basin Middle Bakken Play	3.6	6.7	0.7
Elm Grove Field	5.7	7.8	0.9
Other wells completed in 2006 and 2007	61.0	72.9	11.0
Other acquisitions	4.5	6.7	1.7
Total	91.4	$ 123.7	$ 19.4

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.

Marketed gas system revenue and expense. Marketed gas system revenue increased $14.6 million to $23.8 million for the six-month period ended June 30, 2007, compared with $9.2 million for the comparable period of 2006. The increase is due to the addition of a new marketed gas system that increased the number of wells for which we currently market gas, as well as an increase in production within other marketed systems. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased $14.2 million to $22.2 million for the six-month period ended June 30, 2007, compared with $8.0 million for the comparable period of 2006.

Other revenues. Other revenues increased $9.2 million to $8.5 million for the six-month period ended June 30, 2007, compared with a benefit of $699,000 for the comparable period of 2006. The increase is due to a $6.3 million gain associated with a global insurance settlement attributed to Hurricane Rita. The gain calculation reflects approximately $9.3 million of future costs associated with plugging and abandonment of one offshore platform. Additionally, we have accrued approximately $1.3 million of expected hurricane related damage repair costs related to our non-operated properties. We continue to closely monitor the activities associated with these properties. Any significant variation between actual and estimated plugging and abandonment and non-operated damage repair costs will impact the final determination of the insurance settlement gain. We expect adjustments to the gain to be completed by the fourth quarter of 2007.

Oil and gas production expense. Total production costs increased $18.2 million, or 21 percent, to $102.6 million for the six months ended June 30, 2007, from $84.4 million for the six months ended June 30, 2006. Total oil and gas production costs per MCFE increased $0.10 to $2.00 for the six months ended June 30, 2007, compared with $1.90 for the six months ended June 30, 2006. This increase is comprised of the following:

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

- A $0.13 increase in recurring LOE related to continued increases in competition for oil and gas service sector resources and;

- An $0.07 overall decrease in LOE relating to workover charges, mainly due to a decrease in workover expense in the Rockies.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A increased $33.3 million or 47 percent to $103.6 million for the six-month period ended June 30, 2007, compared with $70.3 million for the same period in 2006. DD&A expense per MCFE increased 27 percent to $2.01 for the six-month period ended June 30, 2007, compared to $1.58 for the same period in 2006. This increase reflects overall upward cost pressure in the industry and specifically our acquisitions and drilling in 2007 and 2006 that added costs at a higher per unit rate.

Exploration expense. Exploration expense increased $8.3 million, or 32 percent, to $34.4 million for the six-month period ended June 30, 2007, compared with $26.1 million for the comparable period of 2006. This increase is due to a $7.7 million increase in exploratory dry hole expense mainly related to two wells located in the Gulf Coast region and one in the Rockies region.

General and administrative. General and administrative expenses increased $3.6 million, or 17 percent, to $24.8 million for the six months ended June 30, 2007, compared with $21.2 million for the six months ended June 30, 2006. G&A remained flat at $0.48 per MCFE for the six months ended June 30, 2007, compared to $0.48 per MCFE for the six months ended June 30, 2006.

A 22 percent increase in employee count has resulted in an increase in base employee compensation, including taxes and benefits, of approximately $3.3 million for the six months ended June 30, 2007 compared with the same period of 2006.

Cash and RSU bonus expense remained relatively unchanged. Compensation expense related to stock options for the six months ended June 30, 2007, decreased $634,000 from $1.0 million in the comparable period in 2006 due to the vesting of options in September 2006. Compensation expense related to the issuance of common stock to the Board of Directors for the six months ended June 30, 2007, increased $537,000 to $819,000 from $282,000 in the comparable period in 2006 due to four of the seven non-employee directors having served on the Board for more than five years.

The above amounts combined with a net $1.9 million increase in other G&A expense, including professional fees and charitable contributions expense, were offset by a $1.5 million increase in COPAS overhead reimbursements. COPAS overhead reimbursements from operations increased due to an increase in our operated well count resulting from our drilling and acquisition programs.

Change in Net Profits Plan Liability. For the six months ended June 30, 2007, this non-cash expense decreased $17.3 million to $3.8 million from $21.1 million for the six months ended June 30, 2006. The decrease is due to the effect of increased oil and gas production expense, additional capital expenditures, and a deferral of revenue due to the impact of discounting future revenues in those pools currently in payout status. 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 $58.8 million for the six months ended June 30, 2007, and $53.6 million for the six months ended June 30, 2006, resulting in effective tax rates of 37.2 percent for both periods. Our cash tax expenses decreased for the six months ended June 30, 2007, compared to the same six month period of 2006 as a result of a higher level of capital spending during 2007 that resulted in lower estimated current taxable income.

Accounting Matters

We refer you to Note 6 Income Taxes of Part I, Item 1 of this report for information regarding accounting matters related to FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes .

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 Information about Forward-Looking Statements

This Quarterly Report on Form 10-Q contains 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 we expect, believe, or anticipate will or may occur in the future are forward-looking statements. The words anticipate, assume, believe, budget, estimate, expect, forecast, intend, plan, project, will, and similar expressions are intended to identify forward-looking statements. Forward-looking statements appear in a number of places in this Form 10-Q, and include statements about such matters as:

- *The amount and nature of future capital expenditures and the availability of capital resources to fund capital expenditures;*
- *the drilling of wells and other exploration and development plans, as well as possible future acquisitions;*
- *reserve estimates and the estimates of both future net revenues and the present value of future net revenues that are included in their calculation;*

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- *future oil and gas production estimates;*
- *our outlook on future oil and gas prices and service costs;*
- *cash flows, anticipated liquidity, and the future repayment of debt;*
- *business strategies and other plans and objectives for future operations, including plans for expansion and growth of operations and our outlook on future financial condition or results of operations; and*
- *other similar matters such as those discussed in the Management s Discussion and Analysis of Financial Condition and Results of Operations section of this Form 10-Q.*

Our forward-looking statements are based on 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 that we believe are appropriate under the circumstances. These statements are subject to a number of known and unknown risks and uncertainties which may cause our actual results to differ materially from results expressed or implied by the forward-looking statements. These risks are described in the Risk Factors section of our 2006 Annual Report on Form 10-K/A, and include such factors as:

- *The volatility and level of realized oil and natural gas prices;*
- *unexpected drilling conditions and results;*
- *unsuccessful exploration and development drilling;*
- *the availability and risks of economically attractive exploration, development, and property acquisition opportunities and any necessary financing;*
- *the risks of hedging strategies;*
- *lower prices realized on oil and gas sales resulting from our commodity price risk management activities;*
- *the uncertain nature of the expected benefits from the acquisition of oil and gas properties;*
- *production rates and reserve replacement;*
- *the imprecise nature of oil and gas reserve estimates;*
- *uncertainties inherent in projecting future rates of production from drilling activities and acquisitions;*
- *drilling and operating service availability;*
- *uncertainties in cash flow;*
- *the financial strength of hedge contract counterparties;*
- *the negative impact that lower oil and natural gas prices could have on our ability to borrow;*
- *our ability to compete effectively against other independent and major oil and gas companies; and*

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- *litigation, environmental matters, the potential impact of government regulations, and the use of management estimates.*

We caution you 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, and Summary of Oil and Gas Production Hedges in Place in Item 2 above and is incorporated herein by reference.

ITEM 4. CONTROLS AND PROCEDURES

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

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

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

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

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors as previously disclosed in our Form 10-K/A for the year ended December 31, 2006, in response to Item 1A of Part I of such Form 10-K/A.

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, 2007, 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	(d) Maximum Number of Shares that May Yet Be Purchased Under the Program (2)
04/01/07 04/30/07	- 0 -	$ - 0 -	-0-	6,000,000
05/01/07 05/31/07	- 0 -	$ - 0 -	-0-	6,000,000
06/01/07 06/30/07	124,689	$ 36.62	-0-	6,000,000
Total:	124,689	$ 36.62	-0-	6,000,000

(1) Includes 124,689 shares withheld (under the terms of grants under the 2006 Equity Incentive Compensation Plan) to offset tax withholding obligations that occur upon the delivery of outstanding shares underlying restricted stock units.

(2) In July 2006 the Company s Board of Directors approved an increase in the number of shares that may be repurchased under the original August 1998 authorization to 6,000,000 as of the effective date of the resolution. The shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including certain provisions of St. Mary s existing 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 that does not allow our annual dividend rate to exceed $0.25 per share.

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

At the Company s annual stockholders meeting on May 15, 2007, 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	49,178,583	4,656,765
Anthony J. Best	48,924,953	4,910,395
Larry W. Bickle	48,804,203	5,031,145
William J. Gardiner	49,516,331	4,319,017
Mark A. Hellerstein	48,941,517	4,893,831
Julio M. Quintana	53,397,325	438,023
John M. Seidl	48,264,352	5,570,996
William D. Sullivan	49,333,768	4,501,580

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	53,758,696
Against	41,310
Abstain	35,342

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ITEM 6. EXHIBITS

The following exhibits are filed or furnished with or incorporated by reference into this report:

Exhibit	**Description**
4.1	Indenture related to the 3.50% Senior Convertible Notes due 2027, dated as of April 4, 2007, between St. Mary Land & Exploration Company and Wells Fargo Bank, National Association, as trustee (including the form of 3.50% Senior Convertible Note due 2027) (filed as Exhibit 4.1 to the registrant s Current Report on Form 8-K filed on April 4, 2007).
4.2	Registration Rights Agreement, dated as of April 4, 2007, among St. Mary Land & Exploration Company and Merrill Lynch, Pierce, Fenner & Smith Incorporated and Wachovia Capital Markets, LLC, for themselves and as representatives of the Initial Purchasers (filed as Exhibit 4.2 to the registrant s Current Report on Form 8-K filed on April 4, 2007).
10.1	Purchase Agreement, dated March 29, 2007, among St. Mary Land & Exploration Company, Merrill Lynch & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Wachovia Capital Markets, LLC, Bear, Stearns & Co. Inc., BNP Paribas Securities Corp., and UBS Securities LLC (filed as Exhibit 10.1 to the registrant s Current Report on Form 8-K filed on April 4, 2007).
10.2	First Amendment to Amended and Restated Credit Agreement, dated March 19, 2007, among St. Mary Land & Exploration Company, the Lenders party thereto, Wachovia Bank, National Association, as issuing bank and administrative agent, Wells Fargo Bank, N.A., as syndication agent, and BNP Paribas, Comerica Bank-Texas and JPMorgan Chase Bank, N.A., as co-documentation agents (filed as Exhibit 10.2 to the registrant s Current Report on Form 8-K filed on April 4, 2007).
10.3	Net Profits Interest Bonus Plan, As Amended and Restated by the Board of Directors on July 19, 2007, (filed as Exhibit 10.1 to the registrant s Current Report on Form 8-K filed on July 25, 2007, and is 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.

** Furnished 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 2, 2007	By:	/s/ ANTHONY J. BEST Anthony J. Best President and Chief Executive Officer
August 2, 2007	By:	/s/ DAVID W. HONEYFIELD David W. Honeyfield Senior Vice President - Chief Financial Officer, Secretary and Treasurer
August 2, 2007	By:	/s/ MARK T. SOLOMON Mark T. Solomon Controller