ST MARY LAND & EXPLORATION CO
Form 10-Q
May 05, 2008

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, 2008

Commission file number 001-31539

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

Delaware (State or other jurisdiction of incorporation or organization)	41-0518430 (I.R.S. Employer Identification No.)
1776 Lincoln Street, Suite 700, Denver, Colorado (Address of principal executive offices)	80203 (Zip Code)

(303) 861-8140
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes þ No o

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

Large accelerated filer þ	Accelerated filer o
Non-accelerated filer o (Do not check if a	Smaller reporting

smaller reporting company) company 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 þ

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 25, 2008, the registrant had 61,519,532 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)

ASSETS		March 31, 2008		December 31, 2007
Current assets:				
Cash and cash equivalents	$	7,511	$	43,510
Short-term investments		1,187		1,173
Accounts receivable		200,385		159,149
Refundable income taxes		-		933
Prepaid expenses and other		12,022		14,129
Accrued derivative asset		1,181		17,836
Deferred income taxes		58,956		33,211
Total current assets		281,242		269,941
Property and equipment (successful efforts method), at cost:				
Proved oil and gas properties		2,851,809		2,721,229
Less - accumulated depletion, depreciation, and amortization		(823,410)		(804,785)
Unproved oil and gas properties, net of impairment allowance of $9,554 in 2008 and $10,319 in 2007		153,148		134,386
Wells in progress		146,932		137,417
Oil and gas properties held for sale less accumulated depletion, depreciation, and amortization		27,181		76,921
Other property and equipment, net of accumulated depreciation of $11,940 in 2008 and $11,549 in 2007		9,755		9,230
		2,365,415		2,274,398
Noncurrent assets:				
Goodwill		9,452		9,452
Accrued derivative asset		1,744		5,483
Other noncurrent assets		12,434		12,406
Total noncurrent assets		23,630		27,341
Total Assets	$	2,670,287	$	2,571,680
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities:				
Accounts payable and accrued expenses	$	285,481	$	254,918
Accrued derivative liability		156,345		97,627
Deposit associated with oil and gas properties held for sale		-		10,000

Total current liabilities		441,826		362,545
Noncurrent liabilities:				
Long-term credit facility		276,500		285,000
Senior convertible notes		287,500		287,500
Asset retirement obligation		100,171		96,432
Asset retirement obligation associated with oil and gas properties held for sale		1,104		8,744
Net Profits Plan liability		225,032		211,406
Deferred income taxes		289,050		257,603
Accrued derivative liability		235,795		190,262
Other noncurrent liabilities		9,813		8,843
Total noncurrent liabilities		1,424,965		1,345,790
Commitments and contingencies				
Stockholders' equity:				
Common stock, $0.01 par value: authorized - 200,000,000 shares;				
issued: 61,501,825 shares in 2008 and 64,010,832 shares in 2007;				
outstanding, net of treasury shares: 61,301,725 shares in 2008				
and 63,001,120 shares in 2007		615		640
Additional paid-in capital		64,923		170,070
Treasury stock, at cost: 200,100 shares in 2008 and 1,009,712 shares in 2007		(2,804)		(29,049)
Retained earnings		971,570		878,652
Accumulated other comprehensive loss		(230,808)		(156,968)
Total stockholders' equity		803,496		863,345
Total Liabilities and Stockholders' Equity	$	2,670,287	$	2,571,680

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

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ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)
(In thousands, except per share amounts)

	For the Three Months Ended March 31,	
	2008	2007
Operating revenues:		
Oil and gas production revenue	$ 310,432	$ 193,706
Realized oil and gas hedge gain (loss)	(23,950)	18,684
Marketed gas system and other operating revenue	19,603	8,616
Gain on sale of proved properties	56,017	-
Total operating revenues	362,102	221,006
Operating expenses:		
Oil and gas production expense	59,476	52,320
Depletion, depreciation, amortization and asset retirement obligation liability accretion	70,354	48,959
Exploration	14,308	19,019
Abandonment and impairment of unproved properties	1,008	1,484
General and administrative	21,128	12,891
Change in Net Profits Plan liability	13,626	4,965
Marketed gas system and other operating expense	18,445	7,952
Unrealized derivative loss	6,417	3,904
Total operating expenses	204,762	151,494
Income from operations	157,340	69,512
Nonoperating income (expense):		
Interest income	97	103
Interest expense	(4,971)	(6,053)
Income before income taxes	152,466	63,562
Income tax expense	(56,470)	(23,612)
Net income	$ 95,996	$ 39,950
Basic weighted-average common shares outstanding	62,861	57,011
Diluted weighted-average common shares outstanding	64,045	64,908
Basic net income per common share	$ 1.53	$ 0.70
Diluted net income per common share	$ 1.50	$ 0.63

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	Retained Earnings	Accumulated Other Comprehensive Income(Loss)	Total Stockholders' Equity
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	-	-	-	-	-	189,712	-	189,712
Change in derivative instrument fair value	-	-	-	-	-	-	(154,497)	(154,497)
Reclassification to earnings	-	-	-	-	-	-	(15,470)	(15,470)
Minimum pension liability adjustment	-	-	-	-	-	-	70	70
Total comprehensive income								19,815
Cash dividends, $ 0.10 per share	-	-	-	-	-	(6,284)	-	(6,284)
Treasury stock purchases	-	-	-	(792,216)	(25,957)	-	-	(25,957)
Issuance of common stock under Employee Stock Purchase Plan	29,534	-	919	-	-	-	-	919
Conversion of 5.75% Senior Convertible Notes due 2022 to common stock, including income tax benefit of conversion	7,692,295	77	106,854	-	-	-	-	106,931
Issuance of common stock upon settlement of								

RSUs following expiration of restriction period, net of shares used for tax withholdings	302,370	3	(4,569)	-	-	-	-	(4,566)
Sale of common stock, including income tax benefit of stock option exercises	733,650	7	19,011	-	-	-	-	19,018
Stock-based compensation expense	1,250	-	8,915	32,504	1,180	-	-	10,095
Balances, December 31, 2007	64,010,832	$ 640	$ 170,070	(1,009,712)	$ (29,049)	$ 878,652	$ (156,968)	$ 863,345
Comprehensive income, net of tax:								
Net income	-	-	-	-	-	95,996	-	95,996
Change in derivative instrument fair value	-	-	-	-	-	-	(88,921)	(88,921)
Reclassification to earnings	-	-	-	-	-	-	15,080	15.080
Minimum pension liability adjustment	-	-	-	-	-	-	1	1
Total comprehensive income								22,156
Cash dividends, $ 0.05 per share	-	-	-	-	-	(3,078)	-	(3,078)
Treasury stock purchases	-	-	-	(2,135,600)	(77,150)	-	-	(77,150)
Retirement of treasury stock	(2,945,212)	(29)	(103,237)	2,945,212	103,266	-	-	-
Issuance of common stock upon settlement of RSUs following expiration of restriction period, net of shares used for tax withholdings	408,829	4	(6,275)	-	-	-	-	(6,271)
Sale of common stock, including income								

tax benefit of stock option exercises	27,376	-	1,184	-	-	-	-	1,184
Stock-based compensation expense	-	-	3,181	-	129	-	-	3,310
Balances, March 31, 2008	61,501,825	$ 615	$ 64,923	(200,100)	$ (2,804)	$ 971,570	$ (230,808)	$ 803,496

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, 2008	2007
Cash flows from operating activities:		
Reconciliation of net income to net cash provided by operating activities:		
Net income	$ 95,996	$ 39,950
Adjustments to reconcile net income to net cash provided by operating activities:		
Gain on sale of proved properties	(56,017)	-
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	70,354	48,959
Exploratory dry hole expense	690	9,569
Abandonment and impairment of unproved properties	1,008	1,484
Unrealized derivative loss	6,417	3,904
Change in Net Profits Plan liability	13,626	4,965
Stock-based compensation expense (1)	3,310	2,967
Deferred income taxes	50,089	21,237
Other	3,627	(125)
Changes in current assets and liabilities:		
Accounts receivable	(41,236)	7,762
Refundable income taxes	933	-
Prepaid expenses and other	(336)	2,319
Accounts payable and accrued expenses	(5,142)	(16,003)
Income tax benefit from the exercise of stock options	(860)	(913)
Net cash provided by operating activities	142,459	126,075
Cash flows from investing activities:		
Proceeds from sale of oil and gas properties	130,400	324
Capital expenditures	(161,306)	(135,183)
Acquisition of oil and gas properties	(53,031)	(1,186)
Other	(10,007)	16
Net cash used in investing activities	(93,944)	(136,029)

Cash flows from financing activities:				
Proceeds from credit facility		389,000		19,000
Repayment of credit facility		(397,500)		(3,000)
Repayment of short-term note payable		-		(4,469)
Income tax benefit from the exercise of stock options		860		913
Proceeds from sale of common stock		328		779
Repurchase of common stock		(77,202)		-
Net cash provided by (used in) financing activities		(84,514)		13,223
Net change in cash and cash equivalents		(35,999)		3,269
Cash and cash equivalents at beginning of period		43,510		1,464
Cash and cash equivalents at end of period	$	7,511	$	4,733

(1) Stock-based compensation expense is a component of exploration expense and general and administrative expense on the consolidated statements of operations. During the periods ended March 31, 2008, and 2007, respectively, $1.1 million and $1.0 million of stock-based compensation expense was included in exploration expense. During the periods ended March 31, 2008, and 2007, respectively, $2.2 million and $1.9 million of stock-based compensation expense was included in general and administrative expense.

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

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

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

	For the Three Months Ended March 31,	
	2008	2007
	(in thousands)	
Cash paid for interest, net of capitalized interest	$ 3,616	$ 9,102
Cash paid (refunded) for income taxes	$ 2,081	$ (1,815)

As of March 31, 2008, and 2007, $132.8 million and $99.0 million, respectively, are included as additions to oil and gas properties and as increases to accounts payable and accrued expenses. These oil and gas property additions are reflected in cash used in investing activities in the periods that the payables are settled.

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

In June 2006 the Company hired a new senior executive. In March 2008 and February 2007 the Company issued 3,750 and 1,250 shares of stock, respectively, to the senior executive, as the Company reached certain performance levels. The total value of these issuances was $136,425 and $45,475, respectively.

In February 2008 and February 2007, the Company issued 158,744 and 78,657 restricted stock units, respectively, pursuant to the Company's restricted stock plan. The total value of the issuances were $6.0 million and $2.5 million, respectively.

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

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

March 31, 2008

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, 2007. In the opinion of management, all adjustments, consisting of normal recurring accruals that are 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 2007 amounts in the unaudited consolidated financial statements have been reclassified to correspond to the 2008 presentation. As a result of a change in circumstances in 2007, the Company began classifying payments made under the Net Profits Interest Bonus Plan (the “Net Profits Plan”), to exploration overhead for individuals who are currently employed by St. Mary and who continue to be involved in the Company’s exploration efforts. As a result of the change, distributions being made and accrued for under the Net Profits Plan for former employees are now fully allocated to general and administrative expense since there is no longer any functional link to geologic and geophysical or exploration related work by those former employees. The entire impact for 2007 was recorded in the fourth quarter. The quarterly financial information presented for 2007 throughout the accompanying unaudited consolidated financial statements has been reclassified to reflect the change. The reclassification had no impact on total operating expenses, income from operations, income before income taxes, net income, basic net income per share, or diluted net income per share as it was simply a reclassification between two line items within the accompanying consolidated statements of operations. Refer to Note 14 of Part II, Item 8 within the Form 10-K/A for the year ended December 31, 2007, for further discussion.

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, 2007, 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, 2007.

Note 3 – Acquisitions, Divestitures, Variable Interest Entities, and Assets Held for Sale

Carthage Acquisition

On March 21, 2008, the Company acquired oil and gas properties located primarily in the Carthage Field in Panola County, Texas in exchange for $49.7 million of cash. After normal purchase price adjustments of $219,000, the Company allocated $29.8 million to proved oil and gas properties and $20.5 million to unproved oil and gas properties. The Company also recorded $390,000 in asset retirement obligation liability associated with the acquired properties. The acquisition was funded with cash on hand and borrowings under the Company's existing credit facility.

Abraxas Divestiture

On January 31, 2008, the Company completed the divestiture of certain non-strategic oil and gas properties located primarily in the Rocky Mountain and Mid-Continent regions to Abraxas Petroleum Corporation and Abraxas Operating, LLC. The cash received at closing, net of commission costs, was $129.6 million. The final sale price is subject to normal post-closing adjustments and is expected to be finalized during the second quarter of 2008. The estimated gain on sale of proved properties related to the divestiture is approximately $56.0 million and may be impacted by the above mentioned forthcoming post-closing adjustments. The Company determined that these sales do not qualify for discontinued operations accounting under Financial Accounting Standards Board ("FASB") Emerging Issues Task Force Issue No. 03-13.

Rockford Acquisition

On October 4, 2007, the Company completed the purchase of certain oil and gas properties in the Gold River Project Area targeting the Olmos shallow gas formation located primarily in Webb and Dimmit Counties, Texas. The assets were purchased from Rockford Energy Partners II, LLC for $148.9 million of cash, which is net of normal purchase price adjustments of $2.1 million. The acquisition was funded with cash on hand and borrowings under the Company's existing revolving credit facility. The Company allocated $127.3 million to proved oil and gas properties, $23.0 million to unproved oil and gas properties, and a net $292,000 to other assets. The Company also recorded $1.7 million in asset retirement obligation liability associated with the acquired properties. This property acquisition is adjacent to the Catarina project area. The Company has hedged the equivalent of the first three years of natural gas production and the first two years of associated natural gas liquids production related to this acquisition.

Like-Kind Exchanges and Variable Interest Entities

The Carthage acquisition described above was structured to qualify as the first step of a reverse like-kind exchange under Section 1031 of the Internal Revenue Code of 1986, as amended, ("the IRC") and I.R.S. Revenue Procedure 2000-37. Prior to closing on the acquisition, the Company assigned all of its rights and duties under the purchase and sale agreement to NBF Reverse Exchange, LLC, an indirect wholly-owned subsidiary of Comerica Incorporated, which further assigned all of its rights and duties under the purchase and sale agreement to St. Mary Acquisition, LLC ("SMA, LLC"), a company unaffiliated with St. Mary. The Carthage Field assets were acquired by NBF Reverse Exchange, LLC as an exchange accommodation titleholder. SMA, LLC will hold the assets pursuant to a qualified exchange accommodation agreement until the second step of the like-kind exchange is completed. As of the date of closing on March 21, 2008, the assets held by SMA, LLC, are being leased by St. Mary under a triple net lease whereby St. Mary has the benefit and risk of all revenues and costs attributed to the properties. The Carthage Field assets are managed by St. Mary under the terms of a management agreement with SMA, LLC.

In connection with the reverse like-kind exchange described above, St. Mary loaned an amount equal to the purchase price of the assets to SMA, LLC. Based on the provisions of FASB Interpretation No. 46(R), “Consolidation of Variable Interest Entities” (“FIN 46(R)”), the Company determined that SMA, LLC is a variable interest entity for which St. Mary is the primary beneficiary. Accordingly, SMA, LLC was consolidated into St. Mary subsequent to the completion of the purchase of oil and gas properties on March 21, 2008. As a result of the consolidation, St. Mary recognized all oil and gas reserves and production as well as all revenues and expenses attributed to the Carthage acquisition beginning on March 21, 2008.

The Rockford acquisition of the Gold River assets was also structured to qualify as the first step of a reverse like-kind exchange under Section 1031 of the IRC, and I.R.S. Revenue Procedure 2000-37. Prior to closing on the Rockford acquisition, the Company assigned all of its rights and duties under the purchase and sale agreement to NBF Reverse Exchange, LLC, an indirect wholly-owned subsidiary of Comerica Incorporated, which further assigned all of its rights and duties under the purchase and sale agreement to St. Mary Land & Exploration Acquisition, LLC (“SMLEA, LLC”), a company unaffiliated with St. Mary. The Gold River assets were acquired by NBF Reverse Exchange, LLC as an exchange accommodation titleholder. SMLEA, LLC held the assets pursuant to a qualified exchange accommodation agreement until January 31, 2008, when the second step of the like-kind exchange was completed in conjunction with the divestiture of certain non-core oil and gas properties discussed above under Abraxas Divestiture and St. Mary acquired all of the limited liability company interests of SMLEA, LLC from NBF Reverse Exchange, LLC. As of the date of closing on October 4, 2007, through February 7, 2008, the assets held by SMLEA, LLC, were leased by St. Mary under a triple net lease whereby St. Mary enjoyed the benefits and risks of all revenues and costs attributed to the properties. The Gold River assets were managed by St. Mary under the terms of a management agreement with SMLEA, LLC. On February 7, 2008, the Gold River assets were transferred to St. Mary. As of this filing date SMLEA, LLC, is inactive and does not hold any assets.

In connection with the reverse like-kind exchange described in the preceding paragraph, St. Mary loaned an amount equal to the purchase price of the assets to SMLEA, LLC. Based on the provisions of FIN No. 46(R), the Company determined that SMLEA, LLC is a variable interest entity for which St. Mary is the primary beneficiary. Accordingly, SMLEA, LLC was consolidated into St. Mary subsequent to the completion of the purchase of oil and gas properties on October 4, 2007. As a result of the consolidation, St. Mary recognized all oil and gas reserves and production as well as all revenues and expenses attributed to the Rockford acquisition beginning on October 4, 2007. The loan was repaid on February 7, 2008.

Assets Held for Sale

As of March 31, 2008, the Company is engaged in marketing for sale certain non-core oil and gas properties located in the Rocky Mountain, Gulf Coast, and Mid-Continent regions. In accordance with Statement of Financial Accounting Standards No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets”, these properties have been separately presented in the balance sheet at the lower of net book value or fair value less the cost to sell. The accompanying consolidated balance sheet as of March 31, 2008, presents $27.2 million of assets held for sale, net of $10.1 million of accumulated depletion, depreciation and amortization. Asset retirement obligation liabilities of $1.1 million related to these properties have also been reclassified to liabilities associated with oil and gas properties held for sale on the consolidated balance sheet as of March 31, 2008. The Company determined that these sales do not qualify for discontinued operations accounting under FASB Emerging Issues Task Force Issue No. 03-13.

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 for the respective 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. Potentially dilutive securities for the diluted earnings per share calculations consist of unvested RSUs, in-the-money outstanding options to purchase the Company's common stock, and shares into which the 3.50% Senior Convertible Notes due 2027 (the "3.50% Senior Convertible Notes") are convertible.

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.

Prior to the March 16, 2007, conversion of the Company's 5.75% Senior Convertible Notes due 2022 (the "5.75% Senior Convertible Notes"), potentially dilutive shares associated with this instrument were accounted for using the if-converted method for the determination of diluted earnings per share. Adjusted net income used in the if-converted method was derived by adding interest expense paid on the 5.75% Senior Convertible Notes back to net income and then adjusting for nondiscretionary items that are based on net income and would have changed had the 5.75% Senior Convertible Notes been converted at the beginning of the period. The 5.75% Senior 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 7.7 million common shares in connection with the conversion of the 5.75% Senior Convertible Notes. Upon conversion, these shares were included in the calculation of weighted-average common shares outstanding. 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% Senior Convertible Notes.

The Company's 3.50% Senior Convertible Notes, which were issued April 4, 2007, have a net-share settlement right, and the treasury stock method is used to measure the potentially dilutive impact of shares associated with that conversion feature. The 3.50% Senior Convertible Notes have not been dilutive at any point during the time they have been outstanding and therefore do not impact the diluted earnings per share calculation for the three-month period ended March 31, 2008.

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, 2008, and 2007.

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

	For the Three Months Ended March 31,			
	2008		2007	
	(In thousands, except per share amounts)			
Net income	$	95,996	$	39,950
Adjustments to net income for dilution:				
Add: interest expense not incurred if 5.75% Senior Convertible Notes converted		-		1,284
Less: other adjustments		-		(13)
Less: income tax effect of adjustment items		-		(472)
Net income adjusted for the effect of dilution	$	95,996	$	40,749
Basic weighted-average common shares outstanding		62,861		57,011
Add: dilutive effects of stock options and unvested RSUs		1,184		1,581
Add: dilutive effect of 5.75% Senior Convertible Notes using the if-converted method		-		6,316
Diluted weighted-average common shares outstanding		64,045		64,908
Basic net income per common share	$	1.53	$	0.70
Diluted net income per common share	$	1.50	$	0.63

Note 5 – Compensation Plans

Cash Bonus Plan

The Company has a cash bonus plan, under which the Company has established a performance measurement framework whereby selected employee participants can generally be awarded an annual cash bonus of up to a maximum of 50 percent of their aggregate base salary. As the plan is currently administered, any awards under the plan are based on Company and regional performance, and then are further refined by individual performance. As amended by the Board of Directors on March 28, 2008, the plan document provides that no participant may receive an annual bonus under the plan of more than 200 percent of his or her base salary. The Company accrues cash bonus expense related to the current year's performance. The Company paid $3.5 million for cash bonuses in February 2008 related to the 2007 performance year and paid $1.8 million in February 2007 related to the 2006 performance year. Included in the general and administrative and exploration expense line items in the accompanying consolidated statements of operations are $1.8 million and $1.2 million of cash bonus expense related to the specific performance year for the three-month periods ended March 31, 2008, and 2007, respectively.

Equity Incentive Compensation Plan

There are several components to equity compensation that are described in this section. Various types of equity awards have been granted by the Company in different periods. For example, the Company ceased issuing stock options and began issuing restricted stock or RSUs to employees and directors in 2004.

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Effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123(R), “Share Based Payment” (“SFAS No.123(R)”) using the modified-prospective transition method. Under that transition method, compensation expense recognized in 2007 and 2008, 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 Statement of Financial Accounting Standards No. 123, “Accounting for Stock-Based Compensation”, 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, 2008, 2.4 million shares of common stock remained available for grant under the 2006 Equity Incentive Compensation Plan (the “2006 Equity Plan”). 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”). For any issuance of a direct share benefit such as an outright grant of common stock, a grant of a restricted share, or a RSU grant, each direct share benefit issued counts as two shares against the number of shares available to be granted under the 2006 Equity Plan. Stock options granted count as one share for each instrument issued against the number of shares available to be granted under the 2006 Equity Plan.

St. Mary has decided to grant Performance Share Plan (“PSP”) awards beginning in the third quarter of 2008 in place of RSUs and the Net Profits Plan as the primary form of long-term equity incentive compensation for certain employees. The performance shares are expected to be subject to vesting periods and pre-established performance conditions. PSP awards will result in tradable shares of St. Mary common stock being issued immediately upon final vesting at the end of the planned three-year performance measurement period. Pending stockholder approval of an amendment and restatement of the 2006 Equity Plan at the Company's 2008 annual stockholders' meeting to be held on May 21, 2008, the Company expects that awards granted under the PSP will be granted under the 2006 Equity Plan as amended and restated as of March 31, 2008. The Company does have outstanding stock option grants under the Predecessor Plans and RSU grants under the Predecessor Plans and the 2006 Equity Plan. The following sections describe the details of RSU grants and stock options outstanding as of March 31, 2008.

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 158,744 RSUs on February 29, 2008, related to 2007 performance and 78,657 RSUs on February 28, 2007, related to 2006 performance. The total fair value associated with these issuances was $6.0 million in 2008 and $2.5 million in 2007 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. For RSUs awarded prior to 2006, vested shares of common stock underlying the RSU grants were issued on the third anniversary of the grant, at which time the shares carried no further restrictions. For all awards subsequent to the 2005 RSU grant, St. Mary has eliminated the restriction period that extends beyond the vesting period so that shares will be issued without restriction upon vesting, rather than on the third anniversary of the award. This change was effected within the safe harbor adoption provisions of the newly enacted U.S. Treasury regulations interpreting IRC laws governing deferred compensation. The mutual election of the employee and the Company were required to effect this change for each outstanding award. Essentially all of the awards were modified for this mutual election, and as such the incremental value associated with removing this restriction period will be amortized over the remaining service period for these awards. For grants made beginning with 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. As of March 31, 2008, a total of 259,146 RSUs were outstanding, of which 8,027 were vested. Total RSU compensation expense for the three-month periods ended March 31, 2008 and 2007 was $3.1 million and $2.6 million, respectively. This amount includes $1.2 million of compensation expense related to the 2008 equity plan year for vesting of the estimated value of RSUs expected to be granted in mid 2008. As of March 31, 2008, there was $5.5 million of total unrecognized compensation expense related to unvested RSU awards. The unrecognized compensation expense is being amortized through 2011.

St. Mary also issued 2,600 and 3,350 RSUs for various grants to certain employees during the three-month periods ended March 31, 2008 and 2007, respectively. These grants have various vesting schedules. The fair value of these awards will be recorded to compensation expense over the respective vesting periods using the same basic framework as described above.

On February 28, 2008, the Company converted 400,794 RSUs, which were granted on February 28, 2006, February 28, 2007, and February 28, 2008, into common stock based on the amended terms of the RSU awards. On March 14, 2008, the Company converted 169,701 RSUs that were granted on March 15, 2005, into common stock based on the original terms of the RSU awards. The Company and the majority of the grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and original award agreements. As a result, the Company issued a net 402,653 shares of common stock associated with these grants. The remaining 167,842 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon the delivery of the shares underlying those RSUs.

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. For grants prior to January 1, 2008 the Company had a restriction period beyond vesting. Therefore, the fair value of the RSUs was inherently less than the market value of an unrestricted share of St. Mary's common stock. The fair value of RSUs had been measured using the Black-Scholes option-pricing model. The Company's computation of expected volatility was based on the historic volatility of St. Mary's common stock. The Company's computation of expected life was determined based on historical experience of similar awards, giving consideration to the contractual terms of the awards, vesting schedules, and expectations of future employee behavior. The interest rate for periods within the contractual life of the award was based on the U.S. Treasury constant maturity yield at the time of grant.

The fair values of RSUs granted in the three-month period ended March 31, 2007 were estimated using the following weighted-average assumptions:

	2007
Risk free interest rate:	4.55%
Dividend yield:	0.28%
Volatility factor of the market price of the Company's common stock:	32.94%
Expected life of the awards (in years):	3

Beginning January 1, 2008, RSU awards no longer have a restriction beyond vesting. Therefore fair value of an RSU is equal to the market value of the underlying stock on the date of the grant.

Stock Awards Under the Equity Incentive Compensation Plan

As part of hiring a new senior executive in the second quarter of 2006, St. Mary granted a special stock award whereby the employee may earn an additional 5,000 shares over a four-year period, beginning in 2006, and an additional 15,000 shares if certain net asset value growth targets are met over that period. The fair value of this award is being recorded as compensation expense over the vesting period. In March 2008 and February 2007 the Company issued 3,750 and 1,250 shares of stock, respectively, to the senior executive. The total value of these issuances was $136,425 and $45,475, respectively.

A summary of the status and activity of non-vested RSUs for the three-month period ended March 31, 2008, is presented in the following table.

	Non-Vested RSUs	Weighted-Average Grant-Date Fair Value
Non-vested, at December 31, 2007	289,385	$ 32.26
Granted	163,844	$ 37.85
Vested	(192,678)	$ 32.61
Forfeited	(9,432)	$ 35.12
Non-vested, at March 31, 2008	251,119	$ 35.41

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. 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 underlying 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, 2008, and 2007, the Company recognized stock-based compensation expense of approximately $11,000 and $221,000, respectively, related to stock options that were outstanding and unvested 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 accompanying 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. The Company has recorded $860,000 and $913,000 of excess tax benefits for the three-month periods ended March 31, 2008, and 2007, respectively, as cash inflows from financing activities. Cash received from option exercises for the three-month periods ended March 31, 2008, and 2007, was $324,000 and $779,000, respectively.

The following table summarizes the stock options outstanding as of March 31, 2008:

	Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (In years)	Aggregate Intrinsic Value (In thousands)
Outstanding, beginning of period	2,385,500	$ 12.62		
Exercised	(27,376)	$ 11.82		
Forfeited	-	$ 0.00		
Outstanding, end of period	2,358,124	$ 12.63	4.18	$ 61,015
Vested, or expected to vest, end of period	2,358,124			$ 61,015
Exercisable, end of period	2,350,624	$ 12.62	4.18	$ 60,823

As of March 31, 2008, there was $6,000 of total unrecognized compensation cost related to unvested stock option awards.

Employee Stock Purchase Plan

Under the St. Mary Land & Exploration Company Employee Stock Purchase Plan (“the ESPP”), eligible employees may purchase shares of the Company’s common stock through payroll deductions of up to 15 percent of eligible compensation. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on the first or last day of the purchase period, and shares issued under the ESPP are restricted for a period of 18 months from the date issued. The ESPP is intended to qualify under Section 423 of the IRC. The Company has set aside 2,000,000 shares of its common stock to be available for issuance under the ESPP, of which 1,599,811 shares are available for issuance as of March 31, 2008. The fair value of ESPP grants is measured at the date of grant using the Black-Scholes option-pricing model. There were no shares issued under the ESPP in the first quarter of 2008 or 2007. The Company expensed $75,000 and $66,000 based on the estimated fair value on the respective grant date for the three-month periods ended March 31, 2008, and 2007, respectively.

Net Profits Plan

Under the Company’s 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. The 2006 and 2007 pool years 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. The 2006 and 2007 pool years include a cap whereby the maximum benefit to participants from a particular year’s pool is limited to 300 percent of a participating individual’s adjusted base salary paid during the year to which the pool relates. In

December 2007 the Board approved a restructuring of the Company’s incentive compensation programs. The change in the incentive compensation structure is designed to replace the current RSU and Net Profits Plan programs with a single long-term equity incentive compensation program utilizing performance shares. As a result, pending stockholder approval of an amendment and restatement of the Company's 2006 Equity Plan, the 2007 Net Profits Plan pool is expected to be the last pool established by the Company.

The Company records changes in the present value of estimated future payments under the Net Profits Plan as a separate item in the accompanying 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 results realized in the current period. The table below presents the estimated allocation of the expense related to the change in the Net Profits Plan liability if the Company did allocate the adjustment to these specific functional line items based on the current allocation of actual distributions being made by the Company. The change in allocation of costs to the functional classification relates to the current composition of employees as compared to those individuals that have terminated employment with the Company. For the three-month periods ended March 31, 2008, and 2007, 20 percent and 22 percent, respectively, of payments made under the Net Profits Plan were classified as exploration expense in the accompanying consolidated statements of operations. As time progresses, less of the distribution relates to prospective exploration efforts as more of the distributions are made to employees that have terminated employment and thereby do not provide any ongoing exploration support.

	For the Three Months Ended March 31,	
	2008	2007
	(In thousands)	
General and administrative expense	$ 10,907	$ 3,894
Exploration expense	2,719	1,071
Total	$ 13,626	$ 4,965

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Note 6 - Income Taxes

Income tax expense for each of the three-month periods ended March 31, 2008, and 2007, differs from the amounts that would be provided by applying the statutory U.S. federal income tax rate to income before income taxes primarily due to the effect of state income taxes, percentage depletion, the estimated effect of the domestic production activities deduction, and other permanent differences.

	For the Three Months Ended March 31,	
	2008	2007
	(In thousands)	
Current portion of income tax expense		
Federal	$ 5,881	$ 1,782
State	500	593
Deferred portion of income tax expense	50,089	21,237
Total income tax expense	$ 56,470	$ 23,612
Effective tax rates	37.0%	37.1%

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

The Company 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 2004. The Internal Revenue Service completed audits for the 2000, 2002, and 2003 tax years during the quarter ended March 31, 2007. There was no change to the provision for income tax as a result of these examinations. On April 24, 2008, the Internal Revenue Service initiated an audit of the Company’s 2005 tax year.

In 2007 the Company received a $3.1 million refund of income tax and interest from a carryback of net operating losses to the 2000 tax year. An additional $980,000 was received in the first quarter of 2008 for income tax refunds and accrued interest resulting from a carry-over of minimum tax credits to the 2003 tax year. These amounts have been previously recognized by the Company.

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 March 31, 2008, the Company had a long-term liability of $1.0 million related to this item. 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 accompanying consolidated statements of operations. Penalties associated with income tax are recorded in general and administrative expense in the accompanying consolidated statements of operations.

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 the majority of the Company's oil and gas properties and the common stock of any material subsidiaries of the Company. The borrowing base under the credit facility as authorized by the bank group as of the date of this filing is $1.4 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 is in compliance with all financial and non-financial covenants under the credit facility. The payment of dividends is subject to covenants under the Company's existing credit facility, including the requirement that the Company maintain certain levels of stockholders' equity and the limitation of the Company's annual dividend rate to no more than $0.25 per share per year. Interest and commitment fees are accrued based on the borrowing base utilization percentage table below. Euro-dollar loans accrue interest at London Interbank Offered Rate ("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 accompanying 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 $276.5 million and $270.0 million outstanding under its revolving credit agreement as of March 31, 2008, and April 25, 2008, respectively.

5.75% Senior Convertible Notes Due 2022

The Company called for redemption of its 5.75% Senior 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% Senior Convertible Note holders converted all $100 million of the 5.75% Senior Convertible Notes to common shares at a conversion price of $13.00 per share. The Company issued 7.7 million common shares in connection with the conversion.

3.50% Senior Convertible Notes Due 2027

On April 4, 2007, the Company issued $287.5 million aggregate principal amount of 3.50% Senior Convertible Notes. The 3.50% Senior Convertible Notes mature on April 1, 2027, unless earlier converted, redeemed, or purchased by the Company. The 3.50% Senior 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% Senior 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 specified thresholds or the trading price of the notes falls below specified thresholds, (2) if the notes are called for redemption, (3) if specified distributions to holders of the Company's common stock are made or specified corporate transactions occur, (4) if a fundamental change occurs, or (5) during the ten trading days prior to, but excluding, the maturity date. The notes and underlying shares have been registered under a shelf registration statement. If the Company becomes involved in a material transaction or corporate development, it may suspend trading of the 3.50% Senior Convertible Notes under the prospectus. In the event the suspension period exceeds 45 days within any three-month period or 90 days within any twelve-month period, the Company will be required to pay additional interest to all holders of the 3.50% Senior Convertible Notes, not to exceed a rate per annum of 0.50 percent of the issue price of the 3.50% Senior Convertible Notes; provided that no such additional interest shall accrue after April 4, 2009.

Upon conversion of the 3.50% Senior Convertible Notes, holders will receive cash or common stock or any combination thereof as elected by the Company. At any time prior to the maturity date of the notes, the Company has the option to unilaterally and irrevocably elect to net share 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% Senior Convertible Notes, and (2) if the conversion value exceeds $1,000, the Company will also deliver, at its election, cash or common stock or a combination of cash and common stock with respect to the remaining value deliverable upon conversion. Currently, it is the Company's intention to net share settle the 3.50% Senior Convertible Notes. However, the Company has not made this a formal legal irrevocable election and thereby reserves the right to settle the 3.50% Senior Convertible Notes in any manner allowed under the offering memorandum as business conditions warrant.

If a holder elects to convert the 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 the 3.50% Senior Convertible Notes. In addition, the Company will pay contingent interest in cash, commencing with any six-month period beginning on or after April 1, 2012, if the average trading price of a note for the five trading days ending on the third trading day immediately preceding the first day of the relevant six-month period equals 120 percent or more of the principal amount of the 3.50% Senior Convertible Notes.

On or after April 6, 2012, the Company may redeem for cash all or a portion of the 3.50% Senior 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% Senior 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 percent 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. Based on the market price of the 3.50% Senior Convertible Notes, the estimated fair value of the notes was approximately $293 million as of March 31, 2008.

Weighted-Average Interest Rate Paid and Capitalized Interest Costs

The weighted-average interest rates paid for the first quarters of 2008 and 2007 were 5.2 percent, and 6.9 percent, respectively, including commitment fees paid on the unused portion of the credit facility aggregate commitment, amortization of deferred financing costs, amortization of the contingent interest embedded derivative associated with the 5.75% Senior Convertible Notes for 2007, and the effect of interest rate swaps. The average outstanding loan balance during the first quarter of 2008 increased in comparison to 2007, while the rates associated with the balances decreased for the same periods. As such, the weighted-average interest rate decreased. Capitalized interest costs for the Company for the three-month periods ended March 31, 2008, and 2007, were $1.2 million and $1.3 million, respectively.

Note 8 – Derivative Financial Instruments

Oil and Gas Commodity Hedges

To mitigate a portion of the potential exposure to adverse market changes, the Company has entered into various derivative contracts. The Company'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, 2008, the Company has hedge contracts in place through 2011 for a total of approximately 11 million Bbls of anticipated crude oil production, 77 million MMBtu of anticipated natural gas production, and 1 million Bbls of anticipated natural gas liquids production.

The Company attempts to qualify its oil and natural gas derivative instruments as cash flow hedges for accounting purposes under Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS No. 133"), and related pronouncements. 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 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. If hedge accounting is discontinued and the derivative remains outstanding, the Company will recognize all subsequent changes in its fair value on the Company's consolidated statements of operations for the period in which the change occurs. As of March 31, 2008, all oil and natural gas 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 oil and natural gas derivative contracts designated and qualifying as cash flow hedges under SFAS No. 133 was a net liability balance of $388.3 million at March 31, 2008. The Company realized a net loss of $23.9 million and a net gain of $18.7 million from its oil and gas derivative contracts for the three-month periods ended March 31, 2008, and 2007, respectively.

After-tax 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 upon the sale of the hedged production. As of March 31, 2008, the amount of unrealized loss net of deferred income taxes to be reclassified from accumulated other comprehensive income to oil and gas production operating revenues in the next twelve months was $92.7 million.

Any change in fair value resulting from ineffectiveness is recognized currently in unrealized derivative loss in the accompanying consolidated statements of operations. Unrealized derivative loss for the three-month periods ended March 31, 2008, and 2007, includes net losses of $6.4 million and $4.0 million, respectively, from ineffectiveness related to oil and natural gas derivative contracts.

Gains or losses from the settlement of oil and gas derivative contracts are reported in the total operating revenues section of the accompanying consolidated statements of operations.

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

	For the Three Months Ended March 31, 2008	2007
Derivative contract settlements included in oil and gas hedge gain	$ (23,950)	$ 18,684
Ineffective portion of hedges qualifying for hedge accounting included in derivative loss	(6,417)	(4,025)
Non-qualified derivative contracts included in derivative gain	-	121
Interest rate derivative contract settlements included in interest expense	(121)	(283)
Total gain (loss)	$ (30,488)	$ 14,497

Interest Rate and Convertible Note Derivative Instruments

In relation to the Company's 5.75% Senior Convertible Notes converted in March 2007, the Company entered into a fixed-to-floating interest rate swap on $50 million of principal in October 2003, and entered into a floating-to-fixed rate swap for this same notional amount of $50 million in April 2005 in order to effectively offset the initial fixed-to-floating interest rate swap.

In September 2007 the Company entered into a one year floating-to-fixed interest rate derivative contract for a notional amount of $75 million. Under the agreement, the Company will pay a fixed rate of 4.90 percent and will be paid a variable rate based on the one-month LIBOR rate. The interest rate derivative contract is measured at fair value using quoted prices in active markets. The liability in the accompanying consolidated balance sheets at March 31, 2008, was $901,000. The interest rate swap is a straightforward, non-complex, non-structured instrument that is highly liquid. This derivative qualifies for cash flow hedge treatment under SFAS No. 133 and related pronouncements. The Company recorded a net derivative gain of $121,000 in the accompanying consolidated statements of operations for the three-month period ended March 31, 2008, related to this interest rate derivative contract.

The contingent interest provision of the 3.50% Senior Convertible Notes is a derivative instrument. As of March 31, 2008, the value of the derivative was determined to be immaterial.

Note 9 – Pension Benefits

The Company has a non-contributory pension plan covering substantially all employees who meet age and service requirements (the "Qualified Pension Plan"). The Company also has a supplemental non-contributory pension plan covering certain management employees (the "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,	
	2008	2007
	(In thousands)	
Service cost	$ 460	$ 478
Interest cost	222	198
Expected return on plan assets	(168)	(135)
Amortization of net actuarial loss	40	55
Net periodic benefit cost	$ 554	$ 596

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 or 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, 2007, that it expected to contribute approximately $2.9 million to the pension plans in 2008. Presently, the Company still believes it will contribute this amount during 2008.

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 accompanying 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 accompanying 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,	
	2008	2007
	(In thousands)	
Beginning asset retirement obligation	$ 108,284	$ 77,242
Liabilities incurred	4,029	1,594
Liabilities settled	(10,597)	(788)
Accretion expense	1,665	1,352
Revision to estimated cash flow	600	7,119
Ending asset retirement obligation	$ 103,981	$ 86,519

Asset retirement obligation of $1.1 million related to properties classified as oil and gas properties held for sale as of March 31, 2008. There was no asset retirement obligation related to oil and gas properties held for sale as of March 31, 2007.

Accounts payable and accrued expenses contain $2.7 million and $9.3 million related to the Company's asset retirement obligation liability for the periods ended March 31, 2008, and 2007, respectively. 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 during the second quarter of 2008. Please refer to Note 13 – Insurance Settlement for additional details.

Note 11 – Fair Value Measurements

Effective January 1, 2008, the Company adopted Statement of Financial Accounting Standards No. 157, "Fair Value Measurements" ("SFAS No. 157") for all financial assets and liabilities measured at fair value on a recurring basis. The statement establishes a framework for measuring fair value and requires enhanced disclosures about fair value measurements. SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The statement establishes market or observable inputs as the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The statement establishes a hierarchy for grouping these assets and liabilities, based on the significance level of the following inputs:

- Level 1 – Quoted prices in active markets for identical assets or liabilities
- Level 2 – Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable
- Level 3 – Significant inputs to the valuation model are unobservable.

The following is a listing of our liabilities required to be measured at fair value on a recurring basis and where they are classified within the hierarchy as of March 31, 2008 (in thousands):

	Level 1	Level 2	Level 3
Liabilities			
Net accrued derivative liability	$ --	$ 389,215	$ -
Net Profits Plan	-	-	225,032
Total	$ -	$ 389,215	$ 225,032

A financial asset or liability is categorized within the hierarchy based upon the lowest level of input that is significant to the fair value measurement. Following is a description of the valuation methodologies used by the Company as well as the general classification of such instruments pursuant to the hierarchy.

Derivatives

Below is a general description of the Company's valuation methodologies for derivative financial assets and liabilities, which are measured at fair value and are included in the accompanying consolidated balance sheets. The Company uses Level 2 inputs to measure the fair value of oil and gas hedges and the interest rate swap. Fair values are based upon interpolated data. The Company derives internal valuation estimates taking into consideration the counterparties' credit rating, the Company's credit rating, and the time value of money and then compares that to the counterparties' mark-to market statements. The considered factors result in an estimated exit-price for each asset or liability under a marketplace participant's view. Management believes that this approach provides a reasonable, non-biased, verifiable, and consistent methodology for valuing derivative instruments.

Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value due to the credit quality of the counterparty. Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. Therefore, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. The Company monitors the counterparties' credit ratings and may ask counterparties to post collateral if their ratings deteriorate. In some instances the Company will attempt to novate the trade with a more stable counterparty.

Valuation adjustments are necessary to reflect the effect of the Company's credit quality on the fair value of any net liability position with a counterparty. This adjustment takes into account any credit enhancements, such as collateral margin that the Company may have posted with a counterparty, as well as any letters of credit between the parties. The methodology to determine this adjustment is consistent with how we evaluate counterparty credit risk, taking into account the Company's credit rating, current credit spreads, as well as any change in such spreads since the last measurement date. The majority of the Company's derivative counterparties are members of St. Mary's secured bank syndicate. We are currently in a net liability position with our counterparties.

The methods described above may result in a fair value estimate that may not be indicative of net realizable value or may not be reflective of future fair values and cash flows. While the Company believes that the valuation methods utilized are appropriate and consistent with the requirements of SFAS No. 157 and with other marketplace participants, the Company recognizes that third parties may use different methodologies or assumptions to determine the fair value of certain financial instruments that could result in a different estimate of fair value at the reporting date.

Commodity Derivative Assets and Liabilities - The Company has a variety of derivatives including commodity swaps and collars for the sale of oil, natural gas and natural gas liquids. Standard oil and gas activities expose the Company to varying degrees of commodity price risk. To mitigate a portion of this risk, the Company may enter into natural gas, crude oil and natural gas liquid derivatives to lock in a specific margin in conjunction with acquisition decisions or when market conditions are favorable. The Company values these derivatives using index prices, mark-to-market statements received from counterparties, and the Company's credit adjusted borrowing rate, and also factors in the time value of money. As the value is derived from numerous factors, all of the Company's commodity trading derivatives are classified as having Level 2 inputs.

Interest Rate Derivative Assets and Liabilities – The Company has one interest rate swap agreement in place for a notional amount of $75 million. This instrument effectively causes a portion of the Company's floating rate debt to become fixed rate debt and is held with a major financial institution, which is expected to, and is expecting the Company to, fully perform under the terms of the agreement. A mark-to-market valuation that takes into consideration anticipated cash flows from the transaction using quoted market prices, other economic data and assumptions, and pricing indications used by other market participants is used to value the swap. Given the degree of varying assumptions used to value the swap, it is deemed to be a Level 2 instrument.

Net Profits Plan

The Net Profits Plan is a standalone liability for which there is no available market price, principal market or market participants. The inputs available for this instrument are unobservable, and are therefore classified as Level 3 inputs. The Company employs the income approach, which converts future amounts to a single present value amount. This technique uses the estimate of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the time value of money, the risk premium, and nonperformance risk to calculate the fair value. There is a direct correlation between performance and the Net Profits Plan pool liability. If performance is substandard, the liability is reduced or eliminated.

The Company records the estimated fair value of the long-term liability for estimated 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 12 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 commodity price and cost assumptions and the 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. This average price is adjusted to include the effect of hedge prices for the percentage of forecasted production hedged in the relevant periods. The forecasted non-cash expense associated with this significant management estimate is highly volatile from period to period due to fluctuations that occur in the crude oil and natural gas commodity markets. Higher commodity prices experienced in recent years have moved more pools into payout status. The Company continually evaluates the assumptions used in this calculation in order to consider the current market environment for oil and gas prices, costs, discount rates, and overall market conditions.

As noted above, the calculation of the estimated liability for the Net Profits Plan is also 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, 2008, would differ by approximately $21 million. A one percentage point decrease in the discount rate would result in an increase to the liability of approximately $14 million, while a one percentage point increase in the discount rate would result in a decrease to the liability of approximately $13 million. Actual cash payments to be made to participants 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 may be inherently different from the amounts estimated.

No published market quotes exist on which to base the Company's estimate of fair value of the Net Profits Plan. As such, the recorded fair value is based entirely on the management estimates that are described within this footnote. While some inputs to the Company's calculation of the fair value of the Net Profits Plan's future payments are from published sources, others, such as the discount rate and the expected future cash flows, are derived from the Company's own calculations and estimates.

The following table reflects the activity for the liabilities measured at fair value using Level 3 inputs for the quarter ended March 31, 2008, (in thousands):

		Net Profits Plan Liability
Balance at December 31, 2007	$	211,406
Net increase (decrease) in liability (a)		35,156
Net settlements (a) (b)		(21,530)
Transfers in (out) of Level 3		-
Balance at March 31, 2008	$	225,032

(a) Net changes in the Net Profits Plan liability are shown in the Change in Net Profits Plan liability line item of the accompanying consolidated statements of operations.

(b) Settlements represent cash payments made or accrued for and recognized as compensation expense.

See Note 8 - Derivative Financial Instruments, and Note 5 - Compensation Plans, for more information regarding the Company's hedging instruments and the Net Profits Plan, respectively.

Note 12 – Repurchase and Retirement of Common Stock

Stock Repurchase Program

During the first quarter of 2008 St. Mary repurchased 2,135,600 shares of its outstanding common stock in the open market at a weighted-average price of $36.13 per share, including commissions, for a total of $77.1 million. As of the date of this filing, the Company has Board authorization to repurchase up to 3,072,184 additional 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 revolving credit facility. Additionally, in March 2008, the Company's Board of Directors approved a resolution to retire 2,945,212 shares of treasury stock.

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

Note 13 – Insurance Settlement

In April 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 was approximately $33 million. The Company has experienced significant weather-related delays in its plug and abandonment efforts and consequently accrued an additional $600,000 of plug and abandonment costs for one offshore platform during the first quarter of 2008, bringing the total plug and abandonment costs accrued for the platform to $12.7 million. As of March 31, 2008, the

Company has spent $10.0 million for plug and abandonment costs associated with this platform. Any significant variation between actual and estimated plugging and abandonment and outside-operated damage repair costs will impact the final determination of the gain associated with the insurance settlement. The Company expects adjustments to the gain to be completed by the second quarter of 2008.

Note 14 – Recent Accounting Pronouncements

In September 2006 the FASB issued SFAS No. 157, which defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. Where applicable, this statement simplifies and codifies fair value related guidance previously issued within generally accepted accounting principles. SFAS No. 157 was effective for the Company on January 1, 2008. The Company partially adopted SFAS No. 157 pursuant to FASB Staff Position No. FAS 157-2, "Effective Date of FASB Statement No. 157" ("FSP No. FAS 157-2"), which delayed the effective date of SFAS No. 157 for all nonrecurring fair value measurements of nonfinancial assets and nonfinancial liabilities until fiscal years beginning after November 15, 2008. FSP No. FAS 157-2 states that a measurement is recurring if it happens at least annually and defines nonfinancial assets and nonfinancial liabilities as all assets and liabilities other than those meeting the definition of a financial asset or financial liability in Statement of Financial Accounting Standards No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" ("SFAS No. 159"). The statement also notes that if SFAS No. 157 is not applied in its entirety, the Company must disclose (1) that it has only partially adopted SFAS No. 157 and (2) the categories of assets and liabilities recorded or disclosed at fair value to which the statement was not applied.

The Company adopted FSP No. FAS 157-2 as of January 1, 2008, and elected to partially adopt SFAS No. 157. The Company did not apply SFAS No. 157 to nonrecurring fair value measurements of nonfinancial assets and nonfinancial liabilities, including nonfinancial long-lived assets measured at fair value for an impairment assessment under Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets", and asset retirement obligations initially measured at fair value under Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations". The Company is still required to apply SFAS No. 157 to recurring financial and non-financial instruments, which affects the fair value disclosure of our financial derivatives within the scope of SFAS No. 133. The partial adoption of SFAS No. 157 did not have a material impact on the Company's consolidated financial statements. Please see Note 11 – Fair Value Measurements.

In February 2007 the FASB issued SFAS No. 159, which expands the use of fair value accounting but does not affect existing standards that require assets or liabilities to be carried at fair value. SFAS No. 159 allows entities to choose, at specified election dates, to use fair value to measure eligible financial assets and liabilities that are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item's fair value in subsequent reporting periods must be recognized in current earnings. SFAS No. 159 also establishes presentation and disclosure requirements designed to draw comparisons between entities that elect different measurement attributes for similar assets and liabilities. SFAS No. 159 was effective for the Company on January 1, 2008. The Company did not elect the fair value option. There was no impact on the Company's consolidated financial statements.

In December 2007 the FASB issued Statement of Financial Accounting Standards No. 141(R), "Business Combinations" ("SFAS No. 141(R)"), which requires the acquiring entity in a business combination to recognize and measure all assets and liabilities assumed in the transaction and any non-controlling interest in the acquiree at fair value as of the acquisition date. The statement also establishes guidance for the measurement of the acquirer shares issued in consideration for a business combination, the recognition of contingent consideration, the accounting treatment for pre-acquisition gain and loss contingencies, the treatment of acquisition related transaction costs, and the recognition of changes in the acquirer's income tax valuation allowance and deferred taxes. SFAS No. 141(R) is effective for fiscal years beginning after December 15, 2008, and is to be applied prospectively as of the beginning of the fiscal year in which the statement is applied. Early adoption is not permitted. SFAS No. 141(R) will be effective for the Company beginning with the 2009 fiscal year. The Company is currently evaluating the potential impact of SFAS No. 141(R) on its consolidated financial statements, but the nature and magnitude of the specific effects will depend upon the nature, terms, and size of the acquisitions the Company consummates after the effective date.

In December 2007 the FASB issued Statement of Financial Accounting Standards No. 160, “Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51” (“SFAS No. 160”), which establishes accounting and reporting standards that require noncontrolling interests to be reported as a component of equity. The statement also requires that changes in a parent's ownership interest while the parent retains its controlling interest be accounted for as equity transactions and that any retained noncontrolling equity investment upon the deconsolidation of a subsidiary be initially measured at fair value. SFAS No. 160 is effective for fiscal years beginning after December 15, 2008, and is to be applied prospectively as of the beginning of the fiscal year in which the statement is applied. The Company will be required to adopt SFAS No. 160 beginning with its 2009 fiscal year. The Company is currently evaluating the potential impact, if any, of the adoption of SFAS No. 160 on its accompanying consolidated financial statements when effective.

In March 2008 the FASB issued Statement of Financial Accounting Standards No. 161, “Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133” (“SFAS No. 161”), which requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. The statement requires fair value disclosures of derivative instruments and their gains and losses to be in tabular format, potential effect on the entity’s liquidity from the credit-risk-related contingent features to be disclosed, and cross-referencing within the footnotes. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The Company will be required to adopt SFAS No. 161 beginning with its 2009 fiscal year. The Company is currently evaluating the potential impact, if any, of the adoption of SFAS No. 161 on its accompanying consolidated financial statements when effective.

In March 2008 the FASB affirmed the staff’s proposed position paper on convertible debt instruments, likely to be called FASB Staff Position APB 14-a, “Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (including Partial Cash Settlement)” (“FSP APB 14-a”), which establishes bifurcation accounting for cash option settlement bonds. The position states that bonds would be valued without the conversion feature and would be classified as debt and that the remaining proceeds would be recorded as equity to represent the cash settlement option. Amortization of the bond discount will result in increased interest expense on the statement of operations. The position would also yield lower earnings per share dilution than typical convertible bonds. FSP APB 14-a is effective at the start of years beginning after December 15, 2008. The Company will be required to adopt FSP APB 14-a beginning with its 2009 fiscal year.   FSP APB 14-a must be applied retrospectively; existing bonds will not be grandfathered. The Company is currently evaluating the potential impact on its financial statements of the adoption of FSP APB 14-a, which the Company currently expects will apply to the 3.50% Senior Convertible Notes, but as of the date of filing of this Form 10-Q the final position paper for FSP 14-a has not yet been issued.

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. Our recurring revenues and cash flows are generated almost entirely from the sale of produced natural gas and crude oil. Our oil and gas reserves and operations are concentrated primarily in the following areas:

- Various Rocky Mountain basins, including the Williston, Big Horn, Wind River, Powder River, and Greater Green River basins
- The Anadarko and Arkoma basins of the Mid-Continent
- The Permian Basin
- The productive reservoirs of East Texas and North Louisiana
- The producing formations in the greater Maverick Basin in South Texas
- The onshore Gulf Coast and offshore Gulf of Mexico.

We have developed a balanced and diverse portfolio of proved reserves, development drilling opportunities, and unconventional resource projects.

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. We believe that our regional diversity and the balance between oil and natural gas in our reserves are advantages we can leverage while building value for our stockholders.

First Quarter 2008 Highlights

On January 31, 2008, we completed the divestiture of certain non-strategic oil and gas properties located primarily in the Rocky Mountain and Mid-Continent regions to Abraxas Petroleum Corporation and Abraxas Operating, LLC. The cash received at closing was $129.6 million, net of commission costs and customary closing adjustments. The Company used the proceeds to pay down outstanding bank borrowings under its revolving credit facility. The economics of the transaction were further enhanced by utilizing a tax-advantaged exchange structure that will allow us to defer most, if not all, of the gain on the sale. Primarily due to the divestiture, we recorded a $56.0 million gain on sale of proved properties during the first quarter of 2008.

On March 21, 2008, we closed on the acquisition of predominantly natural gas properties located in the Carthage Field in Panola County, Texas. Total cash paid for the acquisition was $49.7 million, net of customary closing adjustments. The acquisition was funded with cash on hand and borrowings under our existing revolving credit facility. Some portion or all of this acquisition may be included in a tax-advantaged exchange structure in 2008. We have initially estimated proved reserves associated with this acquisition of approximately 25 BCFE.

On March 21, 2008, David W. Honeyfield, Senior Vice President-Chief Financial Officer and Secretary, resigned as an officer of the Company to pursue a professional opportunity in the mining industry. As of the date of this filing, an external search is underway for his replacement.

Throughout the first quarter of 2008 we repurchased a total of 2,135,600 shares of outstanding common stock in the open market. The shares were repurchased at a weighted-average cost of $36.13 per share, including commissions, using cash on hand and borrowings under our revolving credit facility. We repurchased the shares under our existing Board-authorized stock repurchase program. As of the date of this filing, we are authorized to repurchase 3,072,184 additional shares under this program. Consistent with our view of treating large share repurchases as acquisitions, we have hedged production volumes equal to the amount of reserves represented by the repurchased shares in proportion to the total number of shares outstanding. Our management continues to evaluate opportunities to repurchase common stock as a part of our business plan.

On March 28, 2008, the Board of Directors approved an amended 2006 Equity Plan to, among other things, increase the number of shares of our common stock available for issuance under this plan and to specifically provide for the new PSP award program discussed in Note 5 under Part I, Item 1 of this report. This amended plan is subject to stockholder approval at our 2008 annual stockholders meeting to be held on May 21, 2008, and is more fully described in our proxy statement for that meeting.

Our net income for the quarter ended March 31, 2008, was $96.0 million or $1.50 per diluted share compared to 2007 results of $40.0 million or $0.63 per diluted share. This included the $56.0 million gain on sale of proved properties related to the divestiture of non-core properties that occurred on January 31, 2008. Production for the quarter was 28.3 BCFE which represents an 11 percent increase from the same period a year ago and a one percent decrease from the previous quarter. The sequential decrease in production is due to the divestiture of non-strategic assets mentioned above. Per MCFE lease operating expense decreased year over year $0.10 to $1.24 per MCFE as a result of a decrease in workover activity in the Rocky Mountain region. Additionally, the operating cost structure of the assets divested of in January 2008 was significantly higher than that of our retained property base. Per MCFE transportation decreased $0.03 to $0.14 per MCFE from the same period a year ago, which was driven by changes related to the sales measurement point in the Rocky Mountain region. Per MCFE production taxes increased $0.18 from the previous year's first quarter to $0.72 per MCFE due primarily to an increase in realized prices. DD&A, including ARO liability accretion expense, increased $0.56 to $2.48 per MCFE, which is a reflection of the higher cost of drilling and acquisitions over the last several years. These higher cost properties have become a larger part of our production base. 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, 2008, and the immediately preceding three quarters. Additional details of per MCFE costs are presented later in this section.

	For the Three Months Ended			
	March 31, 2008	December 31, 2007	September 30, 2007	June 30, 2007
	(In millions, except production sales data)			
Production (BCFE)	28.3	28.5	27.5	26.0
Oil and gas production revenue, excluding the effects of hedging	$ 310.4	$ 273.7	$ 228.5	$ 216.2
Lease operating expense	$ 35.1	$ 37.8	$ 36.9	$ 31.6
Transportation costs	$ 3.9	$ 3.8	$ 3.2	$ 4.2
Production taxes	$ 20.5	$ 19.1	$ 14.9	$ 14.5
DD&A	$ 70.4	$ 64.8	$ 59.1	$ 54.7
Exploration	$ 14.3	$ 16.0	$ 12.6	$ 11.1
General and administrative expense	$ 21.1	$ 15.1	$ 15.8	$ 16.3
Net income	$ 96.0	$ 32.8	$ 57.7	$ 59.2
Percentage change from previous quarter:				
Production (BCFE)	(1)% (1)	4%	6%	2%
Oil and gas production revenues, excluding the effects of hedging	13%	20%	6%	12%
Lease operating expense	(7)%	2%	17%	(7)%
Transportation costs	3%	19%	(24)%	(5)%
Production taxes	7%	28%	3%	6%
DD&A	8%	10%	8%	12%
Exploration	(11)%	27%	14%	(42)%
General and administrative expense	39%	(4)%	(3)%	26%
Net income	192%	(43)%	(3)%	48%

(1) 2% increase in production, net of divested properties

The table below details the regional breakdown of our first quarter 2008 production.

	ArkLaTex	Mid-Continent	Gulf Coast	Permian	Rocky Mountain	Total (1)
First Quarter 2008 Production:						
Oil (MBbl)	36.7	103.4	68.3	418.1	1,040.8	1,667.4
Gas (MMcf)	4,266.1	7,516.0	3,410.0	717.4	2,433.0	18,342.4
Equivalent (MMCFE)	4,486.4	8,136.2	3,820.0	3,226.2	8,678.0	28,346.8
Avg. Daily Equivalents (MMCFE/d)	49.3	89.4	42.0	35.5	95.4	311.5
Relative percentage	16%	29%	13%	11%	31%	100%

(1) Totals may not add due to rounding

Outlook for the Remainder of 2008

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 2008 budget. The last several years have seen a dramatic increase in the costs for drilling and completing oil and natural gas wells, although those increases have moderated somewhat in recent quarters. 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 contractors and suppliers. While we have not seen any signs that would indicate a change in the availability of rigs and services, strong commodity prices and a general increase in capital investment throughout the exploration and production segment cause us some concern about another round of cost increases for these services.

- Mid-Continent – Our plans for the remainder of 2008 in the Mid-Continent region include accelerating activity in our operated program in the Woodford Shale in the Arkoma Basin, and continuing our development and exploration activities in the Anadarko Basin. In our horizontal Woodford Shale program, we have seen improved results from our most recent wells in the program with industry leading drilling performance and a doubling of the estimated per well recovery. In the Anadarko Basin, we continue to be active in the Mayfield development area and our emphasis has shifted to the Granite Wash formation where a more limited and selective fracture stimulation technique has shown positive results. We also plan to continue working on our exploration program targeting the deeper formations of the Anadarko Basin.

- ArkLaTex – Activity in the ArkLaTex for 2008 is centered on programs that target the Cotton Valley and the James Lime formations. Throughout the region, we plan to operate two horizontal rigs for the remainder of the year and utilize several vertical rigs for certain programs. Our remaining program for the year in the Cotton Valley at Carthage includes six horizontal wells and 14 vertical wells. The ramp up in activity at Carthage is the result of a successful initial horizontal test well and bolt-on acquisition in the area. Also in the Cotton Valley, we continue to participate with our operating partners in the Elm Grove and Terryville programs. At Elm Grove, results from recent horizontal well tests have been very encouraging and we continue to monitor developments in the play to determine whether future development of the area should be done with horizontal drilling. In our operated James Lime program, we plan to continue drilling horizontal wells throughout the 75 mile long prospective trend we have identified.

- Permian Basin – Our programs in the Permian for the remainder of 2008 are focused primarily on two tight oil programs that target the Wolfberry section of the basin. In the operated Sweetie Peck program, we currently have five rigs running and anticipate drilling roughly 40 wells this year. We plan to drill wells in three 40-acre infill pilot areas to test the downspacing potential of the Wolfberry at Sweetie Peck this year, which have the potential to add meaningful reserves if successful. We expect approximately 25 wells to be drilled in the partner operated Halff East program this year.

  - Gulf Coast – Our 2008 activity in the Gulf Coast region will continue to focus on development of the Olmos shallow gas formation in the southern Maverick Basin of South Texas. The current emphasis is on a new well drilling program where we plan to operate two to three rigs in the play for the remainder of the year. We plan to continue evaluating our existing 3D seismic data over the properties, and are currently in the process of acquiring 71 square miles of additional 3D data to further our geologic understanding of the play and enhance our drilling results.

Also in the Maverick Basin, we recently entered into an arrangement to participate in a drill-to-earn program targeting the Pearsall and Eagleford shales. We will participate in four commitment wells during 2008 that, if successful, would expose St. Mary to additional significant acreage and reserve potential in the basin. While our operations in the Gulf Coast region have been focused onshore since our acquisitions of the Olmos properties in 2007, we will continue to have an operating footprint throughout the Gulf Coast, both onshore and offshore.

Non-strategic assets in South Louisiana are currently being marketed for sale, and if successful, we plan to utilize a tax-advantaged exchange structure to defer the anticipated gain and improve the economics of the sale.

- Rockies - Industry attention in the Williston Basin has been most recently focused on activity targeting the Bakken formation in North Dakota, east of the Nesson Anticline. Results in the play have been very encouraging and we have seen progression of the play move toward areas where we have acreage. We have recently permitted a number of wells in North Dakota and plan to reallocate capital within our existing budget to drill several horizontal wells targeting the Bakken formation this year. We have planned drilling activity in oil fields of the Powder River, Big Horn, and Wind River basins of Wyoming, and we continue to participate with operating partners in various projects throughout the Rocky Mountain region. Lastly, we continue to look at ways to optimize our Rocky Mountain portfolio. To that end, we are currently marketing for sale a package of primarily partner operated assets that are located in the Greater Green River Basin. If successful we plan to utilize a tax-advantaged exchange structure to defer the anticipated gain and improve the economics of the sale.

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 budget.

We continue to evaluate a large number of acquisition opportunities, both in our regional offices and at our corporate headquarters. We have a strong track record of identifying and executing 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 2008 we will continue to evaluate acquisition opportunities. We plan to add business development personnel and resources this year to pursue acquisitions in our current operating regions and to evaluate opportunities in other regions where we currently do not operate in order to leverage our existing technical knowledge to gain a foothold.

Performance Share Plan

During the fourth quarter of 2007 we decided to grant PSP awards in place of RSUs as the primary form of long-term equity incentive compensation for certain of our employees. Subject to stockholder approval, our Board of Directors approved an amendment and restatement of the 2006 Equity Incentive Compensation Plan on March 28, 2008. Pending stockholder approval we plan to grant the first award of performance shares on July 1, 2008. To cover the period from the beginning of the year through the date of the first performance share grant, we intend to make a transitional grant of RSUs on or about June 30, 2008. These RSUs will vest equally over three years beginning on December 15, 2008. PSPs are more common among our peer companies and will provide for target awards that are earned over a three-year performance period. We believe this new plan will provide more visible, more marketable, and more widely understood long-term incentive compensation. Target awards will be made at the beginning of the performance measurement period, and will have a back-end weighted vesting schedule and a multiplier factor based on total stockholder return. At the conclusion of the three-year measurement period, our TSR will be measured and compared against a pre-established performance index consisting of companies similar to us. Depending on the results of our TSR measurements compared to pre-established performance criteria, the actual award made to a participant will be between zero and two times the target award. There is no market or performance condition that results in an early payout determination, other than a change of control. This plan and the cash bonus plan will be widely utilized within the organization, ensuring that the performance of all eligible employees and executives is measured against consistent performance conditions. We do not anticipate there will be a significant increase in the number of individuals that will be designated to participate in and be eligible to receive awards under the amended 2006 Equity Plan as compared to prior plan years, although the number of shares of common stock that underlie such awards will depend on our performance.

Oil and Gas Production and Operating Margins

Our production in the first quarter of 2008 dipped slightly on a sequential basis to 28.3 BCFE as a result of properties that were divested on January 31, 2008. Adjusting for the volumes related to divested properties, production increased sequentially roughly two percent in the first quarter of 2008 as a result of the ongoing success of our drilling operations. Growth of production from quarter to quarter is impacted by the timing of drilling operations, completions, workovers, other operational issues, and acquisitions and divestitures as well as the overall production decline rate of our existing asset base. We believe that an important metric for measuring success of oil and gas production companies is the ability to grow reserves on an economic basis, which then provides a base for growth in production that will positively affect net asset value.

We continue to generate very strong operating margins, inclusive of general and administrative costs. Commodity prices in the first quarter of 2008, particularly for oil, were stronger than we had budgeted. With approximately 35 percent of our quarterly production being crude oil, we are benefiting from the significant run up in crude prices during 2008. Our operating margin for the first quarter of 2008 was $7.26 per MCFE, an increase of 26 percent from the same period a year ago.

Oil and Gas Prices

Results of our 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 that use first of the month index pricing, which means gas produced in that month is sold at the first of the month price regardless of the spot price on the day the gas is produced. Our crude oil is sold using contracts that pay us the average of the NYMEX West Texas Intermediate daily settlement or the average of the posted prices for the period in which the crude oil is produced, adjusted for market quality, transportation, and location differentials.

	For the Three Months Ended March 31, 2008	
Crude Oil (per Bbl) :		
NYMEX price	$	97.90
Net realized price	$	92.33
Net realized price, including the effects of hedging	$	76.24
Natural Gas (per Mcf) :		
NYMEX price	$	8.07
Net realized price	$	8.53
Net realized price, including the effects of hedging	$	8.69

The three-month average bid week natural gas price at Henry Hub increased by 15 percent and the average NYMEX WTI spot price increased eight percent between the fourth quarter of 2007 and first quarter of 2008. Year over year, the quarterly average bid week price for natural gas increased 16 percent. The 36-month forward strip price for natural gas at the beginning of 2008 was $8.66 per MMBtu. At the end of the first quarter of 2008, the 36-month forward contract had increased three percent to $8.89 per MMBtu.

Average quarterly crude oil prices increased eight percent from the fourth quarter of 2007 to the first quarter of 2008. In the fourth quarter of 2007, NYMEX WTI crude averaged $90.68 per barrel. In the first quarter of 2008, the price averaged $97.90 per barrel. The price of crude oil has increased significantly as the value of the U.S. dollar has declined against other major currencies in recent months. The 36-month forward strip price for crude oil at the end of 2007 was $88.08 per barrel. At the end of the first quarter of 2008, the 36-month forward contract had increased seven percent to $93.99 per barrel.

While changes in quoted NYMEX oil and Henry Hub natural gas prices are generally used as a basis for comparison within our industry, the price we receive for oil and natural gas is affected by quality, energy content, location, and transportation differentials for these products. We refer to this price as our realized price, which excludes the effects of hedging. Our realized price is further impacted by the result of our hedging contracts that have settled in the respective periods. We refer to this price as our net realized price. Our natural gas price realizations for the three months ended March 31, 2008, were improved by $2.9 million of realized hedging gains while our oil price realization was negatively impacted by $26.8 million of realized hedging losses. On a percentage basis, we have hedged more forecasted crude oil production than forecasted natural gas production. Furthermore, a significant portion of our anticipated crude oil production is hedged using swap prices that are below the current NYMEX strip prices, reducing the benefit that could be gained from the increase in oil prices.

Hedging Activities

We have a hedging program that is built primarily on hedging related to acquisitions in which we hedge the first two to five years of an acquisition's risked production. We also occasionally hedge a portion of our existing forecasted production. In October 2005 we hedged a significant portion of anticipated future production from our then existing producing properties using zero-cost collars. We also used swap contracts to hedge a portion of our specific forecasted natural gas production for 2006, 2007, and 2008 from properties we owned at the time. Taking into account all oil and gas production hedge contracts in place through April 25, 2008, we have hedged approximately 11 million Bbls of oil, 80 million MMBtu of natural gas, and 1 million Bbls of natural gas liquids through the year 2011. We believe we have established an economic base for our future operations. 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 or accrued for current year cash distributions under the Net Profits Plan are recorded as either general and administrative expense or exploration expense. These payments totaled $21.5 million for the three-month period ended March 31, 2008. These 2008 payments are higher than originally budgeted due to an increase in oil and gas commodity prices. The actual cash payments we make are dependent on actual production, realized prices, and operating and capital costs associated with the properties in each individual pool. Actual cash payments will be inherently different from the estimated long-term liability amount. Additional discussion is included in the analysis in the Comparison of Financial Results and Trends sections below. An increasing percentage of the costs associated with the payments for the Net Profits Plan are recorded as general and administrative expense compared to exploration expense. This is a function of the normal departure of employees who previously contributed to exploration efforts. We determined that all of the payments to individuals no longer employed by St. Mary should be recorded as general and administrative expense beginning in 2007.

With respect to the accounting estimate of the liability associated with future estimated payments from our Net Profits Plan, we have recorded $13.6 million of net expense for the three-month period ended March 31, 2008, thereby increasing the long-term liability associated with this item to $225.0 million. This increase is related to an increase in the estimated future net revenues used to calculate the liability driven by overall commodity price increases, the accretion of the discount used for the calculation, and the addition of the 2007 pool. We expect approximately $52 million of cash payments to be made or accrued in 2008, however it is not possible to predict this with certainty due to the impact that commodity prices and reserve estimates have on this estimate. The Company will not be adding new Net Profits Plan pools prospectively as this benefit has been replaced with a different long-term incentive compensation program, which is described in Note 5 of Part I, Item 1 of this report. Beginning in 2008 regular annual grants from the restricted stock units program and the Net Profits Plan are being replaced with grants of market-based performance shares under our 2006 Equity Plan. The Company will continue to make payments from the existing Net Profits Plan pools and will continue to make prospective adjustments to the long-term liability as necessary.

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. 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. Commodity prices impact the calculated cash flows during periods after payout and can dramatically affect the timing of the estimated date of payout of the individual pools. Our commodity price assumptions are currently determined from an average of actual prices realized over the prior 24 months together with adjusted NYMEX strip prices for the ensuing 12 months for a total of 36 months of data. This average is supplemented by including the effect of 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, 2008, would differ by approximately $21 million. A one percentage point decrease in the discount rate would result in an increase to the liability of approximately $14 million, while a one percentage point increase in the discount rate would result in a decrease to the liability of approximately $13 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.

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,		% Change Between Periods
	2008	2007	
Net production volumes			
Oil (MBbl)	1,667	1,709	(2)%
Natural gas (MMcf)	18,342	15,220	21%
MMCFE (6:1)	28,347	25,476	11%
Average daily production			
Oil (Bbl per day)	18,323	18,992	(4)%
Natural gas (Mcf per day)	201,565	169,112	19%
MCFE per day (6:1)	311,503	283,063	10%
Oil & gas production revenues(1)			
Oil production revenue	$ 127,127	$ 89,950	41%
Gas production revenue	159,355	122,440	30%
Total	$ 286,482	$ 212,390	35%
Oil & gas production expense			
Lease operating expenses	$ 35,105	$ 34,125	3%
Transportation costs	3,877	4,447	(13)%
Production taxes	20,494	13,748	49%
Total	$ 59,476	$ 52,320	14%
Average realized sales price(1)			
Oil (per Bbl)	$ 76.24	$ 52.62	45%
Natural gas (per Mcf)	$ 8.69	$ 8.04	8%
Per MCFE Data:			
Average net realized price(1)	$ 10.11	$ 8.34	21%
Lease operating expenses	(1.24)	(1.34)	(7)%
Transportation costs	(0.14)	(0.17)	(18)%
Production taxes	(0.72)	(0.54)	33%
General and administrative	(0.75)	(0.51)	47%
Operating profit	$ 7.26	$ 5.78	26%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$ 2.48	$ 1.92	29%

(1) Includes the effects of our hedging activities

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Financial Information (in thousands, except per share amounts):					
		March 31, 2008		December 31, 2007	% Change Between Periods
Working deficit	$	(160,584)	$	(92,604)	73%
Long-term debt	$	564,000	$	572,500	(1)%
Stockholders' equity	$	803,496	$	863,345	(7)%

		For the Three Months Ended March 31,			% Change Between Periods
		2008		2007	
Basic net income per common share	$	1.53	$	0.70	119%
Diluted net income per common share	$	1.50	$	0.63	138%
Basic weighted-average shares outstanding		62,861		57,011	10%
Diluted weighted-average shares outstanding		64,045		64,908	(1)%

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

Changes in production volumes, oil and gas production revenues, and costs generally reflect the cyclical and highly volatile nature of our industry. Production taxes are largely dependent on the prices we receive for oil and natural gas, which we are not able to predict. 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. We are anticipating oil and gas production expenses to be pressured upward throughout the remainder of 2008. Sustained strong commodity prices have the potential to increase the demand for services needed to produce oil and gas, particularly services with a significant labor component. Oil properties are generally more labor intensive and we have a significant amount of oil assets in our property mix. Costs related to fuel surcharges for trucking and disposal of saltwater are examples of areas in our business where we are seeing cost pressure. Production taxes are largely dependent on the prices we receive for oil and natural gas, which we are not able to predict. Depreciation, depletion, and amortization will generally be pressured upward as production related to higher cost properties acquired or developed in recent years become a larger percentage of our production mix. Our general and administrative expense will be impacted by cash payments made from the Net Profits Plan, which are impacted by realized prices. Additionally, competition for personnel in the exploration and production industry remains highly competitive and we have seen the cost to hire and retain personnel increase significantly.

We have in-the-money stock options and unvested RSUs that are considered potentially dilutive securities. These dilutive securities affect our earnings per share. Consequently, both basic and diluted earnings per share are presented in the table above. We account for our 3.50% Senior Convertible Notes under the treasury stock method. As a result, there is no impact on the diluted share calculation at the current time since the Company's stock price is not above the conversion price for the issuance. The 3.50% Senior Convertible Notes were issued April 4, 2007, and have not been dilutive at any point since their issuance. A detailed explanation is presented in Note 4 – Earnings Per Share, in 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, 2008, and 2007, reflect an increase in outstanding shares related to stock option exercises. We issued 27,376 and 64,880 shares of common stock during the three-month periods ended March 31, 2008, and 2007, respectively, as a result of stock option exercises. Additionally, during the first quarter of 2008, we issued 408,829 shares of common stock as a result of converting RSUs to common stock in accordance with the terms of the RSU grants and we repurchased 2.1 million shares of outstanding common stock. 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 project that our 2008 cash flows from operations will exceed our planned capital investment budget for exploration and development resulting in free cash flow that will be available for additional drilling opportunities, acquisitions, share repurchases, or repayment of debt. Accordingly, we do not expect to access the capital markets in 2008. On January 31, 2008, we closed on the sale of our previously announced divestiture of non-core oil and gas properties. Net proceeds from this transaction were $129.6 million. We anticipate that we will continue to evaluate our property base for divestiture candidates that we consider non-core.

Our primary sources of liquidity are the cash provided by operating activities, debt financing, sales of non-core properties, and access to capital markets. All of these sources can be impacted by the general condition of our industry and by significant fluctuations in oil and 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 realized revenues related to oil and gas sales through the use of derivative contracts. A decrease in oil and gas prices 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 have limited our industry’s access to the capital markets. The public debt markets for energy companies continue to be available to us, although they are less favorable than this time a year earlier. Credit spreads have increased materially, and the volume of transactions being placed in the market is down dramatically. The overall credit markets have seen a significant contraction as a result of credit tightening caused by the widely reported sub-prime and leveraged loan market issues. However, after a challenging first quarter, the public debt market has shown some improvements in recent weeks. Energy credit spreads have tightened since mid-March. Equity and convertible debt financings are still an available alternative and are somewhat favorable to energy companies that operate in the exploration and production sector of the oil and gas industry. This is a result of strong commodity prices and the general strength of the balance sheets of the companies in this industry as well as the historically low credit defaults of energy companies. We do not, however, anticipate any need to raise either public debt or equity financing in the foreseeable future. We intend to rely on our current revolving credit facility for borrowings. However, a significant transaction could necessitate the need to raise additional public debt or equity financing.

Our current credit facility

We have a five-year, $500 million revolving credit facility agreement with Wachovia Bank, Wells Fargo Bank, and nine other participating banks. As of the date of this filing our credit facility has a borrowing base of $1.4 billion. 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 are in compliance with all financial and non-financial covenants under this credit facility. As of April 25, 2008, we had $230.0 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 located in Note 7 - Long-term Debt of Part I, Item 1 of this report, and Alternate Base Rate loans accrue interest at Prime plus the

applicable margin from the utilization table. 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 a pledge of the common stock of any 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 $276.5 million as of March 31, 2008.

Our weighted-average interest rate paid in the first three months of 2008 was 5.2 percent and included fees paid on the unused portion of the credit facility's aggregate commitment amount and amortization of deferred financing costs associated with the 3.50% Senior Convertible Notes.

Uses of cash

We use cash for the acquisition, exploration, and development of oil and gas properties and for the payment of debt obligations, trade payables, income taxes, common stock repurchases, and stockholder dividends. In the first three months of 2008 we spent $161.3 million for capital development and $53.0 million for property acquisitions. These cash outflows were funded using cash inflows from operations and available borrowing capacity under our revolving credit facility.

Expenditures for exploration and development of oil and gas properties and acquisitions are the primary use of our capital resources. We anticipate spending approximately $661 million for development and exploration expenditures in 2008. The amount and allocation of future capital expenditures will depend upon a number of factors including the number and size of available economic acquisitions and drilling opportunities, our cash flows from operating and financing activities, and our ability to assimilate acquisitions. In addition, the impact of oil and gas prices on investment opportunities, the availability of capital and borrowing facilities, and the success of our development and exploratory activities could lead to changes in funding requirements for future development. We regularly review our capital investment budget to assess changes in current and projected cash flows, acquisition opportunities, debt requirements, and other factors.

During the first quarter of 2008, we purchased 2,135,600 shares of our common stock in the open market at a weighted-average price of $36.13, including commissions, for a total of $77.1 million. As of the date of this filing we have Board authorization to repurchase up to 3,072,184 additional shares of our common stock under our stock repurchase program. Shares may be repurchased from time to time in open market transactions or privately negotiated transactions subject to market conditions and other factors including certain provisions of our existing bank credit facility agreement, compliance with securities laws, and the terms and provisions of our stock repurchase program.

On January 31, 2008, we closed on the sale of our previously announced divestiture of non-core oil and gas properties. The proceeds from this transaction were used to repay debt under our revolving credit facility.

The following table presents amounts and percentage changes in cash flows between the three-month periods ended March 31, 2008, and 2007. 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,			
	2008	2007	Change	Percent Change
	(In thousands)			
Net cash provided by operating activities	$ 142,459	$ 126,075	$ 16,384	13%
Net cash used in investing activities	$ (93,944)	$ (136,029)	$ 42,085	(31)%
Net cash provided by (used in) financing activities	$ (84,514)	$ 13,223	$ (97,737)	(739)%

Analysis of cash flow changes between the three months ended March 31, 2008, and March 31, 2007

Operating activities. Cash received from oil and gas production revenue, net of the realized effects of hedging, increased $45.4 million to $262.1 million for the first quarter of 2008, compared with $216.7 million for the first quarter of 2007. Included in operating revenues as of March 31, 2008, is $23.9 million of net realized hedging losses. The 35 percent increase in oil and gas production revenue, net of the realized effects of hedging, was the result of an 11 percent increase in production and a 21 percent increase in our net realized price after hedging. Net cash payments made for income taxes in the first quarter of 2008 increased $3.9 million relative to the same period in 2007.

Investing activities. Total cash outflow for capital expenditures during the first quarter of 2008 for leasehold and drilling activities increased $26.1 million or 19 percent to $161.3 million. Proceeds from sale of oil and gas properties for the three-month period ended March 31, 2008, includes $130.4 million related to the Abraxas divestiture that was completed on January 31, 2008. Other cash flows from investing activities for the first quarter of 2008 include the refunding of a $10.0 million deposit related to this divestiture. Total cash outflow for the first quarter of 2008 relating to the acquisition of oil and gas properties increased $51.8 million to $53.0 million due to the acquisition of assets at Carthage Field.

Financing activities. Net repayments to our credit facility increased $24.5 million for the quarter ended March 31, 2008, compared with the same period in 2007. Cash flows from financing activities for the first quarter of 2007 included a $4.5 million repayment of a short-term note payable. We spent $77.2 million to repurchase shares of our common stock in the three-month period ended March 31, 2008.

Capital Expenditure Forecast

We use our capital resources primarily for the exploration and development of oil and gas properties and for acquisitions. Our 2008 capital expenditures forecast for drilling is approximately $661 million. This amount excludes non-cash asset retirement obligation capitalized assets. In the first quarter of 2008 we increased our capital investment budget in the Mid-Continent region from $135 million to $155 million in order to expand our 2008 operated horizontal Woodford shale program during the second half of the year. We also increased the capital investment budget in the Permian region to reflect increased leasing activity. Anticipated 2008 exploration and development expenditures for each of our regions are presented in the following table. The precise amount to be invested in the 2008 drilling program in each region cannot be predicted but the amounts presented below should be representative.

		Exploration and Development Expenditures (In millions)
ArkLaTex region	$	161
Mid-Continent region		155
Permian region		132
Rocky Mountain region		130
Gulf Coast region		83
	$	661

We regularly review our capital expenditure budget to reflect changes in current and projected cash flows, acquisition opportunities, drilling opportunities, debt requirements, regional cost inflation, and other factors. We project that our exploration and development budget will be within anticipated operating cash flows for 2008.

The following table sets forth certain historical information regarding the costs incurred by us in our oil and gas activities. Amounts presented include capitalized costs associated with asset retirement obligations.

	For the Three Months Ended March 31,			
		2008		2007
	(In thousands)			
Development costs	$	156,482	$	132,078
Exploration costs		32,619		37,147
Acquisitions:				
Proved		31,261		(443)
Unproved		22,196		(743)
Leasing activity		3,739		7,812
Total, including asset retirement obligation	$	246,297	$	175,851

Costs incurred for capital and exploration activities during the first three months of 2008 increased $70.4 million or 40 percent compared to the same quarter in 2007. Excluding acquisitions, our development and exploration spending increased $19.9 million compared to the same period in the prior year. This increase was a result of our drilling efforts progressing at a faster pace in the first quarter of 2008 compared with the first quarter of 2007. The $50.6 million increase in acquisitions is primarily attributable to the acquisition of oil and gas properties located in the Carthage Field. We have experienced significant capital cost inflation over the past three years. These cost increases explain a portion of the year-over-year increase in development and exploration costs. Costs to drill and complete wells have flattened in recent quarters as new rig and service capacity have entered the market, however strong commodity prices for a prolonged period could pressure these costs higher. Additionally, increases in steel prices that are being widely reported could also cause an increase in our costs.

We believe internally generated cash flows together with the cash available under our credit facility will be sufficient to fund our planned operating, drilling, and acquisition expenditures for the foreseeable future. The amount and allocation of future capital and exploration expenditures will depend upon a number of factors including the number and size of available economic acquisition and drilling opportunities, our cash flows from operating and financing activities, and our ability to assimilate acquisitions. In addition, the impact of oil and gas prices on investment opportunities, the availability of capital and borrowing facilities, and the success of our development and exploratory activities may lead to changes in funding requirements for future development.

Financing alternatives

The debt and equity capital markets continue to be available to energy companies that operate in the exploration and production segment of the oil and gas industry. This is a result of strong commodity prices and the general strength reflected in the balance sheets of the companies in this segment.

Commodity Price Risk and Interest Rate Risk

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

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, 2007.

Summary of Oil and Gas Production Hedges in Place

Our oil and natural gas derivative contracts include swap and costless 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 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. As of March 31, 2008, our hedged positions totaled approximately 11 million Bbls of crude oil, 77 million MMBtu of natural gas, and 1 million Bbls of natural gas liquids anticipated future production through 2011.

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 contracted 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 contracted floor price if the index price is below the floor price. We pay the difference between the contracted ceiling price and the index price only if the index price is above the contracted ceiling price. No amounts are paid or received if the index price is between the contracted floor and ceiling prices.

The following tables describe the volumes, average contract prices, and fair value of contracts we have in place as of March 31, 2008.

Oil Contracts

Oil Swaps			
Contract Period	Volumes (Bbl)	Weighted-Average Contract Price (Per Bbl)	Fair Value at March 31, 2008 Liability (In thousands)
Second quarter 2008			
NYMEX WTI	501,000	$ 71.75	$ 14,516
WCS	45,000	$ 53.69	1,164
Third quarter 2008			
NYMEX WTI	481,000	$ 71.91	13,071
WCS	45,000	$ 54.03	1,074
Fourth quarter 2008			
NYMEX WTI	451,000	$ 71.83	11,616
WCS	15,000	$ 50.42	396
2009			
NYMEX WTI	1,570,000	$ 71.64	36,464
2010			
NYMEX WTI	1,239,000	$ 66.47	31,422
2011			
NYMEX WTI	1,032,000	$ 65.36	25,605
All oil swap contracts	5,379,000		$ 135,328

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, 2008 Liability (In thousands)
Second quarter 2008	415,000	$ 50.00	$ 69.83	$ 12,825
Third quarter 2008	419,000	$ 50.00	$ 69.82	12,338
Fourth quarter 2008	419,000	$ 50.00	$ 69.82	11,879
2009	1,526,000	$ 50.00	$ 67.31	43,697
2010	1,367,500	$ 50.00	$ 64.91	39,102
2011	1,236,000	$ 50.00	$ 63.70	34,841
All oil collars	5,382,500			$ 154,682

Gas Contracts

Gas Swaps			
Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at March 31, 2008 Liability
	(MMBtu)	(per MMBtu)	(In thousands)
Second quarter 2008 -			
IF CIG	930,000	$ 7.12	$ 1,050
IF PEPL	1,420,000	$ 7.22	2,059
IF NGPL	240,000	$ 6.41	545
IF ANR OK	690,000	$ 7.64	802
IF EL PASO	260,000	$ 6.72	603
IF HSC	1,430,000	$ 7.88	2,633
NYMEX Henry Hub	180,000	$ 9.19	212
Third quarter 2008 -			
IF CIG	930,000	$ 6.91	1,386
IF PEPL	1,460,000	$ 7.48	2,269
IF NGPL	190,000	$ 6.69	457
IF ANR OK	640,000	$ 7.92	712
IF EL PASO	280,000	$ 7.16	659
IF HSC	1,460,000	$ 8.16	2,876
NYMEX Henry Hub	270,000	$ 9.38	244
Fourth quarter 2008 -			
IF CIG	930,000	$ 7.45	1,039
IF PEPL	1,490,000	$ 8.32	1,230
IF NGPL	160,000	$ 7.10	329
IF ANR OK	610,000	$ 8.22	548
IF EL PASO	300,000	$ 7.20	673
IF HSC	2,050,000	$ 8.71	3,025
NYMEX Henry Hub	270,000	$ 9.72	250
2009 -			
IF CIG	2,310,000	$ 7.72	278
IF PEPL	3,360,000	$ 8.06	2,234
IF NGPL	440,000	$ 7.11	677

IF ANR OK	1,340,000	$ 8.09	1,143
IF EL PASO	1,200,000	$ 7.11	1,931
IF HSC	10,000,000	$ 8.49	9,132
NYMEX Henry Hub	1,280,000	$ 9.03	854

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Gas Swaps (continued)

Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at March 31, 2008 Liability
	(MMBtu)	(per MMBtu)	(In thousands)
2010 -			
IF NGPL	60,000	$ 7.60	82
IF ANR OK	60,000	$ 7.98	63
IF EL PASO	1,090,000	$ 6.79	1,449
IF HSC	5,720,000	$ 8.32	2,983
NYMEX Henry Hub	1,440,000	$ 8.66	499
2011 -			
IF EL PASO	880,000	$ 6.34	1,294
IF HSC	320,000	$ 8.89	84
All gas swap contracts	45,690,000		$ 46,304

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Gas Collars				
Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at March 31, 2008 Liability
	(MMBtu)	(per MMBtu)	(per MMBtu)	(In thousands)
Second quarter 2008 -				
IF CIG	720,000	$ 5.60	$ 8.72	$ 161
IF PEPL	1,642,500	$ 6.28	$ 9.42	303
IF HSC	240,000	$ 6.57	$ 9.70	102
NYMEX Henry Hub	120,000	$ 7.00	$ 10.57	26
Third quarter 2008 -				
IF CIG	720,000	$ 5.60	$ 8.72	456
IF PEPL	1,657,500	$ 6.28	$ 9.42	1,080
IF HSC	240,000	$ 6.57	$ 9.70	267
NYMEX Henry Hub	120,000	$ 7.00	$ 10.57	94
Fourth quarter 2008 -				
IF CIG	720,000	$ 5.60	$ 8.72	704
IF PEPL	1,657,500	$ 6.28	$ 9.42	1,593
IF HSC	240,000	$ 6.57	$ 9.70	341
NYMEX Henry Hub	120,000	$ 7.00	$ 10.57	153
2009 -				
IF CIG	2,400,000	$ 4.75	$ 8.82	1,652
IF PEPL	5,510,000	$ 5.30	$ 9.25	5,145
IF HSC	840,000	$ 5.57	$ 9.49	1,068
NYMEX Henry Hub	360,000	$ 6.00	$ 10.35	392
2010 -				
IF CIG	2,040,000	$ 4.85	$ 7.08	1,334
IF PEPL	4,945,000	$ 5.31	$ 7.61	5,585
IF HSC	600,000	$ 5.57	$ 7.88	912
NYMEX Henry Hub	240,000	$ 6.00	$ 8.38	334
2011 -				
IF CIG	1,800,000	$ 5.00	$ 6.32	2,058
IF PEPL	4,225,000	$ 5.31	$ 6.51	6,511
IF HSC	480,000	$ 5.57	$ 6.77	889
NYMEX Henry Hub	120,000	$ 6.00	$ 7.25	202
All gas collars	31,757,500			$ 31,362

Natural Gas Liquid Contracts

Natural Gas Liquid Swaps*

Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at March 31, 2008 Liability
	(Bbls)	(per Bbl)	(In thousands)
Second quarter 2008	170,738	$ 39.53	$ 3,261
Third quarter 2008	194,694	$ 39.28	3,585
Fourth quarter 2008	219,004	$ 38.73	4,137
2009	638,159	$ 38.77	9,626
2010	8,021	$ 45.60	22
2011	1,129	$ 45.15	6
All natural gas liquid swaps	1,231,745		$ 20,637

*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%).

Hedge Contracts Entered into After March 31, 2008

The following table includes all hedges entered into subsequent to March 31, 2008, through April 25, 2008.

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(Bbl)	(Per Bbl)	(Per Bbl)
Second quarter 2008	83,000	$ 92.50	$ 114.50
Third quarter 2008	95,000	$ 92.50	$ 114.50
Fourth quarter 2008	100,000	$ 92.50	$ 114.50
All oil collars	278,000		

Gas Collars*

Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(MMBtu)	(per MMBtu)	(per MMBtu)

Third quarter 2008 -					
IF CenterPoint	1,000,000	$	8.75	$	10.20
Fourth quarter 2008 -					
IF CenterPoint	1,220,000	$	8.75	$	10.20
All gas collars	2,220,000				

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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 carry no off-balance sheet financing other than operating leases, nor do we have any unconsolidated subsidiaries.

Critical Accounting Policies and Estimates

We refer you to the corresponding section in Part II, Item 7 of our Annual Report on Form 10-K/A for the year ended December 31, 2007, and to the footnote disclosures included in Part I, Item 1 of this report.

Additional Comparative Data in Tabular Form:

	Change Between the Three Months Ended March 31, 2008 and 2007
Oil and gas production revenues	
Increase in oil and gas production revenues, net of hedging (In thousands)	$ 74,092

Components of Revenue Increases (Decreases):

Oil	
Realized price change per Bbl, including the effects of hedging	$ 23.62
Realized price percentage change	45%
Production change (MBbl)	(42)
Production percentage change	(2)%
Natural Gas	
Realized price change per Mcf, including the effects of hedging	$ 0.65
Realized price percentage change	8%
Production change (MMcf)	3,122
Production percentage change	21%

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

	For the Three Months Ended March 31,	
Revenue	2008	2007
Oil	44%	42%
Natural gas	56%	58%
Production		
Oil	35%	40%
Natural gas	65%	60%

Information Regarding the Components of Exploration Expense:

	For the Three Months Ended March 31,			
	2008		2007	
Summary of Exploration Expense	(In millions)			
Geological and geophysical expenses	$	1.8	$	2.6
Exploratory dry hole expense		0.7		9.6
Overhead and other expenses		11.8		6.8
Total	$	14.3	$	19.0

Information Regarding the Effects of Oil and Gas Hedging Activity:

	For the Three Months Ended March 31,			
	2008		2007	
Oil Hedging				
Percentage of oil production hedged		57%		65%
Oil volumes hedged (MBbl)		953		1,107
Increase (decrease) in oil revenue	$	(26.8 million)	$	28,000
Average realized oil price per Bbl before hedging	$	92.33	$	52.61
Average realized oil price per Bbl after hedging	$	76.24	$	52.62
Natural Gas Hedging				
Percentage of gas production hedged		39%		47%
Natural gas volumes hedged (MMBtu)	$	7.5 million	$	7.5 million
Increase in gas revenue	$	2.9 million	$	18.7 million
Average realized gas price per Mcf before hedging	$	8.53	$	6.82
Average realized gas price per Mcf after hedging	$	8.69	$	8.04

Comparison of Financial Results and Trends between the Quarters ended March 31, 2008 and 2007

Oil and gas production revenue. Average net daily production increased 10 percent to 311.5 MMCFE per day for the quarter ended March 31, 2008, compared with 283.1 MMCFE per day for the quarter ended March 31, 2007. The following table presents specific components that contributed to the change in revenue between the two quarters:

	Average Net Daily Production Added (Lost) (MMCFE)	Oil and Gas Revenue Added (Lost) (In millions)	Production Costs Added (Lost) (In millions)
Rockford acquisition and drilling	6.5	$ 5.7	$ 2.1
Williston Basin Middle Bakken Play	2.9	4.2	0.4
Elm Grove Field	12.4	9.4	0.7
James Lime formation	2.8	2.5	0.3
Anadarko Basin fields	15.7	12.1	1.0
Woodford shale formation – horizontal wells	8.6	5.3	0.8
Other wells completed in 2008 and 2007	34.8	33.0	2.9
Other acquisitions	2.0	1.7	0.6
Abraxas divestiture	(9.1)	(5.2)	(2.5)
Total	76.6	$ 68.7	$ 6.3

The revenue increases in this table also reflect the difference in oil and gas prices received between the comparable periods. The production volume 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.

Gain on sale of proved properties. We recorded a gain on sale of proved properties of $56.0 million during the first quarter of 2008 related to the Abraxas divestiture. The final gain on sale of proved properties will be adjusted for normal post-closing adjustments and is expected to be finalized during the second quarter of 2008.

Oil and gas production expense. Total production costs increased $7.2 million, or 14 percent, to $59.5 million for the first quarter of 2008 from $52.3 million in the comparable period of 2007. Total oil and gas production costs per MCFE increased $0.05 to $2.10 for 2008, compared with $2.05 for 2007. This increase is comprised of the following:

- A $0.03 decrease in overall transportation cost due to a decrease in the Rocky Mountain region resulting from changes related to the sales measurement point offset by a $0.04 increase in the Gulf Coast due to wells acquired in the Olmos formation during the fourth quarter of 2007, as well as newly drilled wells with higher transportation costs

- An $0.18 increase in production taxes on a per MCFE basis due to the increase in realized prices between periods, particularly in the oil-weighted Rocky Mountain and Permian regions

- Recurring LOE remained relatively flat

- A $0.10 overall decrease in LOE relating to workover charges, due to a decrease in workover expenses in the Rocky Mountain region.

Depletion, Depreciation, Amortization, and Asset Retirement Obligation Liability Accretion. DD&A increased $21.4 million or 44 percent to $70.4 million for the three-month period ended March 31, 2008, compared with $49.0 million for the same period in 2007. DD&A expense per MCFE increased 29 percent to $2.48 for the three-month period ended March 31, 2008, compared to $1.92 for the same period in 2007. This increase reflects overall upward cost pressure in the industry in recent years and specifically our acquisitions and drilling in 2008 and 2007 that added costs at a higher per unit rate. Additionally, this increase reflects the costs of production facilities in the offshore Gulf Coast that have increased significantly in recent years that are now impacting our DD&A rate as those projects begin production.

Exploration expense. Exploration expense decreased $4.7 million or 25 percent to $14.3 million for the three-month period ended March 31, 2008, compared with $19.0 million for the same period in 2007. This decrease is due to an $8.9 million decrease in exploratory dry hole expense related to two wells located in the Gulf Coast region and one in the Rockies region that were declared exploratory dry holes in the first quarter of 2007. The decrease in exploratory dry hole expense was offset by a $5.0 million increase in overhead and other expenses related to an increase in the size of our geological and exploration staff.

General and administrative. General and administrative expense increased $8.2 million or 64 percent to $21.1 million for the quarter ended March 31, 2008, compared with $12.9 million for the comparable period of 2007. G&A increased $0.24 to $0.75 per MCFE for the first quarter of 2008 compared to $0.51 per MCFE for the same three-month period in 2007.

A 20 percent increase in employee count has resulted in an increase in base employee compensation, including taxes and benefits, of approximately $3.4 million between the first quarter of 2008 and the first quarter of 2007. The $4.8 million increase in Net Profits Plan payments is the result of increased oil and gas commodity prices, which have triggered additional Net Profits Plan payouts to plan participants. As of the end of the first quarter of 2008, 17 of our 20 pools are currently in payout status. No additional pools are expected to reach payout in 2008.

Cash and RSU bonus expense is $1.3 million higher than in the prior year, which is primarily caused by the increase in employee count, as well as a slight increase in the accrued cash bonus. The above amounts combined with a net $2.9 million increase in other G&A expense, which includes charitable contributions and office supplies, were offset by a $2.7 million increase in the amount of general and administrative expense that was allocated to exploration expense, as well as a $1.5 million increase in COPAS overhead reimbursements. The increase in the amount of general and administrative expense is due to the increased allocation to G&A related to the aforementioned incentive plan as well as increases in the size of our technical exploration staff. COPAS overhead reimbursements from operations increased due to an increase in our operated well count resulting from our drilling and acquisition programs.

Change in Net Profits Plan Liability. For the quarter ended March 31, 2008, this non-cash expense was $13.6 million compared to $5.0 million for the same period in 2007. Oil and gas commodity price increases have triggered additional Net Profits Plan payouts and have increased the amounts payable to plan participants. This liability is a significant management estimate. Adjustments to the liability are subject to estimation and may change dramatically from period to period based on assumptions used for production rates, reserve quantities, commodity pricing, discount rates, tax rates, and production costs.

Income taxes. Income tax expense totaled $56.5 million for the first quarter of 2008 compared with $23.6 million for the first quarter of 2007 resulting in effective tax rates of 37.0 percent and 37.1 percent, respectively. The increase in income tax expense is a result of higher prices received for crude oil and natural gas, and significant net gains from property sales recorded in the first quarter of 2008. The small effective rate change from 2007 reflects changes in other permanent differences including differing estimated effects between years of the domestic production activities deduction and to a lesser extent, changes in the mix of the highest marginal state tax rates as a result of acquisition and drilling activity throughout 2007 and 2008. Our cash tax expenses increased for the first quarter of 2008 compared to the same period of 2007 as a result of higher net income from crude oil and natural gas sales partially offset by additional intangible drilling cost deductions from an increased level of capital spending during the first quarter of 2008. This trend is expected to continue throughout the remainder of 2008 based upon our current projected capital program and commodity price outlook.

Accounting Matters

We refer you to Note 11 – Fair Value Measurements and Note 14 – Recent Accounting Standards under Part I, Item 1 of this report for 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 we are in substantial compliance with environmental regulations and do not currently anticipate that material expenditures will be required in the 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
- 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 and performance to be materially different from any future results or performance expressed or implied by the forward-looking statements. These risks are described in the “Risk Factors” section of our 2007 Annual Report on Form 10-K/A, and include such factors as:

- The volatility and level of realized oil and natural gas prices
- Our ability to replace reserves and sustain production
- Unexpected drilling conditions and results
- Unsuccessful exploration and development drilling
- The availability 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 acquisitions and divestitures of oil and gas properties, including uncertainties in evaluating oil and natural gas reserves of acquired properties and associated potential liabilities
- 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
- The potential effects of increased levels of debt financing
- 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 be materially different from those expressed or implied in the forward-looking statements. Although we may from time to time voluntarily update our prior forward-looking statements, we disclaim any commitment to do so except as required by securities laws.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

ITEM 4. CONTROLS AND PROCEDURES

We maintain a system of disclosure controls and procedures that are designed to ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized, and reported within the time periods specified in the SEC’s rules and forms, and to ensure that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Acting Principal 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 Acting Principal 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 Acting Principal 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, the effectiveness of 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 materially adverse effect upon our financial condition, results of operations or cash flows.

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, 2007, in response to Item 1A of Part I of such Form 10-K/A.

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

(c) The following table provides information about purchases by the Company or any “affiliated purchaser” (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the fiscal quarter ended March 31, 2008, of shares of the Company’s common stock, which is the sole class of equity securities registered by the Company pursuant to Section 12 of the Exchange Act.

PURCHASES OF EQUITY SECURITIES BY ISSUER AND AFFILIATED PURCHASERS

Period	(a) Total Number of Shares Purchased (1) (2)	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Program	(d) Maximum Number of Shares that May Yet Be Purchased Under the Program (3)
01/01/08 – 01/31/08	658	$ 37.89	-0-	5,207,784
02/01/08 – 02/29/08	579,214	$ 37.44	458,400	4,749,384
03/01/08 – 03/31/08	1,729,429	$ 35.75	1,677,200	3,072,184
Total:	2,309,301	$ 36.18	2,135,600	3,072,184

(1) Includes a total of 3,000 shares purchased by Mark D. Mueller, St. Mary’s Senior Vice President and Regional Manager of the Rocky Mountain region, in open market transactions that were not made pursuant to our stock repurchase program.

(2) Includes 170,701 shares withheld (under the terms of grants under the 2006 Equity Incentive Compensation Plan) to offset tax withholding obligations that occur upon the delivery of outstanding shares underlying restricted stock units.

(3) In July 2006 the Company’s Board of Directors approved an increase in the number of shares that may be repurchased under the original August 1998 authorization to 6,000,000 as of the effective date of the resolution. Accordingly, as of the date of this filing, the Company has Board authorization to repurchase 3,072,184 shares of common stock on a prospective basis. The shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including certain provisions of St. Mary’s existing bank credit facility agreement and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flow, and borrowings under St. Mary’s bank credit facility. The stock repurchase program may be suspended or discontinued at any time.

The payment of dividends and stock repurchases are subject to covenants in our bank credit facility, including the requirement that we maintain certain levels of stockholders' equity and the limitation that does not allow our annual dividend rate to exceed $0.25 per share.

ITEM 5. OTHER INFORMATION

We have elected to include the following information in this Form 10-Q in lieu of reporting it in a separately filed Form 8-K. This information would otherwise have been reported in a Form 8-K under the heading "Item 5.02 Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers; Compensatory Arrangements of Certain Officers."

On April 30, 2008, our Board of Directors appointed Mark T. Solomon to serve as Acting Principal Financial Officer of the Company. It is currently expected that Mr. Solomon will serve in such position until a successor Chief Financial Officer of the Company is appointed by our Board of Directors. Mr. Solomon has served as Controller of the Company since January 2007 and he will continue to serve in that capacity. The biographical information relating to Mr. Solomon that was previously reported in Item 4A of our Annual Report on Form 10-K/A for the fiscal year ended December 31, 2007, is incorporated herein by reference. Mr. Solomon currently is not and has not previously been a party to any reportable related person transaction with the Company.

ITEM 6. EXHIBITS

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

Exhibit	Description
2.1	Ratification and Joinder Agreement dated January 31, 2008, to Purchase and Sale Agreement dated December 11, 2007, among St. Mary Land & Exploration Company, Ralph H. Smith, Trustee of the Ralph H. Smith Restated Revocable Trust Dated August 14, 1997, Kent J. Harrell, Trustee of the Kent J. Harrell Revocable Trust Dated January 19, 1995, Abraxas Operating, LLC, and Abraxas Petroleum Corporation (filed as Exhibit 2.2 to the registrant's Current Report on Form 8-K filed on February 1, 2008).
10.1*	Second Amended and Restated Credit Agreement dated April 10, 2008, among St. Mary Land & Exploration Company, Wachovia Bank, National Association as Administrative Agent, and the Lenders party thereto.
10.2	Cash Bonus Plan, as Amended on March 28, 2008 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on April 3, 2008).
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
31.2*	Certification of Acting Principal Financial Officer, pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
32.1**	Certification pursuant to U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes – Oxley Act of 2002

* Filed with this 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 2, 2008	By:/s/ ANTHONY J. BEST Anthony J. Best President and Chief Executive Officer
May 2, 2008	By:/s/ MARK T. SOLOMON Mark T. Solomon Controller and Acting Principal Financial Officer