ST MARY LAND & EXPLORATION CO
Form 10-Q
August 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 June 30, 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 company)	Smaller reporting 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 July 29, 2008, the registrant had 62,178,630 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	June 30, 2008	December 31, 2007
Current assets:		
Cash and cash equivalents	$ 36,919	$ 43,510
Short-term investments	1,000	1,173
Accounts receivable, net of allowance for doubtful accounts		
of $10,094 in 2008 and $152 in 2007	194,517	157,149
Hedge margin deposit	30,900	2,000
Refundable income taxes	9,854	933
Prepaid expenses and other	18,212	14,129
Accrued derivative asset	974	17,836
Deferred income taxes	143,148	33,211
Total current assets	435,524	269,941
Property and equipment (successful efforts method), at cost:		
Proved oil and gas properties	3,012,306	2,721,229
Less - accumulated depletion, depreciation, and amortization	(870,105)	(804,785)
Unproved oil and gas properties, net of impairment allowance		
of $9,587 in 2008 and $10,319 in 2007	159,057	134,386
Wells in progress	122,742	137,417
Oil and gas properties held for sale less accumulated depletion,		
depreciation, and amortization	1,665	76,921
Other property and equipment, net of accumulated depreciation		
of $12,466 in 2008 and $11,549 in 2007	10,175	9,230
	2,435,840	2,274,398
Noncurrent assets:		
Goodwill	9,452	9,452
Accrued derivative asset	2,208	5,483
Restricted cash subject to Section 1031 Exchange	25,266	-
Other noncurrent assets	12,548	12,406
Total noncurrent assets	49,474	27,341
Total Assets	$ 2,920,838	$ 2,571,680

LIABILITIES AND STOCKHOLDERS' EQUITY

Current liabilities:

Accounts payable and accrued expenses	$	302,872	$	254,918
Accrued derivative liability		382,552		97,627
Deposit associated with oil and gas properties held for sale		-		10,000
Total current liabilities		685,424		362,545
Noncurrent liabilities:				
Long-term credit facility		295,000		285,000
Senior convertible notes		287,500		287,500
Asset retirement obligation		103,741		96,432
Asset retirement obligation associated with oil and gas properties held for sale		36		8,744
Net Profits Plan liability		293,174		211,406
Deferred income taxes		186,590		257,603
Accrued derivative liability		520,573		190,262
Other noncurrent liabilities		8,417		8,843
Total noncurrent liabilities		1,695,031		1,345,790
Commitments and contingencies				
Stockholders' equity:				
Common stock, $0.01 par value: authorized - 200,000,000 shares;				
issued: 62,306,691 shares in 2008 and 64,010,832 shares in 2007;				
outstanding, net of treasury shares: 62,129,704 shares in 2008				
and 63,001,120 shares in 2007		623		640
Additional paid-in capital		86,930		170,070
Treasury stock, at cost: 176,987 shares in 2008 and 1,009,712 shares in 2007		(2,130)		(29,049)
Retained earnings		1,005,122		878,652
Accumulated other comprehensive loss		(550,162)		(156,968)
Total stockholders' equity		540,383		863,345
Total Liabilities and Stockholders' Equity	$	2,920,838	$	2,571,680

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

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2008	2007	2008	2007
Operating revenues and other income:				
Oil and gas production revenue	$ 399,961	$ 216,154	$ 710,393	$ 409,860
Realized oil and gas hedge gain (loss)	(68,396)	7,303	(92,346)	25,987
Marketed gas system and other operating revenue	22,339	23,697	41,942	32,313
Gain on sale of proved properties	3,038	-	59,055	-
Total operating revenues and other income	356,942	247,154	719,044	468,160
Operating expenses:				
Oil and gas production expense	73,625	50,328	133,101	102,648
Depletion, depreciation, amortization and asset retirement obligation liability accretion	76,354	54,657	146,708	103,616
Exploration	17,401	11,074	31,709	30,093
Impairment of proved properties	9,566	-	9,566	-
Abandonment and impairment of unproved properties	2,056	1,465	3,064	2,949
General and administrative	21,867	16,266	43,004	29,157
Bad debt expense	9,951	-	9,942	-
Change in Net Profits Plan liability	68,142	(1,160)	81,768	3,805
Marketed gas system and other operating expense	20,915	15,341	39,360	23,293
Unrealized derivative (gain) loss	(1,186)	1,200	5,231	5,104
Total operating expenses	298,691	149,171	503,453	300,665
Income from operations	58,251	97,983	215,591	167,495
Nonoperating income (expense):				
Interest income	59	154	156	257
Interest expense	(5,528)	(3,750)	(10,499)	(9,803)
Income before income taxes	52,782	94,387	205,248	157,949
Income tax expense	(19,232)	(35,152)	(75,702)	(58,764)
Net income	$ 33,550	$ 59,235	$ 129,546	$ 99,185
Basic weighted-average common shares outstanding	61,714	63,583	62,287	60,316

Diluted weighted-average common shares outstanding	62,749	65,120	63,404	65,015
Basic net income per common share	$ 0.54	$ 0.93	$ 2.08	$ 1.64
Diluted net income per common share	$ 0.53	$ 0.91	$ 2.04	$ 1.54

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (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,								
	302,370	3	(4,569)	-	-	-	-	(4,566)

net of shares used for tax withholdings								
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	-	-	-	-	-	129,546	-	129,546
Change in derivative instrument fair value	-	-	-	-	-	-	(451,893)	(451,893)
Reclassification to earnings	-	-	-	-	-	-	58,698	58,698
Minimum pension liability adjustment	-	-	-	-	-	-	1	1
Total comprehensive loss								(263,648)
Cash dividends, $ 0.05 per share	-	-	-	-	-	(3,076)	-	(3,076)
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 under Employee Stock Purchase Plan	17,626	-	579	-	-	-	-	579
Issuance of common stock upon settlement of RSUs following expiration of restriction period,	407,319	4	(6,398)	-	-	-	-	(6,394)

net of shares used for tax withholdings								
Sale of common stock, including income tax benefit of stock option exercises	812,376	8	19,662	-	-	-	-	19,670
Stock-based compensation expense	3,750	-	6,254	23,113	803	-	-	7,057
Balances, June 30, 2008	62,306,691	$ 623	$ 86,930	(176,987)	$ (2,130)	$ 1,005,122	$ (550,162)	$ 540,383

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, except share amounts)

	For the Six Months Ended June 30, 2008	2007
Cash flows from operating activities:		
Reconciliation of net income to net cash provided by operating activities:		
Net income	$ 129,546	$ 99,185
Adjustments to reconcile net income to net cash provided by operating activities:		
(Gain) loss on insurance settlement	960	(6,325)
Gain on sale of proved properties	(59,055)	-
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	146,708	103,616
Bad debt expense	9,942	-
Exploratory dry hole expense	6,606	11,220
Impairment of proved properties	9,566	-
Abandonment and impairment of unproved properties	3,064	2,949
Unrealized derivative loss	5,231	5,104
Change in Net Profits Plan liability	81,768	3,805
Stock-based compensation expense*	7,057	6,279
Deferred income taxes	55,996	52,457
Other	766	(2,696)
Changes in current assets and liabilities:		
Accounts receivable	(42,954)	12,507
Hedge margin deposit	(28,900)	-
Refundable income taxes	(8,921)	775
Prepaid expenses and other	(6,570)	(5,120)
Accounts payable and accrued expenses	14,850	2,327
Income tax benefit from the exercise of stock options	(9,565)	(3,762)
Net cash provided by operating activities	316,095	282,321
Cash flows from investing activities:		
Proceeds from insurance settlement	-	7,049
Proceeds from sale of oil and gas properties	154,597	324
Capital expenditures	(329,247)	(278,983)
Acquisition of oil and gas properties	(62,927)	(31,050)
Deposits to short-term investments	173	(1,138)
Receipts from short-term investments	-	1,450
Deposits to restricted cash	(25,266)	-
Other	(9,987)	17

Net cash used in investing activities		(272,657)		(302,331)
Cash flows from financing activities:				
Proceeds from credit facility		638,000		292,914
Repayment of credit facility		(628,000)		(530,914)
Repayment of short-term note payable		-		(4,469)
Income tax benefit from the exercise of stock options		9,565		3,762
Net proceeds from issuance of senior convertible debt		-		281,194
Proceeds from sale of common stock		10,684		5,378
Repurchase of common stock		(77,202)		-
Dividends paid		(3,076)		(3,140)
Net cash provided by (used in) financing activities		(50,029)		44,725
Net change in cash and cash equivalents		(6,591)		24,715
Cash and cash equivalents at beginning of period		43,510		1,464
Cash and cash equivalents at end of period	$	36,919	$	26,179

* 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 June 30, 2008, and 2007, respectively,
approximately $2.2 million and $1.9 million of stock-based compensation expense was included in exploration expense.
During the periods ended June 30, 2008, and 2007, respectively, approximately $4.9 million and $4.4 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 (Continued)

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

	For the Six Months Ended June 30, 2008	2007
	(in thousands)	
Cash paid for interest, inclusive of capitalized interest	$ 11,720	$ 11,405
Cash paid for income taxes	$ 18,687	$ 1,184

As of June 30, 2008, and 2007, $140.0 million and $110.6 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 May 2008 and 2007 the Company issued 23,113 and 26,292 shares, respectively, of common stock from treasury to its non-employee directors pursuant to the Company's 2006 Equity Incentive Compensation Plan. The Company recorded compensation expense related to these issuances of approximately $803,000 and $726,000 for the six-month periods ended June 30, 2008, and 2007, respectively.

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 February 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 were $141,900 and $45,012, respectively.

During the first six months of 2008 and 2007, the Company issued 427,607 and 89,232 restricted stock units to employees as equity-based compensation, respectively, pursuant to the Company's 2006 Equity Incentive Compensation Plan. The total value of the issuances were $23.3 million and $2.9 million, respectively.

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

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

June 30, 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 ("GAAP") 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 expected results for the full year.

Certain 2007 amounts in the unaudited condensed consolidated financial statements have been reclassified to correspond to the 2008 presentation. As a result of a change in circumstances in 2007, distributions being made and accrued for under the Net Profits Interest Bonus Plan (the "Net Profits Plan"), for former employees who were involved in geologic, geophysical or exploration activities are now classified and fully allocated to general and administrative expense rather than exploration expense. Distributions accrued or made to current employees engaged in geologic, geophysical, or exploration activities continue to be expensed as exploration expense. The entire impact for 2007 was recorded in the fourth quarter. The quarterly financial information presented for 2007 throughout the accompanying unaudited condensed 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.

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

Greater Green River Divestiture

In June 2008, the Company completed the divestiture of certain non-strategic oil and gas properties located in the Rocky Mountain region. The cash received at closing, net of commission costs, was $22.1 million. The final sales price is subject to normal post-closing adjustments and is expected to be finalized during the fourth quarter of 2008. The estimated gain on sale of proved properties related to the divestiture is approximately $1.0 million and may be impacted by the previously mentioned 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 ("EITF No. 03-13").

Carthage Acquisition

On March 21, 2008, the Company acquired oil and gas properties located primarily in the Carthage Field in Panola County, Texas for $49.2 million of cash. After normal purchase price adjustments, the Company allocated $29.1 million to proved oil and gas properties, $20.6 million to unproved oil and gas properties, and a net $215,000 to other liabilities. The Company also recorded $341,000 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. During the second quarter of 2008, the Company acquired additional interests in the majority of these properties for $8.0 million.

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 third quarter of 2008. The estimated gain on sale of proved properties related to the divestiture is approximately $59.8 million and may be impacted by the previously mentioned post-closing adjustments. The Company determined that these sales do not qualify for discontinued operations accounting under EITF No. 03-13.

Catarina Acquisition

On June 1, 2007, the Company acquired oil and gas properties located primarily in the Catarina project area in Webb County, Texas in exchange for $30.0 million of cash. After normal purchase price adjustments, the Company allocated $29.9 million to proved oil and gas properties, $535,000 to unproved oil and gas properties, and $215,000 to other assets. The Company also recorded $623,000 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.

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. The acquisition was funded with cash on hand and borrowings under the Company's existing credit facility. After normal purchase price adjustments, 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 hedged the equivalent of the first three years of risked natural gas production and the first two years of associated natural gas liquids risked 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. At June 30, 2008, SMA, LLC holds the assets pursuant to a qualified exchange accommodation agreement. From the date of closing of the Carthage acquisition on March 21, 2008 through the date of this report, the assets held by SMA, LLC, are leased by St. Mary under a triple net lease whereby St. Mary enjoys the benefits and risks of all revenues and costs attributed to the properties. The Carthage assets are managed by St. Mary under the terms of a management agreement with SMA, LLC. The second step of the like-kind exchange was partially completed in conjunction with the divestiture of certain non-core oil and gas properties discussed above under Greater Green River Divestiture. The funds from this transaction were deposited in an account owned by Comerica, Inc. as qualified intermediary in this transaction. As of June 30, 2008, this account had a balance of $25.3 million. St. Mary is evaluating other potential divestitures of non-core oil and gas properties in order to complete this Section 1031 exchange.

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 is recognizing all oil and gas reserves and production as well as all revenues and expenses attributed to the Carthage acquisition as of the March 21, 2008 acquisition date.

The Rockford acquisition of the Gold River assets described above 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 of the Rockford acquisition 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 above, St. Mary loaned an amount equal to the purchase price of the assets to SMLEA, LLC. Based on the provisions of FIN 46(R), the Company determined that SMLEA, LLC is a variable interest entity for which St. Mary is the primary

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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 June 30, 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 June 30, 2008, presents $1.7 million of assets held for sale, net of accumulated depletion, depreciation and amortization. Asset retirement obligation liabilities of $36,000 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 June 30, 2008. The Company determined that these sales do not qualify for discontinued operations accounting under EITF 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 six-month periods ended June 30, 2008, and 2007, respectively, included zero and approximately 3.1 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 for any reporting period that they have been outstanding and therefore do not impact the diluted earnings per share calculation for the three-month and six-month periods ended June 30, 2008, respectively.

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 or six-month periods ended June 30, 2008.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2008	2007	2008	2007
	(In thousands, except per share amounts)			
Net income	$ 33,550	$ 59,235	$ 129,546	$ 99,185
Adjustments to net income for dilution:				
Add: interest expense not incurred if 5.75% 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	$ 33,550	$ 59,235	$ 129,546	$ 99,984
Basic weighted-average common shares outstanding	61,714	63,583	62,287	60,316
Add: dilutive effect of stock options and unvested RSUs	1,035	1,537	1,117	1,559
Add: dilutive effect of 5.75% Convertible Notes using if-converted method	-	-	-	3,140
Diluted weighted-average common shares outstanding	62,749	65,120	63,404	65,015
Basic net income per common share	$ 0.54	$ 0.93	$ 2.08	$ 1.64
Diluted net income per common share	$ 0.53	$ 0.91	$ 2.04	$ 1.54

Note 5 – Compensation Plans

Cash Bonus Plan

The Company has a cash bonus plan, under which the Company has established a performance measure framework whereby selected employee participants can be awarded an annual cash bonus of up to a maximum ranging from 50 percent to 200 percent of their aggregate base salary. 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. 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. 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 is cash bonus expense related to the specific performance year of $2.7 million and $1.2 million for the three-month periods ended June 30, 2008 and 2007, respectively and total bonus expense for the six-month periods ended June 30, 2008 and 2007, was $4.5 million, and $2.5 million, respectively.

Equity Incentive Compensation Plan

There are several components to equity compensation that are described in this section. Varying types of equity awards have been granted by the Company in different periods.

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 June 30, 2008, 3.4 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”). An amendment and restatement of the 2006 Equity Plan was adopted by the Company’s Board of Directors on March 28, 2008, and approved by the Company’s stockholders at the Company’s 2008 annual stockholders’ meeting held on May 21, 2008. For any issuance of a direct share benefit such as an outright grant of common stock, a grant of a restricted share, or a restricted stock unit (“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 Awards (“PSA”) beginning in the third quarter of 2008 in place of grants of RSUs and the awarding of interests in 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. PSAs 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. PSAs will be granted under the 2006 Equity Plan as amended and restated as of March 28, 2008. The Company does have outstanding stock option grants under the Predecessor Plans and RSU awards under the Predecessor Plans and the 2006 Equity Plan. The following sections describe the details of RSU grants and stock options outstanding as of June 30, 2008.

Restricted Stock Incentive Program Under the Equity Incentive Compensation Plan

The Company historically had a long-term incentive program whereby grants of restricted stock or RSUs were awarded to eligible employees, consultants, and members of the Board of Directors. Restrictions and vesting periods for the awards were determined at the discretion of the Board of Directors and were 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 were determined annually based on a formula consistent with the cash bonus plan.

St. Mary issued 265,373 RSUs on June 30, 2008. Since the first PSA grant occurred on August 1, 2008, these RSUs were considered a transitional grant for the first six months of 2008. The total fair value associated with this issuance was $17.2 million in 2008 as measured on the grant date. The granted RSUs vest one third on December 15, 2008, one third on December 15, 2009, and one third on December 15, 2010.

St. Mary issued 158,744 RSUs on February 28, 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 first three anniversary dates of the grant.

St. Mary also issued 3,490 and 10,575 RSUs for various grants to certain employees during the six-month periods ended June 30, 2008, and 2007, respectively. These grants have various vesting schedules. The fair value of these awards is being recorded to compensation expense over the respective vesting periods using the same basic framework as described above.

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 shares are now issued without restriction upon vesting, rather than on the third anniversary of the award. This change was effected in 2007 within the safe harbor adoption provisions of the newly enacted U.S. Treasury regulations interpreting IRC laws governing deferred compensation. A mutual election of the employee and the Company was 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 is being 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 June 30, 2008, a total of 506,406 RSUs were outstanding, of which 8,227 were vested. Total RSU compensation expense for the three-month periods ended June 30, 2008 and 2007, was $3.0 million and $2.4 million, respectively, and the total compensation expense related to the RSUs for the six-month periods ended June 30, 2008, and 2007, was $6.0 million and $5.0 million, respectively. This amount includes $3.2 million of compensation expense related to the 2008 equity plan year for vesting of the value of RSUs granted June 30, 2008. As of June 30, 2008, there was $17.4 million of total unrecognized compensation expense related to unvested RSU awards. The unrecognized compensation expense is being amortized through 2011.

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 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.

On June 30, 2007, the Company converted 427,059 RSUs into common stock. 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 award agreements. As a result, the Company issued a net 302,370 shares of common stock associated with these grants. The remaining

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124,689 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 related to 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 six-month period ended June 30, 2007 were estimated using the following weighted-average assumptions:

	June 30, 2007
Risk free interest rate:	4.6%
Dividend yield:	0.3%
Volatility factor of the market price of the Company's common stock:	33.0%
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 could 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 February 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 $141,900 and $45,012, respectively.

A summary of the status and activity of non-vested RSUs for the six-month period ended June 30, 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	427,607	$	54.50
Vested	(196,245)	$	32.61
Forfeited	(22,568)	$	34.96
	498,179	$	51.01

Non-vested, at
June 30, 2008

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.

Total stock-based compensation expense related to stock options that were outstanding and unvested as of January 1, 2006, for the three-month periods ended June 30, 2008, and 2007, was $5,700 and $162,000, respectively, and the total stock-based compensation expense related to stock options for the six-month periods ended June 30, 2008, and 2007, was $17,000 and $382,000, respectively. 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 $9.6 million and $3.8 million of excess tax benefits for the six-month periods ended June 30, 2008, and 2007, respectively, as cash inflows from financing activities. Cash received from option exercises for the three-month periods ended June 30, 2008, and 2007, was $9.8 million and $4.1 million, respectively.

The following table summarizes the six-month activity for stock options outstanding as of June 30, 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	(812,376)	$ 12.44		
Forfeited	-	$ 0.00		
Outstanding, end of period	1,573,124	$ 12.71	4.16	$ 81,696
Vested, or expected to vest, end of period	1,573,124			$ 81,696
Exercisable, end of period	1,573,124	$ 12.71	4.16	$ 81,696

As of June 30, 2008, there was no 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 qualifies 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 1,582,185 shares are available for issuance as of June 30, 2008. The fair value of ESPP grants is measured at the date of grant using the Black-Scholes option-pricing model. There were 17,626 and 14,622 shares issued under the ESPP in the second quarter of 2008 and 2007, respectively. The Company expensed $90,000 and $63,000 based on the estimated fair value on the respective grant date for the three-month periods ended June 30, 2008, and 2007, respectively. The Company expensed $165,000 and $129,000 based on the estimated fair value on the respective grant date for the six-month periods ended June 30, 2008, and 2007, respectively.

Net Profits Plan

Under the Company's Net Profits Plan, all oil and gas wells that were completed or acquired during a year were 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 became 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 was in place from 1991 through 2007. 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, 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. 25 percent of the payments made under the Net Profits Plan were classified as exploration expense in the accompanying consolidated statements of operations for both the three-month periods ended June 30, 2008, and 2007. Of the payments made under the Net Profits Plan 24 percent and 21 percent were classified as exploration expense in the accompanying consolidated statements of operations for the six-month periods June 30, 2008, and 2007, respectively. 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 ongoing exploration support.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2008	2007	2008	2007
	(In thousands)			
General and administrative expense	$ 51,406	$ (870)	$ 62,313	$ 3,024
Exploration expense	16,736	(290)	19,455	781
Total	$ 68,142	$ (1,160)	$ 81,768	$ 3,805

Note 6 – Income Taxes

Income tax expense for the three-month and six-month periods ended June 30, 2008, and 2007, differs from the amount that would be provided by applying the statutory U.S. federal income tax rate to income before income taxes as a result of the estimated effect of the domestic production activities deduction, percentage depletion, the effect of state income taxes, and other permanent differences.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2008	2007	2008	2007
	(In thousands)		(In thousands)	
Current portion of income tax expense:				
Federal	$ 12,859	$ 3,200	$ 18,740	$ 4,982
State	466	732	966	1,325
Deferred portion of income tax expense:	5,907	31,220	55,996	52,457
Total income tax expense	$ 19,232	$ 35,152	$ 75,702	$ 58,764
Effective tax rates	36.4%	37.3%	36.9%	37.2%

A change in the Company's tax rates between reported periods will generally reflect differences in its estimated highest marginal state tax rate due to changes in the composition of income between state tax jurisdictions resulting from Company activities. Changes in the effects of estimates for the domestic production activities deduction, percentage depletion, and the possible impact of permanent differences related to state income tax calculations caused in part by fluctuating commodity prices can also cause the rates to vary.

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.

In 2007, the Company received a refund of income tax and interest of $3.1 million 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. On April 24, 2008 the Internal Revenue Service initiated an audit of the Company's 2005 tax year.

The Company adopted the provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," on January 1, 2007. There was no financial statement adjustment required as a result of adoption. At adoption, the Company had a long-term liability for unrecognized tax benefit of $1.0 million and an accumulated interest liability of $92,000. The entire amount of unrecognized tax benefit would affect the Company's effective tax rate if recognized. Interest expense associated with income tax is recorded as interest expense in the 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 must comply with certain financial covenants under the terms of its credit facility agreement, including the limitation of the Company's annual dividend rate to no more than $0.25 per share. The Company is in compliance with all financial and non-financial covenants under the credit facility. Interest and commitment fees are accrued based on the borrowing base utilization percentage table below. Eurodollar 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%
Eurodollar 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 $295.0 million and $265.0 million outstanding under its revolving credit agreement as of June 30, 2008, and July 29, 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 converted prior to maturity, 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.

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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 as provided by 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 $397 million as of June 30, 2008.

Weighted-Average Interest Rate Paid and Capitalized Interest Costs

The weighted-average interest rates paid for the three-month periods ended June 30, 2008 and 2007 were 4.6 percent and 5.6 percent, respectively, including commitment fees paid on the unused portion of the

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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 weighted-average interest rates paid for the six-month periods ended June 30, 2008, and 2007, were 4.9 percent and 6.3 percent, respectively. The outstanding loan balance as of June 30, 2008 increased in comparison to 2007, while the three-month and six-month period rates associated with the balances decreased. The decrease is attributable to significantly lower LIBOR and Prime rates for the specified periods in 2008 and 2007. Capitalized interest costs for the Company for the three-month periods ended June 30, 2008 and 2007, were $851,000 and $1.2 million, respectively. Additionally, capitalized interest costs for the six-month periods ended June 30, 2008, and 2007, were $2.1 million and $2.6 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. Refer to the tables under Summary of Oil and Gas Production Hedges in Place in Part I, Item 2, Management's Discussion and Analysis of Financial Condition and Results of Operations, for details regarding the Company's hedged volumes and associated prices. As of June 30, 2008, the Company has hedge contracts in place through 2011 for a total of approximately 10 million Bbls of anticipated crude oil production, 73 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 June 30, 2008, all oil, natural gas, and natural gas liquid derivative instruments qualified as cash flow hedges for accounting purposes. The Company anticipates that all forecasted transactions will occur by the end of their originally specified periods. All contracts are entered into for other than trading purposes.

The fair value of oil and natural gas derivative contracts designated and qualifying as cash flow hedges under SFAS No. 133 was a net liability balance of $899.6 million at June 30, 2008. The Company realized a net loss of $68.4 million and a net gain of $7.3 million from its oil and gas derivative contracts for the three-month periods ended June 30, 2008, and 2007, respectively.

At June 30, 2008 and December 31, 2007 the Company had $30.9 million and $2.0 million, respectively, on deposit with a hedge counterparty. Generally, the Company's hedge liability to its counterparties is secured under the terms of the Company's credit facility agreement. One hedge counterparty is not a participant in the Company's credit facility agreement and therefore requires a dollar for dollar margin to be posted for mark-to-market liabilities which exceed a certain limit.

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 June 30, 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 $235.1 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 June 30, 2008, and 2007, includes a net gain of $1.2 million and a net loss of $1.2 million, respectively, from ineffectiveness related to oil and natural gas derivative contracts. Unrealized derivative loss for both the six-month periods ended June 30, 2008, and 2007, includes net losses of $5.2 million 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:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2008	2007	2008	2007
	(In thousands)		(In thousands)	
Derivative contract settlements included in oil and gas hedge gain (loss)	$ (68,396)	$ 7,303	$ (92,346)	$ 25,987
Ineffective portion of hedges qualifying for hedge accounting included in derivative gain (loss)	1,186	(1,200)	(5,231)	(5,225)
Non-qualified derivative contracts included in derivative gain (loss)	-	-	-	121
Interest rate derivative contract settlements included in interest expense	(418)	-	(540)	(283)
Total gain (loss)	$ (67,628)	$ 6,103	$ (98,117)	$ 20,600

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. The Company recorded a net derivative loss in interest expense of $283,000 for the six-month period ended June 30, 2007. There was no net derivative loss recorded in interest expense for the three-month period ended June 30, 2007.

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 pays a fixed rate of 4.90 percent and is 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 sheet at June 30, 2008, was $378,000. 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 net derivative losses in interest expense of $418,000 and $540,000 in the accompanying consolidated statements of operations

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for the three-month and six-month periods ended June 30, 2008, respectively, related to this interest rate derivative contract.

The contingent interest provision of the 3.50% Senior Convertible Notes is a derivative instrument. As of June 30, 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 June 30,		For the Six Months Ended June 30,	
	2008	2007	2008	2007
	(In thousands)		(In thousands)	
Service cost	$ 460	$ 477	$ 920	$ 955
Interest cost	222	199	443	397
Expected return on plan assets	(168)	(135)	(335)	(270)
Amortization of net actuarial loss	40	54	80	109
Net periodic benefit cost	$ 554	$ 595	$ 1,108	$ 1,191

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

The Company has contributed $2.4 million to the Qualified Pension Plan during the first half of 2008. Presently, the Company believes it will contribute an additional $400,000 to the Nonqualified Pension Plan during the remainder of the year.

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 June 30,		For the Six Months Ended June 30,	
	2008	2007	2008	2007
	(In thousands)		(In thousands)	
Beginning asset retirement obligation	$ 103,981	$ 86,519	$ 108,284	$ 77,242
Liabilities incurred	2,060	3,147	6,089	4,741
Liabilities settled	(1,873)	(510)	(12,470)	(1,298)
Accretion expense	1,718	1,398	3,383	2,750
Revision to estimated cash flow	600	-	1,200	7,119
Ending asset retirement obligation	$ 106,486	$ 90,554	$ 106,486	$ 90,554

Accounts payable and accrued expenses contain $2.7 million and $9.3 million related to the Company's asset retirement obligation liability for the six-month periods ended June 30, 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 third quarter of 2008. 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.

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The following is a listing of the Company’s liabilities required to be measured at fair value on a recurring basis and where they are classified within the hierarchy as of June 30, 2008:

	Level 1	Level 2	Level 3
		(In thousands)	
Liabilities			
Net accrued derivative liability	$ -	$ 899,943	$ -
Net Profits Plan	-	-	293,174
Total	$ -	$ 899,943	$ 293,174

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

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 the Company evaluates 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. The Company is currently in a net liability position with all of its 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 lower the commodity price risk associated with an acquisition 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 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 June 30, 2008, would differ by approximately $27 million. A one percentage point decrease in the discount rate would result in an increase to the liability of approximately $20 million, while a one percentage point increase in the discount rate would result in a decrease to the liability of approximately $18 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 are 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 liability. 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 three-month and six-month periods ended June 30, 2008:

	For the Three Months Ended June 30, 2008	For the Six Months Ended June 30, 2008
	(In thousands)	
Beginning balance	$ 225,032	$ 211,406
Net increase (decrease) in liability (a)	82,127	117,283
Net settlements (a) (b)	(13,985)	(35,515)
Transfers in (out) of Level 3	-	-
Ending balance	$ 293,174	$ 293,174

(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.

Refer to 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. Additionally, refer to Note 7 – Long-term Debt for the disclosure of the June 30, 2008, fair value of the 3.50% Senior Convertible Notes Due 2027.

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 three-month period ended June 30, 2008.

St. Mary did not repurchase any shares of common stock under the program during the three or six month periods ended June 30, 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 second quarter of 2008, bringing the total plug and abandonment costs accrued for the platform to $13.3 million. As of June 30, 2008, the Company has spent $10.6 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's plug and abandonment efforts are substantially complete as of the date of this filing, and the Company expects adjustments to the gain to be completed by the third 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, electing 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 the Company's 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. Refer to 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 consolidated financial statements.

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, the 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 consolidated financial statements.

In May 2008, the FASB issued FASB Staff Position APB 14-1, "Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement)" ("FSP APB 14-1"), which establishes bifurcation accounting for convertible debt instruments that may be settled in cash upon conversion. FSP APB 14-1 states that such instruments should be valued without the conversion feature and should be classified as debt and that the remaining proceeds should be recorded as equity to represent the cash settlement option. For instruments within the scope of FSP APB 14-1 debt discounts shall be amortized over the expected life of a similar liability that does not have an associated equity component. Amortization of the debt discount will result in increased interest expense in the statement of operations. FSP APB 14-1 will also yield lower earnings per share dilution than typical convertible bonds. FSP APB 14-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008. The Company will be required to adopt FSP APB 14-1 beginning with its 2009 fiscal year, and early adoption is not permitted. FSP APB 14-1 must be applied retrospectively to all periods presented for any instrument within the scope of FSP APB 14-1 that was outstanding during any of the periods presented. FSP APB 14-1changes the accounting treatment for the Company's 3.50% Senior Convertible Notes, and will increase the Company's non-cash interest expense for its past and future reporting periods. In addition, it will reduce the Company's long-term debt and increase the Company's stockholders' equity for the past reporting periods. The Company is currently evaluating the full impact of FSP APB 14-1 on its consolidated financial statements.

In May 2008, the FASB issued SFAS No. 162, "The Hierarchy of Generally Accepted Accounting Principles" ("SFAS No. 162"), which identifies a consistent framework for selecting accounting principles to be used in preparing financial statements for nongovernmental entities that are

presented in conformity with United States GAAP. The current GAAP hierarchy was criticized due to its complexity, ranking position of FASB Statements of Financial Accounting Concepts and the fact that it is directed at auditors rather than entities. SFAS No. 162 will be effective 60 days following the Securities and Exchange Commission's approval of the Public Company Accounting Oversight Board amendments to AU Section 411, "The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles." The FASB does not expect that SFAS No. 162 will have a change in current practice, and the Company does not believe that SFAS No. 162 will have an impact on its financial position, results of operations or cash flows.

Note 15 – Subsequent Events

On July 22, 2008, SemGroup, L.P. and certain of its North American susidiaries (collectively referred to herein as "SemGroup"), filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware. Certain SemGroup entities purchase a portion of the Company's crude oil production. As a result of the SemGroup bankruptcy filings, the Company increased its allowance for doubtful accounts and bad debt expense by approximately $9.9 million for June 2008 production sold to SemGroup that was recorded in the six-month period ended June 30, 2008. St. Mary believes that it has an additional $6.8 million of potential exposure with SemGroup for a portion of production in July 2008. The Company is monitoring the bankruptcy proceedings closely to determine and pursue the best course of action that would result in the collection of the amounts owed and the continuation of crude oil sales in the producing regions affected. This matter does not have a material adverse effect on the Company's liquidity or overall financial position.

The Company granted its first awards of PSAs on August 1, 2008. A total of 465,751 PSAs were granted. The PSAs represent the right to receive, upon settlement of the PSAs after the completion of the three-year performance period ending June 30, 2011, a number of shares of the Company's common stock that may be from zero to two times the number of PSAs granted on the award date, depending on the extent to which the Company's performance criteria have been achieved and the extent to which the PSAs have vested. The performance criteria for the PSAs are based on a combination of the Company's cumulative total shareholder return ("TSR") for the performance period and the relative measure of the Company's TSR compared with the cumulative TSR of certain peer companies for the performance period. The PSAs will vest 1/7th on August 1, 2009, 2/7ths on August 1, 2010 and 4/7ths on August 1, 2011. Refer to Note 5 – Compensation Plans for additional information regarding the Company's Equity Incentive Compensation Plans.

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

This discussion contains forward-looking statements. 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 located 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
- East Texas and North Louisiana
- 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 also 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.

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 quality, transportation, and location differentials.

	For the Three Months Ended June 30,	
	2008	2007
Crude Oil (per Bbl) :		
NYMEX price	$ 123.98	$ 65.03
Realized price, before the effects of hedging	$ 120.20	$ 61.11
Net realized price, including the effects of hedging	$ 88.40	$ 59.97
Natural Gas (per Mcf) :		
NYMEX price	$ 10.80	$ 7.56
Realized price, before the effects of hedging	$ 10.83	$ 7.09
Net realized price, including the effects of hedging	$ 9.97	$ 7.68

Average quarterly NYMEX crude oil prices increased 27 percent from the first quarter of 2008 to the second quarter of 2008. In the first quarter of 2008, the price averaged $97.90 per barrel. In the second quarter of 2008, NYMEX crude averaged $123.98 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 and due to global supply and demand dynamics. The 36-month forward strip price for crude oil at the end of the first quarter of 2008 was $96.14 per barrel. At the end of the second quarter of 2008, the 36-month forward contract had increased 45 percent to $139.34 per barrel. By July 29, 2008, the 36-month forward strip price had declined 12 percent to $122.42 per barrel.

The average of the bid week prices for natural gas prices increased 34 percent from the first quarter of 2008 to the second quarter of 2008. In the first quarter of 2008, the price averaged $8.07 per Mcf. In the second quarter of 2008, the price averaged $10.80 per Mcf. The 36-month forward strip price for natural gas at the end of the first quarter of 2008 was $9.59 per MMBtu. At the end of the second quarter of 2008, the 36-month forward contract had increased 24 percent to $11.91 per MMBtu. As of July 29, 2008, the 36-month forward strip price had declined 21 percent to $9.43 per MMBtu.

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 net natural gas price realizations for the three months ended June 30, 2008, were negatively impacted by $16.1 million of realized hedging losses and our net oil price realization was negatively impacted by $52.3 million of realized hedging losses. For the six months ended June 30, 2008, our natural gas price realizations were negatively impacted by $13.2 million of realized hedging losses and our oil price realization was negatively impacted by $79.1 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. Taking into account all oil and gas production hedge contracts in place through July 29, 2008, we have hedged approximately 10 million Bbls of oil, 73 million MMBtu of natural gas, and one million Bbls of natural gas liquids for anticipated future production through the year 2011. Refer to 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 $14.0 million and $35.5 million for the three-month and six-month periods ended June 30, 2008. These amounts are higher than originally budgeted due to the increase in oil and gas commodity prices discussed above. 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 $81.8 million of net expense for the six-month period ended June 30, 2008, which increased the long-term liability associated with this item to $293.2 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 $60 million of cash payments to be made or accrued during 2008, however it is not possible to predict this with a high degree of certainty due to the impact commodity prices and reserve estimates have on this liability. 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 NPP 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 June 30, 2008, would differ by approximately $27 million. A one percentage point decrease in the discount rate would result in an increase to the liability of approximately $20 million, while a one percentage point increase in the discount rate would result in a decrease to the liability of approximately $18 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.

Performance Share Plan

During the fourth quarter of 2007 we decided to grant PSAs in place of RSUs as the primary form of long-term equity incentive compensation for certain employees. Our Board of Directors approved an amendment and restatement of the 2006 Equity Incentive Compensation Plan on March 28, 2008, and the amended plan was approved by stockholders at our annual stockholders meeting on May 21, 2008. We granted the first award of performance shares on August 1, 2008. PSAs 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 long-term incentive plan will be more transparent and more widely understood by our employees and our stockholders. 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 performance 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. The only market or performance condition that results in an early payout determination is 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.

Second Quarter 2008 Highlights

Greater Green River Divestiture

In June 2008, the Company completed the divestiture of certain non-strategic oil and gas properties located in the Rocky Mountain region. The cash received at closing, net of commission costs was $22.1 million. The final sales price is subject to normal post-closing adjustments and is expected to be finalized during the fourth quarter of 2008. The estimated gain on sale of proved properties related to the divestiture is approximately $2.1 million and may be impacted by the previously mentioned post-closing adjustments. The Company determined that these sales do not qualify for discontinued operations accounting under EITF No. 03-13.

Our net income for the quarter ended June 30, 2008, was $33.6 million or $0.53 per diluted share compared to 2007 results of $59.2 million or $0.91 per diluted share. We discuss these financial results and trends in more detail below.

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

	ArkLaTex	Mid-Continent	Gulf Coast	Permian	Rocky Mountain	Total (1)
Second Quarter 2008 Production:						
Oil (MBbl)	35.7	85.3	74.8	423.7	1,025.0	1,644.5
Gas (MMcf)	4,073.7	7,271.7	3,877.0	944.0	2,517.9	18,684.3
Equivalent (MMCFE)	4,287.8	7,783.4	4,326.0	3,486.1	8,667.9	28,551.1
Avg. Daily Equivalents (MMCFE/per day)	47.1	85.5	47.5	38.3	95.3	313.7
Relative percentage	15%	27%	15%	12%	30%	100%

(1) Totals may not add due to rounding

The table below provides information regarding selected production and financial information for the quarter ended June 30, 2008, and the three most recent quarters. Additional details of per MCFE costs are presented later in this section.

	For the Three Months Ended			
	June 30, 2008	March 31, 2008	December 31, 2007	September 30, 2007
	(In millions, except production sales data)			
Production (BCFE)	28.6	28.3	28.5	27.5
Oil and gas production revenue, excluding the effects of hedging	$ 400.0	$ 310.4	$ 273.7	$ 228.5
Lease operating expense	$ 41.0	$ 35.1	$ 37.8	$ 36.9
Transportation costs	$ 5.6	$ 3.9	$ 3.8	$ 3.2
Production taxes	$ 27.0	$ 20.5	$ 19.1	$ 14.9
DD&A	$ 76.4	$ 70.4	$ 64.8	$ 59.1
Exploration	$ 17.4	$ 14.3	$ 16.0	$ 12.6
General and administrative expense	$ 21.9	$ 21.1	$ 15.1	$ 15.8
Net income	$ 33.6	$ 96.0	$ 32.8	$ 57.7
Percent change from previous quarter:				
Production (BCFE)	1%	(1)%	4%	6%
Oil and gas production revenues, excluding the effects of hedging	29%	13%	20%	6%
Lease operating expense	17%	(7)%	2%	17%
Transportation costs	44%	3%	19%	(24)%
Production taxes	32%	7%	28%	3%
DD&A	9%	8%	10%	8%
Exploration	22%	(11)%	27%	14%
General and administrative expense	4%	39%	(4)%	(30)%
Net income	(65)%	192%	(43)%	(3)%

First Six Months 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. During the first half of 2008 we recorded a $59.1 million gain on sale of proved properties, which included the gain from the Abraxas and Greater Green River divestitures, as well as some other non-significant divestitures.

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 $49.2 million, net of customary closing adjustments. The acquisition was funded with cash on hand and borrowings under our existing revolving credit facility. At the acquisition date, we estimated proved reserves associated with this acquisition of approximately 25 BCFE. This acquisition was structured to qualify as the first step of a reverse like-kind exchange. The second step of the like-kind exchange was partially completed in conjunction with the divestiture of certain non-core oil and gas properties located in the Greater Green River Basin.

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.

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.

Our net income for the six months ended June 30, 2008, was $129.5 million or $2.04 per diluted share compared to 2007 results of $99.2 million or $1.54 per diluted share. We discuss these financial results and trends in more detail below.

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

	ArkLaTex	Mid-Continent	Gulf Coast	Permian	Rocky Mountain	Total (1)
First Half 2008 Production:						
Oil (MBbl)	72.4	188.6	143.2	841.8	2,065.8	3,311.9
Gas (MMcf)	8,339.7	14,787.7	7,287.0	1,661.4	4,950.9	37,026.7
Equivalent (MMCFE)	8,774.2	15,919.6	8,146.0	6,712.3	17,345.8	56,897.9
Avg. Daily Equivalents (MMCFE/per day)	48.2	87.5	44.8	36.9	95.3	312.6
Relative percentage	15%	28%	14%	12%	30%	100%

(1) Totals may not add due to rounding

Events Subsequent to June 30, 2008

On August 4, 2008, we announced that Wade Pursell was hired as Executive Vice President and Chief Financial Officer. He is expected to begin employment with us on September 8, 2008. Refer to Item 5 – Other Information in Part II, Item 5 of this report for additional information regarding Mr. Pursell.

On July 22, 2008, SemGroup, a purchaser of our crude oil, filed for Chapter 11 bankruptcy protection. As a result, we increased our allowance for doubtful accounts and bad debt expense by approximately $9.9 million for June 2008 production that was recorded in June 2008. We believe that we have an additional $6.8 million of potential exposure with SemGroup for a portion of production related to July 2008. We are monitoring the bankruptcy proceedings closely to determine and pursue the best course of action that would result in the collection of the amounts owed and the continuation of crude oil sales in the affected producing regions. This matter does not have a material adverse effect on our liquidity or overall financial position.

Outlook for the Remainder of 2008

Commodity prices and drilling and well completion costs are the most significant drivers of our business. Forecasted natural gas and crude oil futures prices for the remainder of the year are currently higher than those used to prepare our 2008 budget. These prices are highly volatile, and as a result we evaluate whether the forecasted future commodity prices at the time we propose to drill or elect to participate in the drilling of a well with a partner meet our economic criteria given the cost environment at that time. 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. Strong commodity prices have led to increased levels of capital investment in the exploration and production segment of our industry. Service providers continue to increase their prices and we believe that this is a trend that is likely to continue in the near term. Additionally, shortages of items used in the drilling and completion of wells, principally drill pipe and sand, are becoming more common. We believe that we have the rigs and services contracted to carry out our current drilling program. However there is upward pressure on the cost to execute that program and there could be limitations on our ability to expand the program. Despite these potential challenges, our programs are highly economic in the current price and cost environment.

- Mid-Continent – Our plans for the remainder of 2008 in the Mid-Continent region include operating three rigs in the horizontal Woodford Shale program in the Arkoma Basin, and continuing our development and exploration activities in the Anadarko Basin. We increased our capital investment budget for the Woodford program in the second quarter by $20 million based on improvements in our well results. 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. Additionally, our technical team in the region is evaluating whether horizontal development could improve or enhance the economics in this program. 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 primarily focused on programs that target the Cotton Valley and the James Lime formations. We plan to operate two horizontal rigs throughout the region for the remainder of the year and utilize a vertical rig for several vertical Cotton Valley wells. We also plan to drill at least two wells to test the Haynesville shale on our acreage later this year.

- 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. We currently have four operated rigs running in the Sweetie Peck program. We are drilling wells in three 40-acre infill pilot areas this year to test the downspacing potential of the Wolfberry at Sweetie Peck. Drilling wells on 40-acres spacing has the potential to add meaningful reserves if successful. We also plan to continue participating in Wolfberry wells at Halff East, where our partner has indicated they may expand the drilling program later 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 rigs in the play for the remainder of the year. We plan to continue evaluating our existing 3D seismic data over the properties. Additionally, we are examining several other potential resource plays in the region.

Also in the Maverick Basin, earlier this year we 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 significant additional acreage and reserve potential in the basin.

- 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 currently have one operated drilling rig focused on the horizontal Bakken program in North Dakota. We are currently completing our first grass roots horizontal well and are drilling our second grass roots horizontal well. We also currently have a re-entry rig operating for us that is drilling wells that target the Bakken. In addition, we are evaluating the prospectivity of the Three Forks formation, which lies below the Bakken in much of western North Dakota. We recently agreed to acquire an additional 24,700 net acres in North Dakota which has Bakken potential and could also be prospective for the Three Forks. We continue to participate with operating partners in various projects throughout the Rocky Mountain region.

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, service and supply availability, 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 large numbers 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 reserves and production. Our strong balance sheet gives us the ability to move quickly when we find an acquisition target.

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

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

	For the Three Months Ended June 30, 2008	2007	Percent Change Between Periods	For the Six Months Ended June 30, 2008	2007	Percent Change Between Periods
Net production volumes						
Oil (MBbl)	1,644	1,698	(3)%	3,312	3,407	(3)%
Natural gas (MMcf)	18,684	15,848	18%	37,027	31,068	19%
MMCFE (6:1)	28,551	26,033	10%	56,898	51,509	10%
Average daily production						
Oil (Bbl per day)	18,071	18,655	(3)%	18,197	18,823	(3)%
Natural gas (Mcf per day)	205,322	174,150	18%	203,443	171,645	19%
MCFE per day (6:1)	313,748	286,082	10%	312,626	284,581	10%
Oil & gas production revenues(1)						
Oil production revenue	$ 145,365	$ 101,803	43%	$ 272,493	$ 191,753	42%
Gas production revenue	186,200	121,654	53%	345,554	244,094	42%
Total	$ 331,565	$ 223,457	48%	$ 618,047	$ 435,847	42%
Oil & gas production expense						
Lease operating expenses	$ 40,975	$ 31,629	30%	$ 76,080	$ 65,754	16%
Transportation costs	5,624	4,159	35%	9,501	8,606	10%
Production taxes	27,026	14,540	86%	47,520	28,288	68%
Total	$ 73,625	$ 50,328	46%	$ 133,101	$ 102,648	30%
Average realized sales price(1)						
Oil (per Bbl)	$ 88.40	$ 59.97	47%	$ 82.28	$ 56.28	46%
Natural gas (per Mcf)	$ 9.97	$ 7.68	30%	$ 9.33	$ 7.86	19%
Per MCFE Data:						
Average net realized price(1)	$ 11.61	$ 8.58	35%	$ 10.86	$ 8.46	28%
Lease operating expenses	(1.43)	(1.21)	18%	(1.33)	(1.28)	4%
Transportation costs	(0.20)	(0.16)	25%	(0.17)	(0.17)	-%
Production taxes	(0.95)	(0.56)	70%	(0.84)	(0.55)	53%
General and administrative	(0.77)	(0.62)	24%	(0.76)	(0.56)	36%
Operating profit	$ 8.26	$ 6.03	37%	$ 7.76	$ 5.90	32%
Depletion, depreciation, amortization, and asset	$ 2.67	$ 2.10	27%	$ 2.58	$ 2.01	28%

retirement obligation
liability accretion

(1) Includes the effects of hedging activities.

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

	June 30, 2008	December 31, 2007	Percent Change Between Periods
Working deficit	$ (249,900)	$ (92,604)	170%
Long-term debt	$ 582,500	$ 572,500	2%
Stockholders' equity	$ 540,383	$ 863,345	(37)%

	For the Three Months Ended June 30, 2008	2007	Percent Change Between Periods	For the Six Months Ended June 30, 2008	2007	Percent Change Between Periods
Basic net income per common share	$ 0.54	$ 0.93	(42)%	$ 2.08	$ 1.64	27%
Diluted net income per common share	$ 0.53	$ 0.91	(42)%	$ 2.04	$ 1.54	32%
Basic weighted-average shares outstanding	61,714	63,583	(3)%	62,287	60,316	3%
Diluted weighted-average shares outstanding	62,749	65,120	(4)%	63,404	65,015	(2)%

We present this table as a summary of information relating to key indicators of financial condition and operating performance which 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. 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 required 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. We continue to add employees as we execute our business plan. The increase in personnel drives general and administrative costs higher. 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. There is no impact on the diluted share calculation for the periods presented since the Company's average stock price for the relevant reporting periods has not exceeded the conversion price. The 3.50% Senior Convertible Notes were issued April 4, 2007, and have not been dilutive for any reporting period 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 June 30, 2008, and 2007, reflect an increase in outstanding shares related to stock option exercises. We issued 812,376 and 385,948 shares of common stock during the six-month periods ended June 30, 2008, and 2007, respectively, as a result of stock option exercises. Additionally, during the first six months of 2008 and 2007, we issued 407,319 and 302,370 shares of common stock, respectively, as a result of converting RSUs to common stock in accordance with the terms of the RSU grants.

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 cash proceeds from this transaction were $129.6 million. We anticipate that we will continue to evaluate our property base for divestiture candidates that we do not consider to be strategic to our growth.

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 size of the borrowing base provided under our credit facility as well as the value of non-strategic properties we might consider selling. The public debt markets for energy companies continue to be available to us. The energy sector has accounted for a large amount of new issuance activity, and is the most active sector year to date. Equity and convertible debt financings are still an available alternative for 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. 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.

Current credit facility

We have a $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 facility 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 July 29, 2008, we had $235 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. Borrowings under the facility reduce the amount available under the commitment amount on a dollar-for-dollar basis. Borrowings under the

facility are secured by mortgages on the majority of our oil and gas properties and 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 $295.0 million as of June 30, 2008.

Our weighted-average interest rate paid in the three-month and six-month periods ended June 30, 2008, was 4.6 percent and 4.9 percent, respectively, 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 six months of 2008 we spent $329.2 million for capital development and $62.9 million for property acquisitions. These cash outflows were funded using cash inflows from operations, proceeds from asset divestitures, and borrowings 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 currently 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.

As of the date of this filing we have Board authorization to repurchase up to 3,072,184 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 May 12, 2008, we paid $3.1 million in dividends to stockholders of record as of the close of business May 2, 2008. Our intention is to continue to make these semi-annual dividend payments for the foreseeable future subject to our future cash flows, our financial condition, possible credit facility covenants, and other currently unexpected factors which could arise.

The following table presents amounts and percentage changes in cash flows between the six-month periods ended June 30, 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 Six Months Ended June 30, 2008	2007	Change	Percent Change
	(In thousands)			
Net cash provided by operating activities	$ 316,095	$ 282,321	$ 33,774	12%
Net cash used in investing activities	$ (272,657)	$ (302,331)	$ 29,674	(10)%
Net cash provided by (used in) financing activities	$ (50,029)	$ 44,725	$ (94,754)	(212)%

Analysis of cash flow changes between the six months ended June 30, 2008, and June 30, 2007

Operating activities. Cash received from oil and gas production revenue, net of the realized effects of hedging, increased $153.8 million to $584.7 million for the six-month period ended June 30, 2008, compared with $430.8 million for the six-month period ended June 30, 2007. Included in operating revenues as of June 30, 2008, is $92.3 million of net realized hedging losses. The 42 percent increase in oil and gas production revenue, net of the realized effects of hedging, was the result of a 10 percent increase in production and a 28 percent increase in our net realized price after hedging. Net cash payments made for income taxes in the first six months of 2008 increased $17.5 million relative to the same period in 2007.

Investing activities. Total cash outflow for capital expenditures during the six months ended June 30, 2008, for leasehold and drilling activities increased $50.3 million or 18 percent to $329.2 million. Cash proceeds from the sale of oil and gas properties for the six-month period ended June 30, 2008, includes $129.6 million related to the Abraxas divestiture completed on January 31, 2008 and $22.1 million related to the Greater Green River Basin divestiture completed in June of 2008. Total cash outflow for the six months ended June 30, 2008, relating to the acquisition of oil and gas properties increased $31.9 million to $62.9 million due to the acquisition of assets at Carthage Field. Deposits to restricted cash equaled $25.3 million for the six months ended June 30, 2008, compared to no deposits to restricted cash for the same period in 2007. Other cash flows from investing activities for the first quarter of 2008 include the refunding of a $10.0 million deposit related to the Abraxas divestiture.

Financing activities. Net repayments to our credit facility decreased $248.0 million for the six-month period ended June 30, 2008, compared with the same period in 2007. Cash flows from financing activities for the six months ended June 30, 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 during the six-month period ended June 30, 2008. We received $281.2 million less in the six-month period ended June 30, 2008, compared to the same period in 2007 as a result of the issuance of convertible debt in the second quarter of 2007. Our income tax benefit attributable to the exercise of stock options increased $5.8 million. We received $5.3 million more from the sale of common stock for the six-month period ended June 30, 2008, compared to the same period in 2007.

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.

	Exploration and Development Investment Budget (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 investment budget to reflect changes in current and projected cash flows, acquisition opportunities, drilling opportunities, debt requirements, regional cost inflation, service and supply availability, 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 Six Months Ended June 30,	
	2008	2007
	(In thousands)	
Development costs	$ 305,690	$ 254,573
Exploration costs	53,710	67,774
Acquisitions:		
Proved	37,578	31,277
Unproved	25,696	(227)
Leasing activity	13,723	24,138
Total, including asset retirement obligation	$ 436,397	$ 377,535

Costs incurred for capital and exploration activities during the first six months of 2008 increased $58.9 million or 16 percent compared to the same period in 2007. Excluding acquisitions, our development and exploration investments increased $37.1 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 six months of 2008 compared with the same period in 2007. The $21.8 million increase in acquisitions is primarily attributable to the acquisition of oil and gas properties located in the Carthage Field in East Texas. 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. Given strong commodity prices and continued shortages for items such as steel and sand, we expect continue upward pressure on completed well cost.

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 leasehold and producing property 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 of 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 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 may 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. Refer to 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 fix the price on a significant portion of an equivalent amount of existing production to the prices we used to evaluate the risked production of an acquisition. We also hedge a portion of our forecasted production on a discretionary basis. As of June 30, 2008, our hedged positions totaled approximately 10 million Bbls of crude oil, 73 million MMBtu of natural gas, and 1 million Bbls of natural gas liquids of 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 June 30, 2008.

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Oil Contracts

Oil Swaps			
Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at June 30, 2008 Liability
	(Bbl)	(Per Bbl)	(In thousands)
Third quarter 2008			
NYMEX WTI	481,000	$ 71.91	$ 32,798
WCS	45,000	$ 54.03	2,919
Fourth quarter 2008			
NYMEX WTI	451,000	$ 71.83	30,806
WCS	15,000	$ 50.42	1,030
2009			
NYMEX WTI	1,570,000	$ 71.64	103,319
2010			
NYMEX WTI	1,239,000	$ 66.47	80,184
2011			
NYMEX WTI	1,032,000	$ 65.36	62,601
All oil swap contracts	4,833,000		$ 313,657

Oil Collars				
Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at June 30, 2008 Liability
	(Bbl)	(Per Bbl)	(Per Bbl)	(In thousands)
Third quarter 2008	514,000	$ 57.86	$ 78.08	$ 32,003
Fourth quarter 2008	519,000	$ 58.19	$ 78.43	32,427
2009	1,526,000	$ 50.00	$ 67.31	107,329
2010	1,367,500	$ 50.00	$ 64.91	91,597
2011	1,236,000	$ 50.00	$ 63.70	77,665
All oil collars	5,162,500			$ 341,021

Gas Contracts

Gas Swaps			
Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at June 30, 2008 Liability
	(MMBtu)	(per MMBtu)	(In thousands)
Third quarter 2008 -			
IF CIG	930,000	$ 6.91	$ 1,973
IF PEPL	1,460,000	$ 7.48	5,459
IF NGPL	190,000	$ 6.69	888
IF ANR OK	640,000	$ 7.92	2,198
IF EL PASO	280,000	$ 7.16	1,290
IF HSC	1,490,000	$ 8.22	7,096
NYMEX Henry Hub	270,000	$ 9.38	1,053
Fourth quarter 2008 -			
IF CIG	930,000	$ 7.45	1,958
IF PEPL	1,490,000	$ 8.32	4,708
IF NGPL	160,000	$ 7.10	752
IF ANR OK	610,000	$ 8.22	2,147
IF EL PASO	300,000	$ 7.20	1,399
IF HSC	2,100,000	$ 8.77	9,313
NYMEX Henry Hub	270,000	$ 9.72	1,084
2009 -			
IF CIG	2,310,000	$ 7.72	3,868
IF PEPL	3,360,000	$ 8.06	10,773
IF NGPL	440,000	$ 7.11	1,777
IF ANR OK	1,340,000	$ 8.09	4,483
IF EL PASO	1,200,000	$ 7.11	4,746
IF HSC	10,490,000	$ 8.57	35,454
NYMEX Henry Hub	1,280,000	$ 9.03	4,181
2010 -			
IF NGPL	60,000	$ 7.60	219
IF ANR OK	60,000	$ 7.98	186
IF EL PASO	1,090,000	$ 6.79	3,421
IF HSC	6,080,000	$ 8.40	14,909
NYMEX Henry Hub	1,440,000	$ 8.66	3,365
2011 -			
IF EL PASO	880,000	$ 6.34	2,711
IF HSC	360,000	$ 9.01	722
All gas swap contracts	41,510,000		$ 132,133

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Gas Collars				
Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at June 30, 2008 Liability
	(MMBtu)	(per MMBtu)	(per MMBtu)	(In thousands)
Third quarter 2008 -				
IF CIG	720,000	$ 5.60	$ 8.72	$ 422
IF PEPL	1,657,500	$ 6.28	$ 9.42	3,112
IF HSC	240,000	$ 6.57	$ 9.70	793
IF RELIANT	1,000,000	$ 8.75	$ 10.20	1,500
NYMEX Henry Hub	120,000	$ 7.00	$ 10.57	315
Fourth quarter 2008 -				
IF CIG	720,000	$ 5.60	$ 8.72	1,079
IF PEPL	1,657,500	$ 6.28	$ 9.42	3,997
IF HSC	240,000	$ 6.57	$ 9.70	879
IF RELIANT	1,220,000	$ 8.75	$ 10.20	2,374
NYMEX Henry Hub	120,000	$ 7.00	$ 10.57	408
2009 -				
IF CIG	2,400,000	$ 4.75	$ 8.82	3,282
IF PEPL	5,510,000	$ 5.30	$ 9.25	13,376
IF HSC	840,000	$ 5.57	$ 9.49	2,518
NYMEX Henry Hub	360,000	$ 6.00	$ 10.35	973
2010 -				
IF CIG	2,040,000	$ 4.85	$ 7.08	3,032
IF PEPL	4,945,000	$ 5.31	$ 7.61	13,789
IF HSC	600,000	$ 5.57	$ 7.88	1,826
NYMEX Henry Hub	240,000	$ 6.00	$ 8.38	704
2011 -				
IF CIG	1,800,000	$ 5.00	$ 6.32	3,996
IF PEPL	4,225,000	$ 5.31	$ 6.51	13,539
IF HSC	480,000	$ 5.57	$ 6.77	1,583
NYMEX Henry Hub	120,000	$ 6.00	$ 7.25	378
All gas collars	31,255,000			$ 73,875

Natural Gas Liquid Contracts

Natural Gas Liquid Swaps*			
Contract Period	Volumes (Bbls)	Weighted-Average Contract Price (per Bbl)	Fair Value at June 30, 2008 Liability (In thousands)
Third quarter 2008	205,320	$ 40.22	$ 7,755
Fourth quarter 2008	245,992	$ 40.79	8,505
2009	813,732	$ 41.87	21,064
2010	139,724	$ 49.59	1,313
2011	19,642	$ 49.01	242
All natural gas liquid swaps	1,424,410		$ 38,879

*Natural gas liquid swaps are comprised of OPIS Mont. Belvieu TET Propane (26%), OPIS Mont. Belvieu Purity Ethane (46%), OPIS Mont. Belvieu NON-TET Isobutane (9%), OPIS Mont. Belvieu NON-TET Natural Gasoline (13%), and OPIS Mont. Belvieu NON-TET Normal Butane (6%).

Refer to 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, which we believe are not material to our financial position, 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 June 30, 2008, and 2007	Change Between the Six Months Ended June 30, 2008, and 2007
Oil and gas production revenues		
Increase in oil and gas production revenues, net of hedging (In thousands)	$ 108,108	$ 182,200

Components of revenue increases (decreases):

Oil		
Realized price change per Bbl, including the effects of hedging	$ 28.43	$ 26.00
Realized price percentage change	47%	46%
Production change (MBbl)	(54)	(95)
Production percentage change	(3)%	(3)%
Natural Gas		
Realized price change per Mcf, including the effects of hedging	$ 2.29	$ 1.47
Realized price percentage change	30%	19%
Production change (MMcf)	2,836	5,959
Production percentage change	18%	19%

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
Revenue	2008	2007	2008	2007
Oil	44%	46%	44%	44%
Natural gas	56%	54%	56%	56%
Production				
Oil	35%	39%	35%	40%
Natural gas	65%	61%	65%	60%

Information Regarding the Components of Exploration Expense:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2008	2007	2008	2007
Summary of Exploration Expense	(In millions)		(In millions)	
Geological and geophysical expenses	$ 1.4	$ 2.3	$ 3.1	$ 5.0
Exploratory dry hole expense	5.9	1.7	6.6	11.2
Overhead and other expenses	10.1	7.1	22.0	13.9
Total	$ 17.4	$ 11.1	$ 31.7	$ 30.1

Information Regarding the Effects of Oil and Gas Hedging Activity:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2008	2007	2008	2007
Oil Hedging				
Percentage of oil production hedged	63%	65%	60%	65%
Oil volumes hedged (MBbl)	1,004	1,110	1,997	2,217
Decrease in oil revenue	$ (52.3 million)	$ (1.9 million)	$ (79.1 million)	$ (1.9 million)
Average realized oil price per Bbl before hedging	$ 120.20	$ 61.11	$ 106.17	$ 56.85
Average realized oil price per Bbl after hedging	$ 88.40	$ 59.97	$ 82.28	$ 56.28
Natural Gas Hedging				
Percentage of gas production hedged	43%	46%	41%	46%
Natural gas volumes hedged (MMBtu)	$ 8.6 million	$ 7.8 million	$ 16.1 million	$ 15.3 million
Increase (decrease) in gas revenue	$ (16.1 million)	$ 9.2 million	$ (13.2 million)	$ 27.9 million
Average realized gas price per Mcf before hedging	$ 10.83	$ 7.09	$ 9.69	$ 6.96
Average realized gas price per Mcf after hedging	$ 9.97	$ 7.68	$ 9.33	$ 7.86

Comparison of Financial Results and Trends between the three months ended June 30, 2008, and 2007

Oil and gas production revenue. Production increased 10 percent to 28.6 BCFE for the quarter ended June 30, 2008, compared with 26.0 BCFE for the quarter ended June 30, 2007. The production for the quarter ended June 30, 2007, includes approximately 1.2 BCFE related to non-core properties divested of on January 31, 2008. The following table presents the regional changes in our production and oil and gas revenues and costs between the two quarters:

	Production Added (Lost) (MMCFE)	Pre-Hedge Oil and Gas Revenue Added (Lost) (In millions)	Production Costs Added (Lost) (In millions)

Mid-Continent	(606.3) $	19.8 $	2.4
Rocky Mountain	(885.3)	61.1	6.9
ArkLaTex	988.2	26.9	2.2
Permian	932.4	39.0	5.0
Gulf Coast	2,088.6	37.0	6.8
Total	2,517.6 $	183.8 $	23.3

Year over year, we were able to grow production in most of our regions in the second quarter of 2008. The large increase in the Gulf Coast region reflects the acquisition and subsequent development of our Olmos shallow gas assets in the Maverick Basin of South Texas and the success of several offshore wells. The Olmos properties were acquired in the second half of 2007. The increase in production in the

ArkLaTex region is the result of the successful Cotton Valley (including Elm Grove, Terryville, and Carthage) and James Lime programs where we have been increasing our capital investment. Production increased in the Permian due to continued successful drilling in our Wolfberry tight oil program. We saw declines in production in the Mid-Continent and Rocky Mountain regions a result of natural production declines as well as smaller amounts of capital being invested in these regions in recent quarters.

The following table summarizes the average realized prices, before the effects of hedging, we received in the second quarter of 2007 and 2008. Prices for oil and gas increased significantly between the two periods.

	For the Three Months Ended June 30,	
	2008	2007
Realized oil price ($/bbl)	$ 120.20	$ 61.11
Realized gas price ($/Mcf)	$ 10.83	$ 7.09
Realized equivalent price ($/MCFE)	$ 14.01	$ 8.30

The combination of higher production volume and higher commodity prices between periods resulted in higher oil and gas revenue.

Realized oil and gas hedge gain (loss). We recorded a realized hedge loss of $68.4 million for the three-month period ended June 30, 2008, mainly related to settlements on oil hedges.

Oil and gas production expense. Total production costs increased $23.3 million, or 46 percent, to $73.6 million for the second quarter of 2008 from $50.3 million in the comparable period of 2007. Total oil and gas production costs per MCFE increased $0.65 to $2.58 for the second quarter of 2008, compared with $1.93 for the same period in 2007. This increase is comprised of the following:

- A $0.04 increase in overall transportation cost on a per MCFE basis was driven by the addition of Olmos shallow gas assets in the Maverick Basin that were acquired in the second half of 2007, as well as recently completed wells which have higher transportation costs

- A $0.39 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

- A $0.09 increase in recurring LOE on a per MCFE basis is related to higher costs, particularly in oil-weighted regions, for items such as fuel and fluid disposal and an increase in the Gulf Coast region due to wells acquired and developed in South Texas that were acquired during the fourth quarter of 2007

- A $0.13 overall increase in workover LOE on a per MCFE basis relating to workover charges in the Gulf Coast and Mid-Continent regions.

Depletion, depreciation, amortization and asset retirement obligation liability accretion. DD&A increased $21.7 million or 40 percent to $76.4 million for the three-month period ended June 30, 2008, compared with $54.7 million for the same period in 2007. DD&A expense per MCFE increased 27 percent to $2.67 for the three-month period ended June 30, 2008, compared to $2.10 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 2007 and 2006 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.

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Exploration. Exploration expense increased $6.3 million or 57 percent to $17.4 million for the three-month period ended June 30, 2008, compared with $11.1 million for the same period in 2007. This increase is due to an $6.0 million increase in exploratory dry hole expense related to two wells located in the ArkLaTex region that were determined to be non-commercial during the second quarter of 2008.

General and administrative. General and administrative expense increased $5.6 million or 34 percent to $21.9 million for the quarter ended June 30, 2008, compared with $16.3 million for the comparable period of 2007. G&A increased $0.15 to $0.77 per MCFE for the second quarter of 2008 compared to $0.62 per MCFE for the same three-month period in 2007.

A significant increase in employee count has resulted in an increase in base employee compensation, including taxes and benefits, of approximately $3.5 million between the second quarter of 2008 and the second quarter of 2007. A $3.4 million increase in Net Profits Plan payments is the result of increased oil and gas commodity prices, which resulted in larger Net Profits Plan payments to plan participants. As of the end of the second quarter of 2008, 17 of our 21 pools are currently in payout status. No additional pools are expected to reach payout in 2008.

Cash and RSU bonus expense is $2.2 million higher than in the prior year, which is primarily caused by the increase in employee count and current company performance. The above amounts combined with a net $1.0 million increase in other G&A expense, which includes charitable contributions and office supplies, were offset by a $1.8 million increase in the amount of general and administrative expense that was allocated to exploration expense, as well as a $2.7 million increase in COPAS overhead reimbursements. COPAS overhead reimbursements from operations increased due to an increase in our operated well count.

Bad debt expense. For the quarter ended June 30, 2008, we recorded $9.9 million of bad debt expense as a result of SemGroup, a purchaser of our crude oil, filing for bankruptcy protection. This amount related to oil produced in June 2008 that was reserved in the three-month period ended June 30, 2008. We believe that we have an additional $6.8 million of potential exposure with SemGroup for a portion of July 2008 production. We are monitoring the bankruptcy proceedings closely to determine and pursue the best course of action that would result in the collection of the amounts owed and the continuation of crude oil sales in the producing regions affected.

Change in Net Profits Plan liability. For the quarter ended June 30, 2008, this non-cash expense was $68.1 million compared to a benefit of $1.2 million for the same period in 2007. Significant increases in oil and gas commodity prices have triggered additional Net Profits Plan payouts and have increased the estimate of future amounts to be paid 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 tax expense. Income tax expense totaled $19.2 million for the second quarter of 2008 compared with $35.2 million for the second quarter of 2007 resulting in effective tax rates of 36.4 percent and 37.3 percent, respectively. The decrease in income tax expense is primarily the result of the differences in components of net income discussed above. The decrease in effective tax rate 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 expense increased for the second quarter of 2008 compared to the same period of 2007 due to the impact on estimated taxable income of higher crude oil and natural gas sales between the two periods that were not offset by proportionate increases in estimated deductible amounts, particularly additional intangible drilling cost deductions related to capital spending and incentive compensation program related expenses.

Comparison of Financial Results and Trends between the six months ended June 30, 2008, and 2007

Oil and gas production revenue. Production increased 10 percent to 56.9 BCFE for the six months ended June 30, 2008, compared with 51.5 BCFE for the six months ended June 30, 2007. The production for the six-month periods ended June 30, 2008, and 2007, includes approximately 0.4 BCFE and 2.4 BCFE, respectively, related to non-core properties divested of on January 31, 2008. The following table presents the regional changes in our production, and oil and gas revenues and costs:

	Production Added (Lost) (MMCFE)	Pre-Hedge Oil and Gas Revenue Added (Lost) (In millions)	Production Costs Added (Lost) (In millions)
Mid-Continent	(486.8)	$ 34.8	$ 3.2
Rocky Mountain	(2,151.4)	94.3	4.3
ArkLaTex	2,432.7	44.4	3.8
Permian	1,821.9	66.8	7.4
Gulf Coast	3,772.4	60.2	11.8
Total	5,388.8	$ 300.5	$ 30.5

We grew production by roughly 5,400 MMCFE in the first half of 2008 compared to the same period the year before. The largest regional increase occurred in the Gulf Coast region as a result of two acquisitions of properties targeting the shallow Olmos gas formation that were made in the second half of 2007 as well as several successful offshore wells. Continued success in the Cotton Valley and James Lime programs in the ArkLaTex region has allowed for increased capital investment in recent quarters, driving growth of production for the region. The production growth in the Permian is the result of continued development of the Wolfberry assets at Sweetie Peck and Halff East. The declines in production in the Mid-Continent and Rocky Mountain regions is the result of decreased capital investment in these regions as we allocate capital to higher rate of return projects and regions.

The following table summarizes the average realized prices we received in the first half of 2007 and 2008. Prices for oil and gas increased significantly between the two periods.

	For the Six Months Ended June 30, 2008	2007
Realized oil price ($/bbl)	$ 106.17	$ 56.85
Realized gas price ($/Mcf)	$ 9.69	$ 6.96
Realized equivalent price ($/MCFE)	$ 12.49	$ 7.96

The combination of higher production volume and higher commodity prices resulted in higher oil and gas revenue.

Realized oil and gas hedge gain (loss). We recorded a realized hedge loss of $92.3 million for the six-month period ended June 30, 2008, mainly related to settlements on oil hedges. In the first half of 2007 we realized a $26.0 million hedge gain mainly due to favorable settlements on natural gas hedges.

Gain on sale of proved properties. We recorded a gain on sale of proved properties of $59.1 million during the first half of 2008 mainly 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 third quarter of 2008. There were no sales of proved properties during the first half of 2007. We expect to continue to evaluate potential divestitures of non-strategic properties.

Oil and gas production expense. Total production costs increased $30.5 million, or 30 percent, to $133.1 million for the six-month period ended June 30, 2008, from $102.6 million in the comparable period of 2007. Total oil and gas production costs per MCFE increased $0.34 to $2.34 for the first six months of 2008, compared with $2.00 for the same period in 2007. This increase is comprised of the following:

- A $0.29 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

- A $0.04 overall increase in recurring LOE on a per MCFE basis, is related to an increase in operating costs in the Permian Basin related to increased fuel prices and water disposal as well as an increase in the Gulf Coast region due to wells acquired in the Olmos formation during the fourth quarter of 2007

- Overall workover LOE on a per MCFE basis increased $0.01.

Depletion, depreciation, amortization and asset retirement obligation liability accretion. DD&A increased $43.1 million or 42 percent to $146.7 million for the six-month period ended June 30, 2008, compared with $103.6 million for the same period in 2007. DD&A expense per MCFE increased 28 percent to $2.58 for the six-month period ended June 30, 2008, compared to $2.01 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 2007 and 2006 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. Exploration expense increased $1.6 million or 5 percent to $31.7 million for the six-month period ended June 30, 2008, compared with $30.1 million for the same period in 2007. For the six-month period ended June 30, 2008, and 2007, we recorded $6.0 million related to two wells located in the ArkLaTex region and $7.7 million related to two wells located in the Gulf Coast region and one in the Rocky Mountain region, respectively, for exploratory dry holes. However, we also realized an 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 $13.8 million or 47 percent to $43.0 million for the six months ended June 30, 2008, compared with $29.1 million for the comparable period of 2007. G&A increased $0.20 to $0.76 per MCFE for the first six months of 2008 compared to $0.56 per MCFE for the same period in 2007.

A 28 percent increase in employee count has resulted in an increase in base employee compensation, including payroll taxes and benefits, of approximately $6.8 million between the first six months of 2008 and the same period in 2007. An $8.2 million increase in Net Profits Plan payments is the result of increased oil and gas commodity prices, which result in larger Net Profits Plan payments to plan participants.

Cash and RSU bonus expense is $3.5 million higher than in the prior year, which is primarily caused by the increase in employee count and current company performance. The above amounts combined with a net $4.0 million increase in other G&A expense, which includes charitable contributions and office supplies, were offset by a $4.5 million increase in the amount of general and administrative expense that was allocated to exploration expense, as well as a $4.2 million increase in COPAS overhead

reimbursements. A portion of the increase in the amount of general and administrative expense is due to G&A related to the aforementioned incentive plan which is no longer allocated to exploration expense. COPAS overhead reimbursements from operations increased due to an increase in our operated well count.

Bad debt expense. We recorded $9.9 million of bad debt expense as a result of SemGroup, a purchaser of our crude oil, filing for bankruptcy protection. This amount related to oil produced in June 2008 that was reserved in the six-month period ended June 30, 2008.

Change in Net Profits Plan liability. For the six-month period ended June 30, 2008, this non-cash expense was $81.8 million compared to $3.8 million for the same period in 2007. Increases in oil and gas commodity prices have triggered additional Net Profits Plan payouts and have increased the estimate of the amounts forecasted to be paid to plan participants.

Income tax expense. Income tax expense totaled $75.7 million for the six-month period of 2008 compared with $58.8 million for the same period of 2007 resulting in effective tax rates of 36.9 percent and 37.2 percent, respectively. The increase in income tax expense is primarily the result of the differences in components of net income discussed above. The decrease in effective tax rate 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 expense increased in real dollars and on a percentage basis for the six months ended June 30, 2008 compared to the six months ended June 30, 2007 due primarily to the impact on estimated taxable income of higher crude oil and natural gas sales between the two periods.

New Accounting Pronouncements

We refer you to Note 11 – Fair Value Measurements and Note 14 – Recent Accounting Pronouncements 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.

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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 this Quarterly Report on Form 10-Q, 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

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- 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
- The ability of purchasers of production to pay for amounts purchased
- 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, except as follows:

On July 22, 2008, SemGroup, a purchaser of a portion of the Company's crude oil production in the Williston Basin, Oklahoma and Texas, filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code. As a result, the Company increased its allowance for doubtful accounts and bad debt expense by approximately $9.9 million for June 2008 production sold to SemGroup that was recorded in June 2008. St. Mary believes that it has an additional $6.8 million of potential exposure with SemGroup for a portion of production related to July 2008. The Company is monitoring the bankruptcy proceedings closely to determine and pursue the best course of action that would result in the collection of the amounts owed and the continuation of crude oil sales in the producing regions affected. While this matter does not have a material adverse effect on the Company's liquidity or overall financial position, it may have a material effect on future results of operations.

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 June 30, 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)
04/01/08 – 04/30/08	1,547	$ 39.84	-0-	3,072,184
05/01/08 – 05/31/08	550	$ 47.98	-0-	3,072,184
06/01/08 – 06/30/08	30	$ 62.78	-0-	3,072,184
Total:	2,127	$ 42.27	-0-	3,072,184

(1) Includes a total of 1,000 shares purchased by Anthony J. Best, St. Mary's President and Chief Executive Officer, in open market transactions that were not made pursuant to our stock repurchase program. The table does not include the 647 shares purchased by Mr. Best under the Company's employee stock purchase plan.

(2) Includes 1,127 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 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

At the Company's annual stockholders' meeting on May 21, 2008, the stockholders elected management's current slate of directors and approved the three additional proposals described below. Each director was elected by a majority vote. The directors elected and the vote tabulation for each director were as follows:

Director	For	Withheld
Barbara M. Baumann	56,928,903	747,461
Anthony J. Best	57,115,327	561,037
Larry W. Bickle	56,805,248	871,116
William J. Gardiner	57,103,389	572,975
Mark A. Hellerstein	57,139,847	536,517
Julio M. Quintana	57,254,574	421,790
John M. Seidl	57,148,939	527,425
William D. Sullivan	56,880,475	795,889

The stockholders also approved the proposal to approve the Amendment and Restatement of the 2006 Equity Incentive Compensation Plan to increase the number of shares available for issuance under the plan, to specifically provide for and describe the general terms of awards of performance shares and performance units, and to modify the change of control provisions of prospective equity awards to require a "double-trigger" of both a change of control event and a termination or substantial change in employment in order for vesting to accelerate. The proposal was approved by a majority vote. The tabulation of votes for that proposal was as follows:

For	39,675,431
Against	10,230,259
Abstain	1,505,813
Non Votes	6,264,859

The stockholders also approved the proposal to approve the Cash Bonus Plan to ensure that incentive compensation paid under the plan can be eligible for the "performance-based compensation" exemption from the limits on tax deductibility imposed by Section 162(m) of the Internal Revenue Code. The proposal was approved by a majority vote. The tabulation of votes for that proposal was as follows:

For	51,990,813
Against	3,975,980
Abstain	1,709,571

The stockholders also approved the proposal to ratify the appointment by the Audit Committee of Deloitte & Touche, LLP as the Company's independent registered public accounting firm. The proposal was approved by a majority vote. The tabulation of votes for that proposal was as follows:

For	57,615,641
Against	17,419
Abstain	43,304

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."

Appointment of Chief Financial Officer

On August 4, 2008, the Company issued a press release announcing that Mr. A. Wade Pursell will be joining the Company as Executive Vice President and Chief Financial Officer effective September 8, 2008. At that time, Mr. Mark T. Solomon will relinquish his position as Acting Principal Financial Officer of the Company and will continue to serve as Controller of the Company. A copy of the press release announcing Mr. Pursell's appointment is attached as Exhibit 99.1 to this report.

Mr. Pursell, age 43, has over twenty years of experience in financial and accounting positions. From 1997 through July 4, 2008, he was employed at Helix Energy Solutions Group, Inc., a publicly traded energy services company, as Executive Vice President and Chief Financial Officer from February 2007 through July 4, 2008, Senior Vice President and Chief Financial Officer from October 2000 through February 2007, and Vice President - Finance and Chief Accounting Officer from May 1997 through October 2000. From 1988 through May 1997, Mr. Pursell worked at Arthur Andersen LLP in positions of increasing responsibility from Accountant to Senior Manager and specialized in the Oilfield Services Industry. He received a Bachelor of Science degree from the University of Central Arkansas.

Mr. Pursell will receive an initial annual base salary of $300,000. Upon hiring, Mr. Pursell will receive a $25,000 signing bonus and an additional $25,000 will be paid to Mr. Pursell after six months of employment. Additionally, upon commencement of employment, Mr. Pursell will receive a special restricted stock unit award worth $600,000, of which one-half will vest on December 15, 2009, and the remaining half will vest on December 15, 2010, provided that on such vesting dates Mr. Pursell is employed by the Company. The restriction to sell the vested shares will lapse on the respective vesting dates. Mr. Pursell will participate in the incentive compensation and other benefit plans and practices of St. Mary in the same manner and to the same comparable extent as other senior executives of St. Mary, to be prorated for partial year(s) of employment.

Mr. Pursell will be moving to the Denver, Colorado area in the near term and will receive reimbursement of relocation costs as well as a four week stipend of $25,000 to offset other miscellaneous moving expenses.

Mr. Pursell currently is not and has not previously been a party to any reportable related person transaction with the Company.

Compensatory Arrangements of Certain Officers

On August 1, 2008, the Company granted performance share awards (the "2008 PSAs") pursuant to the Company's new long term incentive program ("LTIP") under the Company's 2006 Equity Incentive Compensation Plan, as amended and restated as of March 28, 2008 (the "Plan"), to various employees of the Company selected to participate in the LTIP, including the named executive officers of the Company listed below. The grants of the performance share awards were approved by the Compensation Committee of the Board of Directors of the Company. The following table sets forth the number of performance shares that were granted to the Company's Chief Executive Officer, Acting Principal Financial Officer, and the other executive officer of the Company for whom compensation disclosure was required in the Company's most recent proxy statement filed with the Securities and Exchange Commission.

Name and Position

	Number of Performance Shares
Anthony J. Best, President and Chief Executive Officer	23,359
Mark T. Solomon, Controller and Acting Principal Financial Officer	3,392
Milam Randolph Pharo, Vice President—Land and Legal and Assistant Secretary	5,079

The performance shares represent the right to receive, upon settlement of the award after completion of the performance period, a number of shares of the Company's common stock that may be from zero (0) to two (2.0) times the number of performance shares granted on the award date, depending on the extent to which the Company's performance criteria have been achieved and the extent to which the performance shares have vested.

The performance criteria for the calculation of the actual number of shares to be issued upon settlement of the award is a combination of (i) the absolute measure of the cumulative total shareholder return ("TSR") and the associated compound annual growth rate ("CAGR") of the Company for the performance period, and (ii) the relative measure of the Company's TSR and CAGR for the performance period compared with the cumulative TSR and CAGR of the Company's peer companies for the performance period, as reflected in a peer group index. The performance criteria is reflected in a payout matrix, which is used to determine the final number of shares, if any, to be awarded to a 2008 PSA recipient and is attached to the Performance Share Award Agreement, a form of which is filed as Exhibit 10.4 hereto (the "PSA Agreement").

The performance period for the 2008 PSAs began on July 1, 2008 and ends on June 30, 2011. The performance shares granted in the 2008 PSAs will vest 1/7th on August 1, 2009, 2/7th on August 1, 2010, and 4/7th on August 1, 2011. Except as described below, earned shares from the 2008 PSAs will settle on or about August 1, 2011.

Except under certain circumstances described in the PSA Agreement, if a 2008 PSA recipient ceases to be an employee of the Company prior to the vesting of all of the performance shares awarded in the 2008 PSA, any remaining unvested performance shares under the 2008 PSA shall be forfeited.

In the event of a Change of Control Termination (as defined in the PSA Agreement) with respect to a 2008 PSA recipient's employment with the Company that occurs within thirty months of a Change of Control (as defined in the Plan) of the Company and prior to the normal completion of vesting of the performance shares at the end of the performance period, the performance shares of such 2008 PSA recipient shall become fully vested. In such case, the performance period used to determine the extent to which the performance criteria have been achieved shall be shortened to end as of the effective date of the Change of Control, and any shares that such 2008 PSA recipient has earned shall be settled in shares or in cash of equivalent value within thirty days following the effective date of the Change of Control Termination.

The foregoing description of the PSA Agreements does not purport to be complete and is qualified in its entirety by reference to the form of PSA Agreement, a copy of which is filed as Exhibit 10.4 hereto and incorporated herein by reference. A form of the Performance Share Award Notice to participants is filed as Exhibit 10.5 hereto and is incorporated herein by reference.

ITEM 6. EXHIBITS

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

Exhibit	Description
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 (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008).
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).
10.3†	2006 Equity Incentive Compensation Plan As Amended and Restated as of March 28, 2008 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on May 27, 2008).
10.4*†	St. Mary Land & Exploration Company Performance Share Award Agreement.
10.5*†	St. Mary Land & Exploration Company Performance Share Award Notice.
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
99.1*	Press release of St. Mary Land & Exploration Company dated August 4, 2008.

* Filed with this report.
** Furnished with this report.
† Exhibit constitutes a management contract or compensatory plan or agreement.

SIGNATURES

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

ST. MARY LAND & EXPLORATION COMPANY

August 5, 2008	By:/s/ ANTHONY J. BEST Anthony J. Best President and Chief Executive Officer
August 5, 2008	By:/s/ MARK T. SOLOMON Mark T. Solomon Controller and Acting Principal Financial Officer