ST MARY LAND & EXPLORATION CO
Form 10-Q
May 04, 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 March 31, 2007

Commission file number 001-31539

ST. MARY LAND & EXPLORATION COMPANY

(Exact name of registrant as specified in its charter)

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

1776 Lincoln Street, Suite 700, Denver, Colorado 80203

(Address of principal executive offices) (Zip Code)

(303) 861-8140

(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes 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 April 27, 2007, the registrant had 62,776,310 shares of common stock, $0.01 par value, outstanding.

ST. MARY LAND & EXPLORATION COMPANY

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(In thousands, except share amounts)

	March 31, 2007	**December 31, 2006**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 4,733	$ 1,464
Short-term investments	1,450	1,450
Accounts receivable	142,079	142,721
Refundable income taxes	4,850	7,684
Prepaid expenses and other	18,000	17,485
Accrued derivative asset	22,642	56,136
Deferred income taxes	2,980	
Total current assets	196,734	226,940
Property and equipment (successful efforts method), at cost:		
Proved oil and gas properties	2,174,265	2,063,911
Less - accumulated depletion, depreciation, and amortization	(670,401)	(630,051)
Unproved oil and gas properties, net of impairment allowance of $10,017 in 2007 and $9,425 in 2006	104,563	100,118
Wells in progress	129,217	97,498
Other property and equipment, net of accumulated depreciation of $10,197 in 2007 and $9,740 in 2006	8,034	6,988
	1,745,678	1,638,464
Noncurrent assets:		
Goodwill	9,452	9,452
Accrued derivative asset	6,331	16,939
Other noncurrent assets	6,928	7,302
Total noncurrent assets	22,711	33,693
Total Assets	**$ 1,965,123**	**$ 1,899,097**
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 195,288	$ 171,834
Short-term note payable		4,469
Accrued derivative liability	26,115	13,100
Deferred income taxes		14,667
Total current liabilities	221,403	204,070
Noncurrent liabilities:		
Long-term credit facility	350,000	334,000
Senior convertible notes		99,980
Asset retirement obligation	77,170	77,242
Net Profits Plan liability	165,548	160,583
Deferred income taxes	228,024	224,518
Accrued derivative liability	69,389	46,432
Other noncurrent liabilities	9,221	8,898

Total noncurrent liabilities	899,352	951,653
Commitments and contingencies		
Stockholders equity:		
Common stock, $0.01 par value: authorized - 200,000,000 shares; issued: 63,010,158 shares in 2007 and 55,251,733 shares in 2006; outstanding, net of treasury shares: 62,760,158 shares in 2007 and 55,001,733 shares in 2006	630	553
Additional paid-in capital	150,455	38,940
Treasury stock, at cost: 250,000 shares in 2007 and 250,000 shares in 2006	(4,203)	(4,272)
Retained earnings	732,035	695,224
Accumulated other comprehensive income (loss)	(34,549)	12,929
Total stockholders equity	844,368	743,374
Total Liabilities and Stockholders Equity	**$ 1,965,123**	**$ 1,899,097**

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

(In thousands, except per share amounts)

	For the Three Months Ended March 31, 2007	2006
Operating revenues:		
Oil and gas production revenue	$ 193,706	$ 184,065
Realized oil and gas hedge gain	18,684	5,105
Marketed gas and other operating revenue	8,616	4,418
Total operating revenues	221,006	193,588
Operating expenses:		
Oil and gas production expense	52,320	41,214
Depletion, depreciation, amortization and asset retirement obligation liability accretion	48,959	34,391
Exploration	20,769	10,787
Impairment of proved properties		1,289
Abandonment and impairment of unproved properties	1,484	1,186
General and administrative	11,141	10,786
Change in Net Profits Plan liability	4,965	7,021
Marketed gas system and other operating expense	7,952	5,759
Unrealized derivative loss	3,904	469
Total operating expenses	151,494	112,902
Income from operations	69,512	80,686
Nonoperating income (expense):		
Interest income	103	824
Interest expense	(6,053)	(1,379)
Income before income taxes	63,562	80,131
Income tax expense	(23,612)	(29,605)
Net income	**$ 39,950**	**$ 50,526**
Basic weighted-average common shares outstanding	57,011	57,233
Diluted weighted-average common shares outstanding	64,908	67,334
Basic net income per common share	**$ 0.70**	**$ 0.88**
Diluted net income per common share	**$ 0.63**	**$ 0.76**

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS) (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, $0.10 per share							(5,603)		(5,603)
Treasury stock purchases				(3,319,300)	(123,108)				(123,108)
Retirement of treasury stock	(3,275,689)	(33)	(122,598)	3,275,689	122,631				
Issuance of Directors' shares from treasury				29,827	851				851
Issuance of common stock under Employee Stock Purchase Plan	26,046		814						814
Sale of common stock, including income tax benefit of stock option exercises	1,489,636	16	32,970						32,986
Adoption of Statement of Financial Accounting Standards No. 123(R)			(5,593)			5,593			
Stock-based compensation expense			10,069	13,784	502				10,571
Balances, December 31, 2006	**55,251,733**	**$ 553**	**$ 38,940**	**(250,000)**	**$ (4,272)**	**$**	**$ 695,224**	**$ 12,929**	**$ 743,374**
Comprehensive income, net of tax:									
Net income							39,950		39,950
Change in derivative instrument fair value								(35,732)	(35,732)
Reclassification to earnings								(11,743)	(11,743)
Minimum pension liability adjustment								(3)	(3)
Total comprehensive loss									(7,528)
Cash dividends, $0.05 per share							(3,139)		(3,139)
Conversion of 5.75% Senior Convertible Notes due 2022 to common stock, including income tax benefit of conversion	7,692,295	77	106,925						107,002
Sale of common stock, including income tax benefit of stock option exercises	64,880		1,692						1,692
Stock-based compensation expense	1,250		2,898		69				2,967
Balances, March 31, 2007	**63,010,158**	**$ 630**	**$ 150,455**	**(250,000)**	**$ (4,203)**	**$**	**$ 732,035**	**$ (34,549)**	**$ 844,368**

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(In thousands)

	For the Three Months Ended March 31, 2007	2006
Reconciliation of net income to net cash provided by operating activities:		
Net income	$ 39,950	$ 50,526
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	48,959	34,391
Exploratory dry hole expense	9,569	246
Impairment of proved properties		1,289
Abandonment and impairment of unproved properties	1,484	1,186
Unrealized derivative loss	3,904	469
Change in Net Profits Plan liability	4,965	7,021
Stock-based compensation expense	2,967	3,197
Deferred income taxes	21,237	13,830
Other	(125)	134
Changes in current assets and liabilities:		
Accounts receivable	7,762	26,899
Prepaid expenses and other	2,319	416
Accounts payable and accrued expenses	(16,003)	(7,958)
Income tax benefit from the exercise of stock options	(913)	(2,404)
Net cash provided by operating activities	**126,075**	**129,242**
Cash flows from investing activities:		
Proceeds from sale of oil and gas properties	324	
Capital expenditures	(135,183)	(87,303)
Acquisition of oil and gas properties	(1,186)	(271)
Other	16	22
Net cash used in investing activities	**(136,029)**	**(87,552)**
Cash flows from financing activities:		
Proceeds from credit facility	19,000	
Repayment of credit facility	(3,000)	
Repayment of short-term note payable	(4,469)	
Income tax benefit from the exercise of stock options	913	2,404
Proceeds from sale of common stock	779	2,043
Net cash provided by financing activities	**13,223**	**4,447**
Net change in cash and cash equivalents	3,269	46,137
Cash and cash equivalents at beginning of period	1,464	14,925
Cash and cash equivalents at end of period	**$ 4,733**	**$ 61,062**

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

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 Three Months Ended March 31,	
	2007	2006
	(in thousands)	
Cash paid for interest, net of capitalized interest	$ 9,102	$ 3,527
Cash paid for (refunded from) income taxes	$ (1,815)	$ 9,832

As of March 31, 2007, and 2006, $99.0 million and $54.5 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 February 2007 and February 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 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 commons 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 cumlative excess tax benefit earned by the Company associated with the contingent interest feature of this note.

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

March 31, 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 entirely in the Continental United States.

Note 2 - Basis of Presentation and Significant Accounting Policies

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements of St. Mary have been prepared in accordance with accounting principles generally accepted in the United States for interim financial information. They do not include all information and notes required by generally accepted accounting principles for complete financial statements. However, except as disclosed herein, there has been no material change in the information disclosed in the notes to consolidated financial statements included in St. Mary s Annual Report on Form 10-K/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.

Certain amounts in the 2006 unaudited condensed consolidated financial statements have been reclassified to conform to the 2007 unaudited condensed consolidated financial statement presentation. Unrealized derivative loss has been presented as a separate line item in the accompanying financial statements for all periods presented. As a result, prior period marketed gas system and other operating expense have been reclassified to conform to current presentation.

Other Significant Accounting Policies

The accounting policies followed by the Company are set forth in Note 1 to the Company s consolidated financial statements in the Form 10-K/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 and Divestitures

There have been no significant acquisitions or divestitures in 2007.

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 the total purchase price amount, after normal 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 Company allocated the purchase price based on the estimated fair value of the assets and liabilities acquired. The final purchase price accounting allocation is expected to be completed in the second quarter of 2007.

Richland County, Montana Acquisition

On May 15, 2006, the Company closed on a transaction whereby it exchanged non-core oil and gas properties located in the Uinta Basin for oil and gas properties located in Richland County, Montana. The transaction was structured as an Internal Revenue Code Section 1031 tax-deferred exchange. For financial reporting purposes, the transaction is considered a non-monetary exchange and was accounted for at estimated fair value.

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, adjusted net income used for 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 that would have changed had the 5.75% Convertible Notes been converted at the beginning of the period. Potentially dilutive securities of the Company consist of in-the-money outstanding stock options to purchase the Company s common stock, shares into which the 5.75% Convertible Notes were convertible, and unvested RSUs.

The restricted shares underlying the grants of RSUs are included in the basic and diluted earnings per share calculations as described above. 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.

The treasury stock method is used to measure the dilutive impact of stock options. The dilutive effect of stock options and unvested RSUs is considered in the detailed calculation below. There were no anti-dilutive securities related to stock options or RSUs for the three-month periods ended March 31, 2007, and 2006.

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-month period ended March 31, 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 three-month period ended March 31, 2007, was adjusted for the conversion and included approximately 6.3 million potentially dilutive shares related to the 5.75% Convertible Notes.

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

	For the Three Months Ended March 31, 2007 (In thousands, except per share amounts)	2006
Net income	$ 39,950	$ 50,526
Adjustments to net income for dilution:		
Add: interest expense not incurred if 5.75% Convertible Notes converted	1,284	1,563
Less: other adjustments	(13)	(16)
Less: income tax effect of adjustment items	(472)	(572)
Net income adjusted for the effect of dilution	$ 40,749	$ 51,501
Basic weighted-average common shares outstanding	57,011	57,233
Add: dilutive effects of stock options and unvested RSUs	1,581	2,409
Add: dilutive effect of 5.75% Convertible Notes using the if-converted method	6,316	7,692
Diluted weighted-average common shares outstanding	64,908	67,334
Basic net income per common share	$ 0.70	$ 0.88
Diluted net income per common share	$ 0.63	$ 0.76

Note 5 Compensation Plans

Cash Bonus Plan

The Company has a cash bonus plan that allows participants to receive up to 50 percent of their aggregate base salary. Any awards under the cash bonus plan are based on a combination of Company and individual performance. The Company accrues cash bonus expense related to the current year s performance. Cash bonus expense for the three-month periods ended March 31, 2007, and 2006, was $1.2 million and $1.1 million, respectively, for the estimated cash bonus expense related to the applicable performance year.

Equity Incentive Compensation Plan

There are several components to the equity compensation plan that are described in this footnote. The various types of equity awards were granted by the Company in different periods. For example, the Company ceased issuing stock options in 2004 and began issuing restricted stock or RSUs to employees and directors. This footnote addresses the disclosure requirements for all equity awards still outstanding.

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

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 recognized in periods after December 31, 2005, 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 March 31, 2007, 2.5 million shares of common stock remained available for grant under the 2006 Equity Plan. Any issuance of a direct share benefit such as an outright grant of common stock or a grant of a restricted share or RSU counts as two shares for each share awarded against the amount eligible to be granted under the 2006 Equity Plan. Each stock option and similar instrument granted counts as one share for each share awarded against the eligible shares authorized to be issued under the 2006 Equity Plan.

St. Mary anticipates granting only restricted stock and RSUs under the 2006 Equity Plan for the foreseeable future. However, the Company does have outstanding stock option grants under the Predecessor Plans. The following sections describe the details of RSUs and stock options outstanding as of March 31, 2007.

Restricted Stock Incentive Program Under the 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. These grants are determined annually based on a 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. Vested shares of common stock underlying the RSU grants will be issued on the third anniversary of the grant, 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 48 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 are being amortized under the straight-line method since this method was allowed prior to the adoption of SFAS No. 123(R). As of March 31, 2007, there was a total of 1,138,016 RSUs outstanding, of which 722,179 were vested. Total compensation expense related to the RSUs for the three-month periods ended March 31, 2007, and

2006, was $2.6 million in each period. The 2007 period includes $1.0 million of compensation expense for vesting of the estimated value of grants expected to be issued in 2008 related to the 2007 performance year. As of March 31, 2007, there was $8.3 million of total unrecognized compensation expense related to unvested restricted stock 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 Three Months Ended March 31, 2007		**2006**	
Risk free interest rate:	4.55	%	4.70	%
Dividend yield:	0.28	%	0.26	%
Volatility factor of the market price of the Company s common stock:	32.94	%	36.60	%
Expected life of the awards (in years):	3		3	

Upon the adoption of SFAS No. 123(R) on January 1, 2006, the deferred compensation balance of $5.6 million related to outstanding RSU awards was reclassified to additional paid-in capital within the stockholders equity section of the balance sheet. This deferred compensation balance had been recorded in accordance with APB Opinion No. 25, Accounting for Stock Issued to Employees. The Company had recorded compensation expense in periods prior to January 1, 2006, for restricted stock awards based on the intrinsic value on the date of grant. The intrinsic value was recorded as deferred compensation in a separate component of stockholders equity and was amortized to compensation expense over the vesting period. SFAS No. 123(R) requires expense recognized subsequent to the adoption date to be based on fair value.

Stock Awards Under the Equity Incentive Compensation Plan

A summary of the status and activity of non-vested RSUs for the three-month period ended March 31, 2007, is presented below.

	Non-Vested RSUs		**Weighted-Average Grant-Date Fair Value**	
Non-vested, at December 31, 2006	506,161		$	28.92
Granted	82,007		$	32.11
Vested	(168,364	)	$	31.02
Forfeited	(3,967	)	$	30.75
Non-vested, at March 31, 2007	415,837		$	28.68

Stock Option Grants Under the 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 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 date 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 March 31, 2007, and 2006, the Company recognized stock-based compensation expense of approximately $221,000 and $498,000, 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).

Prior to adopting SFAS No. 123(R), all tax benefits resulting from the exercise of stock options were presented as operating cash flows in the consolidated statements of cash flows. SFAS No. 123(R) requires cash flows resulting from excess tax benefits to be classified as a part of cash flows from financing activities. Excess tax benefits are realized tax benefits from tax deductions for exercised options in excess of the deferred tax asset attributable to stock compensation costs for such options. As a result of adopting SFAS No. 123(R), $913,000 and $2.4 million of excess tax benefits for the three-month periods ended March 31, 2007, and 2006, respectively, have been classified as financing cash inflows. Cash received from option exercises under all share-based payment arrangements for the three-month periods ended March 31, 2007, and 2006, was $779,000 and $2.0 million, respectively.

The following table summarizes the stock options outstanding as of March 31, 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	(64,880)	$ 11.99		
Forfeited		$ 0.00		
Outstanding, end of period	3,056,722	$ 12.57	5.06	$ 73,699
Vested, or expected to vest, end of period	3,056,722			$ 73,699
Exercisable, end of period	2,902,064	$ 12.57	5.04	$ 69,973

As of March 31, 2007, there was $239,000 of total unrecognized compensation cost related to unvested stock option awards. The unrecognized compensation expense is being amortized through 2007.

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

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 $66,000 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 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 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 March 31, 2007 (In thousands)	2006
Liability balance for Net Profits Plan as of the beginning of the period	$ 160,583	$ 136,824
Increase in liability	10,871	13,902
Reduction in liability for cash payments made or accrued and recognized as compensation expense	(5,906)	(6,881)
Liability balance for Net Profits Plan as of the end of the period	$ 165,548	$ 143,845

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 March 31, 2007, would differ by approximately $17 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 March 31, 2007 (In thousands)	2006
General and administrative expense	$ 2,424	$ 3,196
Exploration expense	2,541	3,825
Total	$ 4,965	$ 7,021

Note 6 - Income Taxes

Income tax expense for the three-month periods ended March 31, 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 March 31, 2007 (In thousands)		2006	
Current portion of income tax expense:				
Federal	$ 1,782		$ 14,751	
State	593		1,025	
Deferred portion of income tax expense:	21,237		13,829	
Total income tax expense	$ 23,612		$ 29,605	
Effective tax rates	37.1	%	36.9	%

The change in tax rate in the current quarter from the previous year reflects differences between the two quarters in the estimated highest marginal state tax rate due to changes in the composition of income between state tax jurisdictions. It also reflects differing effects from the Company s estimate of the effect of the domestic production activities deduction, estimated 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. As of January 1, 2007, the Company had a long-term liability for unrecognized tax benefit of $1.0 million and an 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 or 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 tax authorities for years before 2003. The Internal Revenue Service completed an audit for the 2000, 2002 and 2003 tax years during the quarter ended March 31, 2007. The Company is awaiting receipt of approximately $3.8 million at March 31, 2007, 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 $350.0 million and $75.0 million in outstanding loans under its revolving credit agreement as of March 31, 2007, and April 27, 2007, respectively. The outstanding loan balance as of April 27, 2007, reflects the repayment of amounts outstanding under the revolving credit facility from the net proceeds of the 3.50% Senior Convertible Notes Due 2027 that were issued on April 4, 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 7,692,295 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% Senior Convertible Notes due 2027 (the 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.

Upon conversion of the 3.50% Convertible Notes, holders will receive cash or our 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.

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% 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.

Weighted-average Interest Rate Paid

The weighted-average interest rates paid for the first quarters of 2007 and 2006 were 6.9 percent and 8.2 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 Company capitalized interest costs of $1,327,000 and $682,000 for the three-month periods ended March 31, 2007, and 2006, respectively.

Note 8 Derivative Financial Instruments

The Company recognized a net gain of $14.5 million from its derivative contracts for the three months ended March 31, 2007, and a net gain of $4.4 million for the three months ended March 31, 2006.

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

	For the Three Months Ended March 31, 2007	2006
Derivative contract settlements included in oil and gas hedge gain	$ 18,684	$ 5,105
Ineffective portion of hedges qualifying for hedge accounting included in derivative loss	(4,025)	(836)
Non-qualified derivative contracts included in derivative gain (loss)	121	367
Interest rate derivative contract settlements included in interest expense	(283)	(275)
Total gain	$ 14,497	$ 4,361

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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. Management s Discussion and Analysis of Financial Condition and Results of Operations for details regarding the Company s hedged volumes and associated prices. As of March 31, 2007, the Company has hedge contracts in place through 2011 for a total of approximately 14 million Bbls of crude oil, 77 million MMBtu of natural gas, and 38 million gallons of natural gas liquids 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 March 31, 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 $66.5 million at March 31, 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 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 March 31, 2007, and 2006, includes a net loss of $4.0 million and $836,000, respectively, from ineffectiveness related to oil and natural gas derivative contracts.

As of March 31, 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 loss in the next twelve months is $204,000.

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 period ended March 31, 2007, and there was a net gain of $235,000 recorded for the three-month period ended March 31, 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 s employees participate in a non-contributory pension plan covering substantially all employees who meet age and service requirements (the Qualified Pension Plan). The Company also has a supplemental non-contributory pension plan covering certain management employees (the Nonqualified Pension Plan).

Components of Net Periodic Benefit Cost

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

	For the Three Months Ended March 31, 2007	**2006**
	(In thousands)	
Service cost	$ 478	$ 421
Interest cost	198	163
Expected return on plan assets	(135)	(83)
Amortization of net actuarial loss	55	74
Net periodic benefit cost	$ 596	$ 575

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

Contributions

St. Mary previously disclosed in its financial statements for the year ended December 31, 2006, that it expected to contribute approximately $2 million to the pension plans in 2007. Presently, the Company still believes it will contribute this amount during 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 March 31, 2007	**2006**
	(In thousands)	
Beginning asset retirement obligation	$ 77,242	$ 66,078
Liabilities incurred	1,594	555
Liabilities settled	(788)	(589)
Accretion expense	1,352	1,152
Revision to estimated cash flow	7,119	
Ending asset retirement obligation	$ 86,519	$ 67,196

Accounts payable and accrued expenses as of March 31, 2007, contain $9.3 million related to the Company s asset retirement obligation liability. 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.

St. Mary did not repurchase any shares of common stock under the program during the quarter ended March 31, 2007.

Note 12 Subsequent Events

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 expects to record a gain of approximately $8 to $9 million during the second quarter of 2007. The estimated gain takes into consideration approximately $9 million of future costs associated with plugging and abandonment of one off-shore platform. Any significant variation between actual and estimated plugging and abandonment costs will impact the final determination of the gain. The Company expects adjustments to the gain related to this insurance settlement to be completed by the fourth quarter of 2007.

Please see Note 7   Long-term Debt for information regarding 3.50% Convertible Notes issued subsequent to March 31, 2007.

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 95 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; and 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 for us. We believe that our regional diversity and the balance between oil and natural gas in our proved reserve are advantages which we can leverage to continue building value for our stockholders.

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 (also frequently referred to as bid week) 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 on contracts that pay us the average of the posted prices for the period in which the crude oil is produced.

The average Henry Hub bid week natural gas price increased by 15 percent and the average NYMEX West Texas Intermediate spot price decreased three percent between the fourth quarter of 2006 and first quarter of 2007. While average quarterly bid week natural gas prices increased modestly between the fourth quarter of 2006 and the first quarter of 2007, both were down substantially relative to the first quarter of 2006 when natural gas markets were still being impacted by the aftermath of Hurricanes Rita and Katrina. Futures markets for natural gas have also remained relatively stable since year end. The 36-month forward strip price for natural gas at the end of 2006 was $7.80 per MMBtu. At the end of the first quarter of 2007, the 36-month forward contract had increased four percent to $8.14 per MMBtu.

Average quarterly crude oil prices were relatively stable from the fourth quarter of 2006 to the first quarter of 2007. In the fourth quarter of 2006, NYMEX WTI crude averaged $59.96 per barrel. In the first quarter of 2007, the price averaged $58.09 per barrel. Daily spot prices surged late in March of 2007 when British military personnel were taken into custody by Iran. The situation was resolved diplomatically and oil prices subsided briefly. In recent weeks, the spot price of crude oil has increased again due in part to concerns over violence in Nigeria and a thwarted terrorist plot to attack oil facilities in Saudi Arabia. These episodes highlight the impact geopolitical events and issues have on the price of crude oil. As with natural gas, futures for crude oil have also remained relatively stable since year end. The 36-month forward strip price for crude oil at the end of 2006 was $67.21 per barrel. At the end of the first quarter of 2007, the 36-month forward contract had increased three percent to $69.08 per barrel.

While the changes in the quoted NYMEX oil and Henry Hub natural gas prices are generally used as a basis for comparison within the industry, the realized price that 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 net realized price and it 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. We refer to this price as our net realized price, including the effects of hedging.

	For the Three Months Ended March 31, 2007
Crude Oil (per Bbl) :	
NYMEX price	$ 58.27
Net realized price	$ 52.61
Net realized price, including the effects of hedging	$ 52.62
Natural Gas (per Mcf) :	
NYMEX price	$ 6.96
Net realized price	$ 6.82
Net realized price, including the effects of hedging	$ 8.04

Our natural gas price realization for the three months ended March 31, 2007, was improved by $18.7 million of realized hedging gains while our oil price realization was relatively unimpacted. The acquisition of the Sweetie Peck assets in December of 2006 added significantly to our natural gas liquids (NGL) production. The volumes and associated revenues from this production stream are accounted for as natural gas sales. However, the price of NGLs more closely tracks that of crude oil. Our reported differentials for natural gas improved in the first quarter of 2007 as a result of a full quarter s contribution of NGL production from Sweetie Peck at higher prices. Natural gas basis differentials have expanded in the Rockies during the second quarter of 2007, therefore we are expecting natural gas realizations to revert to historical levels. Oil differentials in the Rockies moderated in the first quarter of 2007. Oil differentials in the Williston Basin of approximately $5.00 per Bbl and differentials of $13.00 to $16.00 per Bbl in Wyoming for some of our sour crude are significant improvements from what we experienced in the first quarter of 2006. Reduced import volumes coming out of Canadian oil sands and syncrude projects appear to be a significant factor in the improved oil differentials in the northern United States.

Cost Environment

After several years of unabated cost escalation, we have begun to see cost reductions for some services associated with drilling operations. However, the 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 with an investment. Although we have a formal process for establishing a drilling budget, our prospect inventory and strong balance sheet give us the flexibility to adjust this budget as additional opportunities arise or as the economics of our planned activities change. As of the current time, our drilling budget for 2007 is $721 million, and we have budgeted $100 million for acquisitions.

We are seeing cost pressure related to oil and gas production costs. Oil properties are more labor intensive and our well servicing vendors are experiencing the same personnel constraints and compensation inflation as other segments of the petroleum industry. We also experienced higher than budgeted workover costs in the Rockies regions in the first quarter of 2007.

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 April 27, 2007, we have hedged approximately 14 million Bbls of oil, 77 million MMBtu of natural gas, and 38 million gallons 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.

Net Profits Plan

Payments made for distributions from the Net Profits Plan have been expensed as compensation costs in the amount of $5.9 million for the three-month period ended March 31, 2007. These 2007 payments are lower than originally budgeted due to increased oil and gas production expense, additional capital expenditures, and a decline in oil and natural gas production revenue in existing payout pools, and the timing of payout for newer pools. Actual cash payments will be inherently different from the estimated liability amount. Additional discussion is included in the analysis in the *Comparison of Financial Results and Trends* sections below.

With respect to the accounting estimate of the liability associated with future estimated payments from our Net Profits Plan, we have recorded $5.0 million of net expense for the three-month period ended March 31, 2007, thereby increasing the long-term liability associated with this item. This increase is related to an increase in the estimated prices used to calculate the liability, the accretion of the discounted liability used for the calculation, and the addition of the 2006 pool. The rate of increase for the liability associated with the Net Profits Plan should be fairly stable throughout the year based on current price projections. While we have adjusted our forecast to approximately $38 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.

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 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 realized 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 March 31, 2007, would differ by approximately $17 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.

First Quarter 2007 Highlights

In February 2007 our long-serving Chairman and CEO Mark Hellerstein retired from our day-to-day management and assumed the role of non-executive Chairman of the Board of Directors. Tony Best was appointed to the CEO position upon Mr. Hellerstein s retirement. Mr. Best served as our President during the planned transition period and continues to hold that position.

In March of 2007 we called for redemption of the then outstanding $100.0 million of 5.75% Convertible Notes. The notes had a conversion price of $13.00 per share. One hundred percent of the holders of the notes elected to convert their notes into shares of common stock. As a result of the conversion, 7.7 million shares of stock were issued to the note holders. This resulted in a decrease to long-term debt of $100.0 million, and an increase to common stock associated with the conversion together with the recognition of the excess tax benefit associated with the contingent interest feature associated with this note. Subsequent to quarter end, 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. 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.

Our net income for the quarter ended March 31, 2007, was $40.0 million or $0.63 per diluted share compared to 2006 results of $50.5 million or $0.76 per diluted share. Production for the quarter was 25.5 BCFE which represents a 16 percent increase from the same period a year ago and a two percent increase from the previous quarter. Per MCFE lease operating expense increased $0.14 to $1.34 per MCFE driven by a higher amount of expense associated with workover wells in the Northern Rockies as well as an increase in well servicing costs. Per MCFE transportation increased $0.04 to $0.17 per MCFE driven by newly drilled wells with higher transportation costs. Production taxes decreased $0.01 from the previous year s first quarter to $0.54 per MCFE. DD&A, including ARO liability accretion expense, increased $0.35 to $1.92 per MCFE as a reflection of the higher cost of drilling and acquisitions over the last year relative to the previous balances. 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 March 31, 2007, and the immediately preceding three quarters. Additional detail of per MCFE cost is contained later in this section.

	For the Three Months Ended March 31, 2007 (In millions)	December 31, 2006	September 30, 2006	June 30, 2006
Production (MCFE)	25.5	25.1	23.2	22.6
Oil and gas production revenues before the effects of hedging	$ 193.7	$ 180.6	$ 188.2	$ 178.0
Lease operating expense	$ 34.1	$ 31.2	$ 30.1	$ 28.3
Transportation costs	$ 4.4	$ 3.0	$ 2.4	$ 2.7
Production taxes	$ 13.7	$ 12.9	$ 12.5	$ 12.2
General and administrative expense	$ 11.1	$ 7.9	$ 9.7	$ 10.4
Net income	$ 40.0	$ 43.5	$ 55.9	$ 40.1
Percentage change from previous quarter:				
Production (MCFE)	2 %	8 %	3 %	3 %
Oil and gas production revenues	7 %	(4)%	6 %	(3)%
Lease operating expense	9 %	4 %	6 %	8 %
Transportation costs	47 %	25 %	(11)%	(4)%
Production taxes	6 %	3 %	2 %	2 %
General and administrative expense	41 %	(19)%	(7)%	(4)%
Net income	(8)%	(22)%	39 %	(21)%

Outlook for the Remainder of 2007

Commodity prices and oil and gas drilling and well completion service costs are the most significant drivers of our business. Natural gas and crude oil futures prices for the remainder of the year are currently higher than those used to prepare our 2007 budget. The last several years have seen a dramatic increase in the costs for drilling and completing oil and natural gas wells. Over this time period we have generally been able to access the rigs and services required to carry out our drilling program due in large part to our longstanding relationships with suppliers. While market conditions vary region by region, in recent months we have begun to realize decreases in the day rates that drilling contractors charge and we have noted that rig availability is currently less of an issue than in prior periods. We have yet to see a definitive decrease in completion costs, but we have noticed that scheduling for these services also appears to be easier compared to the first quarter of 2006. All other factors being equal, the strong commodity price and stable-to-declining completion cost environment that we are currently experiencing should allow us to continue to execute the budgeted 2007 business plan we announced earlier this year. The highlights of the 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, continuing the development of our Bakken acreage, and drilling Red River projects. We also plan to drill and re-enter wells in oil fields of the Powder River, Big Horn, and Wind River basins of Wyoming. 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. We are currently operating two rigs in the region. We have incurred $1.2 million in dry hole costs in the first quarter for one unsuccessful exploratory well.

- *Rockies - Hanging Woman Basin Coalbed Methane* Twenty-eight wells were drilled in the first quarter of 2007 and the program remains on schedule. Activity in the basin will accelerate as rigs are added this year and as winter weather conditions subside. At the end of March 2007 there were 311 wells producing and production stood at 14.7 MMcf per day gross and 8.9 MMcf per day net. The Company also plans to participate as a non-operator in a 75 well CBM program in the Atlantic Rim area of the Green River Basin.

- *Mid-Continent* Our 2007 plans in the Mid-Continent are principally centered on the Horizontal Arkoma program in eastern Oklahoma and the Atoka/Granite Wash play in the Anadarko Basin. Two operated rigs are currently working in the horizontal Arkoma program. Since mid-2006 we have refined our drilling and completion design in this play. 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. We plan to operate two to three rigs this year in the Atoka/Granite program. We also plan to spend capital in the Springer and Britt formations in 2007, as well as in the Constitution Field.

- *ArkLaTex* Activity in the ArkLaTex for 2007 is focused on two outside-operated Lower Cotton Valley programs and a horizontal carbonate program in the James limestone. The two successful Lower Cotton Valley plays are the Elm Grove and Terryville fields. At Elm Grove Field, a 20-acre increased density drilling development plan is being pursued on adjacent acreage by one of our operators. Additionally, a series of horizontal test wells have been proposed to see how that application performs in this field. We will continue to monitor these developments throughout the year. At Terryville Field, terms for development have been finalized with the operator resulting in a planned increase in activity. Five wells were originally budgeted at Terryville for 2007, and the operator has indicated that they may accelerate activity in this program. We plan to operate two rigs in the horizontal carbonate program in 2007. The vast majority of those wells will target the James limestone formation.

- *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. Net production for the Sweetie Peck assets at the end of the quarter was 2.8 MBOE per day, up from 2.6 MBOE per day at year end. We are currently operating two rigs with plans to increase to four rigs by the middle of 2007. Additional activity is planned at a non-operated tight oil program, at HJSA, and at our waterflood project in southeastern New Mexico.

- *Gulf Coast* Our 2007 plans for the Gulf Coast region consist of onshore and offshore projects in Texas and Louisiana, as well as low to moderate risk DHI prospects in the state and federal waters of the Gulf of Mexico. In the first quarter we had two exploratory successes the Clement #1 and the State Tract 236-1, both of which are expected to come online in 2007. We incurred $7.3 million in dry hole costs in the first quarter for two unsuccessful exploratory wells, one of which was an intermediate deep water project at East Breaks 369-1.

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 screen a large number of acquisitions, both in our regional offices and at our corporate headquarters. We have a strong track record of economic acquisitions. As acquisitions have become more competitive from a valuation standpoint in recent years, we have grown our inventory of drilling prospects so that we are less dependent on acquisitions to grow. Our strong balance sheet gives us the ability to move quickly when we find an acquisition target. In 2007, we will continue to evaluate acquisitions. We plan to add business development personnel and resources this year so we can more effectively determine if there are areas in the country where we currently do not operate but where we could leverage our existing technical knowledge from other regions.

A quarter-to-quarter 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 March 31, 2007	2006	% Change Between Periods
Net production volumes			
Oil (MBbl)	1,709	1,529	12 %
Natural gas (MMcf)	15,220	12,789	19 %
MMCFE (6:1)	25,476	21,962	16 %
Average daily production			
Oil (Bbl per day)	18,992	16,987	12 %
Natural gas (Mcf per day)	169,112	142,096	19 %
MCFE per day (6:1)	283,063	244,020	16 %
Oil & gas production revenues(1)			
Oil production revenue	$ 89,950	$ 83,279	8 %
Gas production revenue	122,440	105,891	16 %
Total	$ 212,390	$ 189,170	12 %
Oil & gas production expense			
Lease operating expenses	$ 34,125	$ 26,332	30 %
Transportation costs	4,447	2,847	56 %
Production taxes	13,748	12,035	14 %
Total	$ 52,320	$ 41,214	27 %
Average realized sales price(1)			
Oil (per Bbl)	$ 52.62	$ 54.47	(3)%
Natural gas (per Mcf)	$ 8.04	$ 8.28	(3)%
Per MCFE Data:			
Average net realized price(1)	$ 8.34	$ 8.61	(3)%
Lease operating expenses	(1.34)	(1.20)	12 %
Transportation costs	(0.17)	(0.13)	31 %
Production taxes	(0.54)	(0.55)	(2)%
General and administrative	(0.44)	(0.49)	(10)%
Operating profit	$ 5.85	$ 6.24	(6)%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$ 1.92	$ 1.57	22 %

(1) Includes the effects of our hedging activities

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

	March 31, 2007	December 31, 2006	% Change Between Periods
Working capital (deficit)	$ (24,669)	$ 22,870	(208)%
Long-term debt	$ 350,000	$ 433,980	(19)%
Stockholders equity	$ 844,368	$ 743,374	14 %

	For the Three Months Ended March 31, 2007	2006	% Change Between Periods
Basic net income per common share	$ 0.70	$ 0.88	(20)%
Diluted net income per common share	$ 0.63	$ 0.76	(17)%
Basic weighted-average shares outstanding	57,011	57,233	%
Diluted weighted-average shares outstanding	64,908	67,334	(4)%

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

Rapid changes in production volumes, oil and gas production revenues, and costs reflect the cyclical and highly volatile prices our industry receives for production, as well as the impact of the timing of acquisitions. The comparison of changes in production from 2007 to 2006 reflects the positive results from our drilling program in 2007 and 2006 and the impact of our acquisition made in the fourth quarter of 2006.

We present per MCFE information because we use this information to evaluate our performance relative to 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 throughout 2007 as a result of increased activity on higher cost oil projects in the Permian Basin region. Depreciation, depletion, and amortization 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 increase as a result of a new, fully-staffed Midland, Texas office, the expected $38 million expense associated with payments under our Net Profits Plan, and overall upward pressure on compensation in the exploration and production industry.

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. A detailed explanation is presented in Note 4 of 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 March 31, 2007, and 2006 reflect an increase in outstanding shares related to stock option exercises. We issued 64,880 and 210,556 shares of common stock during the three-month periods ended March 31, 2007, and 2006, respectively, as a result of stock option exercises. 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 plans for the foreseeable future.

Sources of cash

Based on our current forecast, we expect that our total 2007 capital spending under the drilling and acquisition program will exceed our cash flow generated from operations. Accordingly, we are expecting to access cash funding through the use of our revolving credit facility and the issuance of long-term debt as executed on April 4, 2007. Although we are not contemplating any property sales, in the event there are property divestitures, we would likely use these proceeds to fund our capital programs.

Our primary sources of liquidity are the cash provided by operating activities, debt financing, sales of non-strategic properties, and capital 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 this industry.

Subsequent to the quarter end, we completed the private placement of $287.5 million of 3.50% senior convertible notes. 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.

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 April 27, 2007, we had $424 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 of 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 new 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 $350.0 million as of March 31, 2007, comprised of $344.0 million of Euro-dollar based borrowing and $6.0 million of ABR borrowing. As of April 27, 2007, our total outstanding borrowings under the credit facility had been decreased to $75.0 million of Euro-dollar based borrowing and no ABR borrowing. As of March 31, 2007, we had a cash and short-term investment balance of $6.2 million.

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Our weighted-average interest rate paid in the first three months of 2007 was 6.9 percent and included fees paid on the unused portion of the credit facility aggregate commitment amount, amortization of deferred financing costs, amortization of the contingent interest embedded derivative associated with the 3.50% Convertible Notes, and the effects of interest rate swaps.

Uses of cash

We use cash for the acquisition, exploration, and development of oil and gas properties and for the payment of debt obligations, trade payables, general and administrative costs, income taxes, common stock repurchases, and stockholder dividends. In the first three months of 2007 we incurred costs of $135.2 million for capital development using cash flows from operations.

As of the date of this filing, 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 April 25, 2007, we announced that our Board declared a semi-annual dividend of $0.05 per share payable on May 14, 2007, to stockholders of record as of the close of business May 4, 2007. We have sufficient liquidity to make this payment. Our intention is to continue to make these dividend payments for the foreseeable future subject to our future earnings, our financial condition, possible credit facility covenants, and other currently unexpected factors which could arise.

The following table presents amounts and percentage changes in cash flows between the three-month periods ended March 31, 2007, and March 31, 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 Three Months Ended March 31, 2007	2006	Change	Percent Change
		(In thousands)		
Net cash provided by operating activities	$ 126,075	$ 129,242	$ (3,167)	(2)%
Net cash used in investing activities	$ (136,029)	$ (87,552)	$ (48,477)	55 %
Net cash provided by financing activities	$ 13,223	$ 4,447	$ 8,776	197 %

Analysis of cash flow changes between the three months ended March 31, 2007, and March 31, 2006

Operating activities. Cash received from oil and gas sales, net of the effects of hedging, decreased $3.7 million to $216.7 million for the three-month period ended March 31, 2007, from $220.4 million for the three-month period ended March 31, 2006. This decrease was the result of a three percent decrease in our net realized prices between the two periods in 2007. The decrease in working capital from December 31, 2006, to March 31, 2007, funded the majority of the increase in cash outflows associated with investing activities.

Investing activities. Total cash outflow for 2007 capital expenditures, as adjusted for accruals, has increased $47.9 million, or 55 percent. This increase reflects planned increases in drilling expenditures.

Financing activities. Net borrowings against our credit facility increased $16.0 million for the quarter ended March 31, 2007, compared with the same period in 2006. Net payments against our short-term note payable increased $4.5 million for the three-month period ended March 31, 2007, compared with the same period in 2006. We received $1.3 million less from the exercise of stock options in the first quarter of 2007 compared to the same period in 2006, and we had a $1.5 million decrease in the income tax benefit resulting from the exercise of stock options in the first quarter of 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. As of the date of the filing of this report, our capital expenditures forecast for drilling remains unchanged at $721 million for this year, excluding non-cash asset retirement obligation capitalized assets. Anticipated 2007 exploration and development expenditures for each of our core areas are presented in the following table.

	Exploration and Development Expenditures (In millions)
Mid-Continent region	$ 206
Rocky Mountain region	155
ArkLaTex region	131
Permian Basin region	111
Gulf Coast region	60
Hanging Woman CBM	58
	$ 721

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

The following table sets forth certain information regarding the costs incurred by us in our oil and gas property acquisition, exploration, and development activities, whether capitalized or expensed. Amounts presented include capitalized costs associated with asset retirement obligations.

	For the Three Months Ended March 31, 2007	**2006**
	(In thousands)	
Development costs	$ 132,078	$ 66,683
Exploration costs	37,147	28,509
Acquisitions:		
Proved	(443)	125
Unproved	(743)	
Leasing activity	7,812	5,977
Total, including asset retirement obligation	$ 175,851	$ 101,294

The costs we incurred for capital and exploration activities in 2007 increased $74.6 million or 74 percent compared to the same quarter in 2006. This increase was a result of planned increases in drilling activity. We have experienced significant capital cost inflation over the past three years. These cost increases explain a portion of the year-over-year increase. However, we are beginning to see a flattening of drilling and service costs and expect this to remain the case through the remainder of 2007.

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The negative $1.2 million of proved and unproved property acquisitions relate to normal purchase price adjustments related to the Sweetie Peck acquisition in the Permian Basin region.

Based on our current forecast, we expect that our total 2007 capital spending under the drilling and acquisition program will exceed our cash flow generated from operations. Accordingly, we are expecting to access cash funding either through borrowing on our revolving credit facility, the issuance of long-term debt or equity, as executed on April 4, 2007, or some combination thereof. 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 accessibility of capital markets and borrowing facilities, and the success of our development and exploratory activities could lead to changes in funding requirements for future development.

Financing alternatives

The debt and equity capital markets remain attractive to energy companies that operate in the exploration and production segment. This is a result of strong commodity prices and the general strength reflected in the balance sheets of the companies in this segment.

Subsequent to the quarter end, 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 and under the caption *Summary of Interest Rate Hedges in Place*. 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.

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 acquisition. We also hedge a portion of our forecasted production on a discretionary basis.

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

As of March 31, 2007, our hedged positions totaled approximately 14 million Bbls of crude oil, 77 million MMBtu of natural gas, and 38 million gallons of natural gas liquids anticipated future production through 2011. We seek to minimize basis risk and index the majority of our oil contracts to NYMEX prices and our gas contracts to various regional index prices associated with pipelines in proximity to our areas of gas production. The following tables describe the volumes, average contract prices, and fair value of contracts we have in place as of March 31, 2007.

Oil Contracts

Oil Swaps

Contract Period	**Volumes (Bbl)**	**Weighted-Average Contract Price (Per Bbl)**	**Fair Value at March 31, 2007 Asset/(Liability) (In thousands)**
Second quarter 2007			
NYMEX WTI	340,072	$ 59.95	$ (2,538)
IF Bow River	34,000	$ 39.74	(414)
Third quarter 2007			
NYMEX WTI	335,684	$ 60.55	(2,821)
IF Bow River	12,000	$ 39.86	(182)
Fourth quarter 2007			
NYMEX WTI	331,620	$ 61.17	(2,740)
2008			
NYMEX WTI	1,270,000	$ 67.88	(2,471)
2009			
NYMEX WTI	1,335,000	$ 67.65	(1,434)
2010			
NYMEX WTI	1,239,000	$ 66.47	(903)
2011			
NYMEX WTI	1,032,000	$ 65.36	(952)
All oil swap contracts			$ (14,455)

Oil Collars

Contract Period	NYMEX WTI Volumes (Bbl)	Weighted-Average Floor Price (Per Bbl)	Weighted-Average Ceiling Price (Per Bbl)	Fair Value at March 31, 2007 Asset/(Liability) (In thousands)
Second quarter 2007	736,000	$ 51.59	$ 72.77	$ (777)
Third quarter 2007	716,000	$ 51.58	$ 72.78	(2,019)
Fourth quarter 2007	689,000	$ 51.58	$ 72.81	(2,550)
2008	1,668,000	$ 50.00	$ 69.82	(9,787)
2009	1,526,000	$ 50.00	$ 67.31	(9,704)
2010	1,367,500	$ 50.00	$ 64.91	(8,855)
2011	1,236,000	$ 50.00	$ 63.70	(7,848)
All oil collars				$ (41,540)

Gas Contracts

Gas Swaps

Contract Period	**Volumes (MMBtu)**	**Weighted-Average Contract Price (per MMBtu)**	**Fair Value at March 31, 2007 Asset/(Liability) (in thousands)**
Second quarter 2007 -			
IF CIG	1,050,000	$ 6.88	$ 2,658
IF PEPL	960,000	$ 7.63	1,008
IF NGPL	1,040,000	$ 7.82	1,275
IF ANR OK	620,000	$ 7.62	615
IF EL PASO	180,000	$ 6.60	(3)
IF HSC	360,000	$ 7.63	102
Third quarter 2007 -			
IF CIG	870,000	$ 6.89	1,616
IF PEPL	960,000	$ 8.05	652
IF NGPL	1,220,000	$ 7.74	469
IF ANR OK	820,000	$ 7.36	(5)
IF EL PASO	190,000	$ 7.20	(52)
IF HSC	380,000	$ 7.98	26
Fourth quarter 2007 -			
IF CIG	780,000	$ 7.56	1,511
IF PEPL	960,000	$ 8.69	888
IF NGPL	1,220,000	$ 8.07	374
IF ANR OK	850,000	$ 7.74	(18)
IF EL PASO	210,000	$ 7.17	(139)
IF HSC	400,000	$ 8.43	3
2008 -			
IF CIG	3,120,000	$ 7.48	969
IF PEPL	3,840,000	$ 8.51	3,188
IF NGPL	920,000	$ 6.99	(658)
IF ANR OK	920,000	$ 7.15	(537)
IF EL PASO	1,060,000	$ 7.22	(640)
IF HSC	1,260,000	$ 8.09	(409)
2009 -			
IF CIG	1,710,000	$ 7.79	460
IF PEPL	1,920,000	$ 8.35	1,023
IF NGPL	440,000	$ 7.11	(239)
IF ANR OK	440,000	$ 7.38	(151)
IF EL PASO	1,200,000	$ 7.11	(665)
IF HSC	940,000	$ 7.72	(303)

Gas Swaps (continued)

Contract Period	Volumes (MMBtu)	Weighted-Average Contract Price (per MMBtu)	Fair Value at March 31, 2007 Asset/(Liability) (in thousands)
2010 -			
IF NGPL	60,000	$ 7.60	(36)
IF ANR OK	60,000	$ 7.98	(15)
IF EL PASO	1,090,000	$ 6.79	(591)
IF HSC	140,000	$ 8.37	(40)
2011 -			
IF EL PASO	880,000	$ 6.34	(579)
All gas swap contracts			$ 11,757

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Gas Collars

Contract Period	Volumes (MMBtu)	Weighted-Average Floor Price (per MMBtu)	Weighted-Average Ceiling Price (per MMBtu)	Fair Value at March 31, 2007 Asset/(Liability) (in thousands)
Second quarter 2007 -				
IF CIG	800,000	$ 6.41	$ 7.87	$ 1,660
IF PEPL	2,040,000	$ 7.03	$ 9.19	1,327
IF HSC	320,000	$ 7.66	$ 9.10	166
NYMEX Henry Hub	190,000	$ 8.00	$ 9.45	90
Third quarter 2007 -				
IF CIG	760,000	$ 6.41	$ 7.87	1,129
IF PEPL	1,920,000	$ 7.02	$ 9.24	561
IF HSC	300,000	$ 7.66	$ 9.10	71
NYMEX Henry Hub	200,000	$ 8.00	$ 9.45	69
Fourth quarter 2007 -				
IF CIG	730,000	$ 6.41	$ 7.87	793
IF PEPL	1,820,000	$ 7.00	$ 9.28	95
IF HSC	270,000	$ 7.66	$ 9.10	(49)
NYMEX Henry Hub	180,000	$ 8.00	$ 9.45	(56)
2008 -				
IF CIG	2,880,000	$ 5.60	$ 8.72	(823)
IF PEPL	6,600,000	$ 6.28	$ 9.42	(1,151)
IF HSC	960,000	$ 6.57	$ 9.70	(417)
NYMEX Henry Hub	480,000	$ 7.00	$ 10.57	(138)
2009 -				
IF CIG	2,400,000	$ 4.75	$ 8.82	(1,343)
IF PEPL	5,510,000	$ 5.30	$ 9.25	(2,859)
IF HSC	840,000	$ 5.57	$ 9.49	(502)
NYMEX Henry Hub	360,000	$ 6.00	$ 10.35	(159)
2010 -				
IF CIG	2,040,000	$ 4.85	$ 7.08	(1,731)
IF PEPL	4,945,000	$ 5.31	$ 7.61	(4,091)
IF HSC	600,000	$ 5.57	$ 7.88	(493)
NYMEX Henry Hub	240,000	$ 6.00	$ 8.38	(168)
2011 -				
IF CIG	1,800,000	$ 5.00	$ 6.32	(1,704)
IF PEPL	4,225,000	$ 5.31	$ 6.51	(4,526)
IF HSC	480,000	$ 5.57	$ 6.77	(484)
NYMEX Henry Hub	120,000	$ 6.00	$ 7.25	(103)
All gas collars				$ (14,836)

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Natural Gas Liquid Contracts

Natural Gas Liquid Swaps*

Contract Period	Volumes (gal)	Weighted-Average Contract Price (per gal)	Fair Value at March 31, 2007 Asset/(Liability) (in thousands)
Second quarter 2007	2,967,100	$ 0.894	$ (512)
Third quarter 2007	3,132,700	$ 0.894	(557)
Fourth quarter 2007	3,282,300	$ 0.884	(623)
2008	16,131,400	$ 0.872	(3,258)
2009	12,272,500	$ 0.861	(2,506)
All natural gas liquid swaps			$ (7,456)

*Natural gas liquid swaps are comprised of OPIS Mont. Belvieu TET Propane (34%), OPIS Mont. Belvieu Purity Ethane (32%), OPIS Mont. Belvieu NON-TET Isobutane (15%), OPIS Mont. Belvieu NON-TET Natural Gasoline (14%), and OPIS Mont. Belvieu NON-TET Normal Butane (5%).

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

Off-Balance Sheet Arrangements

We do not have any off-balance sheet financing 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.

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Additional Comparative Data in Tabular Form:

	Change Between the Three Months Ended March 31, 2007 and 2006	
Oil and gas production revenues		
Increase in oil and gas production revenues, net of hedging (In thousands)	$ 23,220	
Components of Revenue Increases (Decreases):		
Oil		
Realized price change per Bbl	$ (1.85	)
Realized price percentage change	(3	)%
Production change (MBbl)	180	
Production percentage change	12	%
Natural Gas		
Realized price change per Mcf	$ (0.24	)
Realized price percentage change	(3	)%
Production change (MMcf)	2,431	
Production percentage change	19	%

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

	For the Three Months Ended March 31, 2007		2006	
Revenue				
Oil	42	%	44	%
Natural gas	58	%	56	%
Production				
Oil	40	%	42	%
Natural gas	60	%	58	%

Information Regarding the Components of Exploration Expense:

	For the Three Months Ended March 31, 2007 (In millions)	2006
Summary of Exploration Expense		
Geological and geophysical expenses	$ 2.6	$ 1.5
Exploratory dry hole expense	9.6	0.2
Overhead and other expenses	8.6	9.1
Total	$ 20.8	$ 10.8

Information Regarding the Effects of Oil and Gas Hedging Activity:

	For the Three Months Ended March 31, 2007	2006
Oil Hedging		
Percentage of oil production hedged	65 %	65 %
Oil volumes hedged (MBbl)	1,107	998
Increase (decrease) in oil revenue	$ 28,000	$ (3.8 million)
Average realized oil price per Bbl before hedging	$ 52.61	$ 56.98
Average realized oil price per Bbl after hedging	$ 52.62	$ 54.47
Natural Gas Hedging		
Percentage of gas production hedged	46 %	40 %
Natural gas volumes hedged (MMBtu)	7.5 million	5.5 million
Increase in gas revenue	$ 18.7 million	$ 8.9 million
Average realized gas price per Mcf before hedging	$ 6.82	$ 7.58
Average realized gas price per Mcf after hedging	$ 8.04	$ 8.28

Comparison of Financial Results and Trends between the Quarters ended March 31, 2007 and 2006

Oil and gas production revenue. Average net daily production increased 16 percent to 283.1 MMCFE per day for the quarter ended March 31, 2007, compared with 244.0 MMCFE per day for the quarter ended March 31, 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, Permian Basin region	4.1	$ 13.8	$ 2.2
Williston Basin Middle Bakken Play	1.2	3.7	0.5
Elm Grove Field	1.2	3.0	0.3
Other wells completed in 2006 and 2007	18.0	35.9	5.9
Other acquisitions	1.1	3.2	0.9
Total	25.6	$ 59.6	$ 9.8

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

Oil and gas production expense. Total production costs increased $11.1 million, or 27 percent, to $52.3 million for the first quarter of 2007 from $41.2 million in the comparable period of 2006. Total oil and gas production costs per MCFE increased $0.17 to $2.05 for 2007, compared with $1.88 for 2006. This increase is comprised of the following:

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- 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 decreasing $0.01;

- An $0.11 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

- A $0.02 overall increase in LOE relating to workover charges, due to an increase in workover expenses in the Rocky Mountain region.

Depletion, Depreciation, Amortization, and Asset Retirement Obligation Liability Accretion. DD&A increased $14.6 million or 42 percent to $49.0 million for the three-month period ended March 31, 2007, compared with $34.4 million for the same period in 2006. DD&A expense per MCFE increased 22 percent to $1.92 for the three-month period ended March 31, 2007, compared to $1.57 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 $10.0 million or 93 percent to $20.8 million for the three-month period ended March 31, 2007, compared with $10.8 million for the same period in 2006. This increase is due to a $9.3 million increase in exploratory dry hole expense related to two wells located in the Gulf Coast region and one in the Rockies region.

General and administrative. General and administrative expenses increased $355,000 or 3 percent to $11.1 million for the quarter ended March 31, 2007, compared with $10.8 million for the comparable period of 2006. G&A decreased $0.05 to $0.44 per MCFE for the first quarter of 2007 compared to $0.49 per MCFE for the same three-month period in 2006.

A 19 percent increase in employee count has resulted in an increase in base employee compensation of approximately $1.2 million between the first quarter of 2007 and the first quarter of 2006. The $975,000 decrease in Net Profits Plan payments is the result of increased capital expenditures and oil and gas production expense as well as a natural decline in oil and gas production revenue in existing payout pools. As of the end of the first 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 is $175,000 higher than in the prior year, which is primarily caused by the increase in employee count. Compensation expense related to stock options decreased $278,000 to $220,000 from $498,000 in the comparable period in 2006 due to the vesting of options in September 2006. No stock options have been granted since 2004.

The above amounts combined with a net $241,000 increase in other G&A expense, including payroll tax and 401(k) contribution expense, were offset by a $456,000 decrease in the amount of general and administrative expense that was allocated to exploration expense, as well as a $522,000 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 quarter ended March 31, 2007, this non-cash expense was $5.0 million compared to $7.0 million for 2006. This decrease reflects our estimation of the effect of increased capital expenditures, oil and natural gas production expense, a natural decline in oil and natural gas production revenue in existing payout pools, and the timing of payout for newer pools. 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.

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Note 5 Compensation Plans

Income taxes. Income tax expense totaled $23.6 million for the first quarter of 2007 and $29.6 million for the first quarter of 2006 resulting in effective tax rates of 37.1 percent and 36.9 percent, respectively. The effective rate change from 2006 reflects changes in the mix of the highest marginal state tax rates as a result of acquisition and drilling activity and also reflects other permanent differences including differing estimated effects between years of the domestic production activities deduction. Our cash tax expenses decreased for the first quarter of 2007 compared to the same period of 2006 as a result of a higher level of capital spending during the first quarter of 2007, resulting in lower current taxable income. This trend is expected to continue throughout the remainder of 2007 given the current capital program and commodity price outlook.

Accounting Matters

We refer you to Note 6 of Part I, Item 1 of this report for information regarding accounting matters.

Environmental

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

Cautionary 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;*
- *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*

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- *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*
- *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, Summary of Oil and Gas Production Hedges in Place, and Summary of Interest Rate Hedges in Place in Item 2 above and is incorporated herein by reference.

ITEM 4. CONTROLS AND PROCEDURES

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

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

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

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

ITEM 1A. RISK FACTORS

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

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).
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

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* Filed with this report.

** Furnished with this report.

SIGNATURES

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

ST. MARY LAND & EXPLORATION COMPANY

May 4, 2007	By:	/s/ ANTHONY J. BEST Anthony J. Best President and Chief Executive Officer
May 4, 2007	By:	/s/ DAVID W. HONEYFIELD David W. Honeyfield Senior Vice President - Chief Financial Officer, Secretary and Treasurer
May 4, 2007	By:	/s/ MARK T. SOLOMON Mark T. Solomon Controller

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