ST MARY LAND & EXPLORATION CO
Form 10-Q
November 04, 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 September 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).

Yeso 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 October 28, 2008, the registrant had 62,191,539 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	September 30, 2008	December 31, 2007
Current assets:		
Cash and cash equivalents	$ 5,396	$ 43,510
Short-term investments	1,012	1,173
Accounts receivable, net of allowance for doubtful accounts of $16,739 in 2008 and $152 in 2007	182,598	159,149
Refundable income taxes	4,583	933
Prepaid expenses and other	18,598	14,129
Accrued derivative asset	48,155	17,836
Deferred income taxes	26,187	33,211
Total current assets	286,529	269,941
Property and equipment (successful efforts method), at cost:		
Proved oil and gas properties	3,134,922	2,721,229
Less - accumulated depletion, depreciation, and amortization	(927,895)	(804,785)
Unproved oil and gas properties, net of impairment allowance of $9,903 in 2008 and $10,319 in 2007	166,916	134,386
Wells in progress	149,009	137,417
Oil and gas properties held for sale less accumulated depletion, depreciation, and amortization	25,653	76,921
Other property and equipment, net of accumulated depreciation of $13,154 in 2008 and $11,549 in 2007	9,959	9,230
	2,558,564	2,274,398
Other noncurrent assets:		
Goodwill	9,452	9,452
Accrued derivative asset	6,934	5,483
Other noncurrent assets	12,049	12,406
Total other noncurrent assets	28,435	27,341
Total Assets	$ 2,873,528	$ 2,571,680
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 348,549	$ 254,918
Accrued derivative liability	118,314	97,627

Deposit associated with oil and gas properties held for sale		-		10,000
Total current liabilities		466,863		362,545
Noncurrent liabilities:				
Long-term credit facility		170,000		285,000
Senior convertible notes		287,500		287,500
Asset retirement obligation		101,346		96,432
Asset retirement obligation associated with oil and gas properties held for sale		4,087		8,744
Net Profits Plan liability		258,307		211,406
Deferred income taxes		343,046		257,603
Accrued derivative liability		224,870		190,262
Other noncurrent liabilities		8,599		8,843
Total noncurrent liabilities		1,397,755		1,345,790
Commitments and contingencies				
Stockholders' equity:				
Common stock, $0.01 par value: authorized - 200,000,000 shares;				
issued: 62,360,826 shares in 2008 and 64,010,832 shares in 2007;				
outstanding, net of treasury shares: 62,183,839 shares in 2008				
and 63,001,120 shares in 2007		624		640
Additional paid-in capital		91,503		170,070
Treasury stock, at cost: 176,987 shares in 2008 and 1,009,712 shares in 2007		(2,011)		(29,049)
Retained earnings		1,090,059		878,652
Accumulated other comprehensive loss		(171,265)		(156,968)
Total stockholders' equity		1,008,910		863,345
Total Liabilities and Stockholders' Equity	$	2,873,528	$	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 September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Operating revenues and other income:				
Oil and gas production revenue	$ 358,508	$ 228,497	$ 1,068,901	$ 638,357
Realized oil and gas hedge gain (loss)	(53,491)	10,173	(145,837)	36,160
Marketed gas system revenue	24,219	7,414	65,415	31,240
Gain (loss) on sale of proved properties	(4,992)	-	54,063	-
Other revenue	(156)	603	590	9,090
Total operating revenues and other income	324,088	246,687	1,043,132	714,847
Operating expenses:				
Oil and gas production expense	72,724	54,970	205,825	157,618
Depletion, depreciation, amortization and asset retirement obligation liability accretion	72,362	59,061	219,070	162,677
Exploration	10,669	12,562	42,378	42,655
Impairment of proved properties	564	-	10,130	-
Abandonment and impairment of unproved properties	1,231	937	4,295	3,886
General and administrative	24,145	15,805	67,149	44,962
Bad debt expense	6,650	-	16,592	-
Change in Net Profits Plan liability	(34,867)	3,143	46,901	6,948
Marketed gas system expense	22,960	7,278	60,918	29,454
Unrealized derivative (gain) loss	(4,429)	(2,880)	802	2,224
Other expense	7,753	460	9,155	1,577
Total operating expenses	179,762	151,336	683,215	452,001
Income from operations	144,326	95,351	359,917	262,846
Nonoperating income (expense):				
Interest income	239	355	395	612
Interest expense	(5,359)	(4,082)	(15,858)	(13,885)
Income before income taxes	139,206	91,624	344,454	249,573
Income tax expense	(51,159)	(33,971)	(126,861)	(92,735)
Net income	$ 88,047	$ 57,653	$ 217,593	$ 156,838
	62,187	63,424	62,254	61,364

Basic weighted-average common shares outstanding								
Diluted weighted-average common shares outstanding		63,078		64,727		63,327		64,917
Basic net income per common share	$	1.42	$	0.91	$	3.50	$	2.56
Diluted net income per common share	$	1.40	$	0.89	$	3.44	$	2.43

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

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ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME
(UNAUDITED)
(In thousands, except share amounts)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Treasury Stock Shares	Treasury Stock Amount	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	-	-	-	-	-	217,593	-	217,593
Change in derivative instrument fair value	-	-	-	-	-	-	(51,474)	(51,474)
Reclassification to earnings	-	-	-	-	-	-	37,176	37,176
Minimum pension liability adjustment	-	-	-	-	-	-	1	1
Total comprehensive income								203,296
Cash dividends, $ 0.10 per share	-	-	-	-	-	(6,186)	-	(6,186)
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, net of shares used for tax withholdings	413,500	4	(6,484)	-	-	-	-	(6,480)

Sale of common stock, including income tax benefit of stock option exercises	860,330	9	21,020	-	-	-	-	21,029
Stock-based compensation expense	3,750	-	9,555	23,113	922	-	-	10,477
Balances, September 30, 2008	62,360,826	$ 624	$ 91,503	(176,987)	$ (2,011)	$ 1,090,059	$ (171,265)	$ 1,008,910

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

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

	For the Nine Months Ended September 30, 2008	2007
Cash flows from operating activities:		
Reconciliation of net income to net cash provided by operating activities:		
Net income	$ 217,593	$ 156,838
Adjustments to reconcile net income to net cash provided by operating activities:		
Loss related to hurricanes	6,980	-
(Gain) loss on insurance settlement	1,600	(6,340)
Gain on sale of proved properties	(54,063)	-
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	219,070	162,677
Bad debt expense	16,592	-
Exploratory dry hole expense	6,583	12,714
Impairment of proved properties	10,130	-
Abandonment and impairment of unproved properties	4,295	3,886
Unrealized derivative loss	802	2,224
Change in Net Profits Plan liability	46,901	6,948
Stock-based compensation expense*	10,477	8,606
Deferred income taxes	101,231	79,289
Other	(3,496)	(5,168)
Changes in current assets and liabilities:		
Accounts receivable	(39,455)	(208)
Refundable income taxes	(3,650)	4,587
Prepaid expenses and other	2,029	28,035
Accounts payable and accrued expenses	34,763	27,552
Excess tax benefit from the exercise of stock options	(10,281)	(7,658)
Net cash provided by operating activities	568,101	473,982
Cash flows from investing activities:		
Proceeds from insurance settlement	-	7,064
Proceeds from sale of oil and gas properties	155,203	324
Capital expenditures	(494,492)	(500,111)
Acquisition of oil and gas properties	(83,433)	(32,650)
Deposits for acquisition of oil and gas assets	-	(15,310)
Deposits to short-term investments	161	(1,153)
Receipts from short-term investments	-	1,450
Other	(9,984)	29

Net cash used in investing activities		(432,545)		(540,357)
Cash flows from financing activities:				
Proceeds from credit facility		832,000		553,914
Repayment of credit facility		(947,000)		(732,914)
Repayment of short-term note payable		-		(4,469)
Excess tax benefit from the exercise of stock options		10,281		7,658
Net proceeds from issuance of senior convertible debt		-		280,664
Proceeds from sale of common stock		11,327		6,342
Repurchase of common stock		(77,202)		(25,904)
Dividends paid		(3,076)		(3,140)
Net cash provided by (used in) financing activities		(173,670)		82,151
Net change in cash and cash equivalents		(38,114)		15,776
Cash and cash equivalents at beginning of period		43,510		1,464
Cash and cash equivalents at end of period	$	5,396	$	17,240

* 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 September 30, 2008, and 2007, respectively,
approximately $3.8 million and $2.6 million of stock-based compensation expense was included in exploration expense.
During the periods ended September 30, 2008, and 2007, respectively, approximately $6.7 million and $6.0 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 Nine Months Ended September 30,	
	2008	2007
	(in thousands)	
Cash paid for interest	$ 14,483	$ 13,476
Cash paid or (refunded) for income taxes	$ 18,943	$ (1,048)

Dividends of approximately $3.1 million have been declared by the Company's Board of Directors, but not paid, as of September 30, 2008.

In September 2008, the Company hired a new senior executive. Upon commencement of employment, the Company issued 15,496 shares of restricted stock awards to the senior executive, of which half will vest on December 15, 2009 and the remaining half to vest on December 15, 2010, provided on such vesting dates the executive is employed by the Company. The total fair value of the issuance was $600,005.

In August 2008 the Company issued 465,751 Performance Share Awards to employees as equity-based compensation pursuant to the Company's 2006 Equity Incentive Compensation Plan. The total fair value of the issuance equaled $12.3 million.

During the first nine months of 2008 and 2007, the Company issued 427,607 and 98,664 restricted stock units to employees as equity-based compensation, respectively, pursuant to the Company's 2006 Equity Incentive Compensation Plan. The total fair value of the issuances were $23.3 million and $3.1 million, respectively.

As of September 30, 2008, and 2007, $159.5 million and $102.6 million, respectively, are included in the balances of oil and gas properties and 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 $922,000 and $855,000 for the nine-month periods ended September 30, 2008, and 2007, respectively.

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 achieved certain performance metrics. The total fair value of these issuances were $141,900 and $45,012, 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.

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

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

September 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 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 classified as exploration expense. The entire impact of this change 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 common share, or diluted net income per common share, as it was simply a reclassification between two line items within the accompanying consolidated statements of operations. Refer to Note 14 of Part II, Item 8 within the Form 10-K/A for the year ended December 31, 2007, for further discussion.

Other Significant Accounting Policies

The accounting policies followed by the Company are set forth in Note 1 to the Company's consolidated financial statements in the Form 10-K/A for the year ended December 31, 2007, and are supplemented throughout the footnotes of this document. It is suggested that these unaudited condensed consolidated financial statements be read in conjunction with the consolidated financial statements and notes included in the Form 10-K/A for the year ended December 31, 2007.

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

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 $21.7 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 $697,000 and may be impacted by the previously mentioned post-closing adjustments. The Company determined that this sale does not qualify for discontinued operations accounting under Financial Accounting Standards Board ("FASB") Emerging Issues Task Force Issue No. 03-13 ("EITF No. 03-13").

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 fourth quarter of 2008. The estimated gain on sale of proved properties related to the divestiture is approximately $55.7 million and may be impacted by the previously mentioned post-closing adjustments. The Company determined that this sale does not qualify for discontinued operations accounting under EITF No. 03-13. These assets were classified as assets held for sale as of December 31, 2007.

Williston Basin Acquisition

On August 13, 2008, the Company acquired oil and gas properties located in the Bakken and Three Forks formations in the Williston Basin for $20.2 million of cash. After normal purchase price adjustments, the Company allocated $3.6 million to proved oil and gas properties and $16.6 million to unproved oil and gas properties. The Company also recorded $56,000 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. The final purchase price is subject to normal post-closing adjustments and is expected to be finalized during the fourth quarter of 2008.

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.

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 $149.0 million. After normal purchase price adjustments, the Company allocated $127.3 million to proved oil and gas properties, $23.1 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. The acquisition was funded with cash on hand and borrowings under the Company's existing

credit facility. The acquired properties are 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 risked natural gas liquids production related to this acquisition.

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.

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 Internal Revenue Service ("IRS") 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. On September 12, 2008, the reverse like-kind exchange was completed and SMA, LLC, became a wholly owned subsidiary of St. Mary. Subsequent to September 30, 2008, the Carthage Field assets were transferred to St. Mary by merger. As of the filing date of this report, SMA, LLC is inactive and does not hold any assets and its status with the Secretary of State of Texas has been terminated.

From the date of closing the Carthage acquisition on March 21, 2008, through October 10, 2008, the assets held by SMA, LLC, were leased by St. Mary under a triple net lease whereby St. Mary had the benefits and risks of all revenues and costs attributed to the properties. The Carthage assets were 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 Incorporated as qualified intermediary in this transaction. On September 12, 2008, the funds from this transaction were moved into the Company's operating cash account upon completion of the like-kind 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 provision of FASB Interpretation No. 46(R), "Consolidation of Variable Interest Entities" ("FIN 46(R)"), the Company determined that SMA, LLC was a variable interest entity for which St. Mary was 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 loan to SMA, LLC was repaid subsequent to September 30, 2008.

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 IRS 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

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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 provision of FIN 46(R), the Company determined that SMLEA, LLC is a variable interest entity for which St Mary is the primary beneficiary. Accordingly, SMLEA, LLC was consolidated into St. Mary subsequent to the completion of the purchase of oil and gas properties on October 4, 2007. As a result of the consolidation, St. Mary recognized all oil and gas reserves and production as well as all revenues and expenses attributed to the Rockford acquisition beginning on October 4, 2007. The loan to SMLEA, LLC was repaid on February 7, 2008.

Assets Held for Sale

As of September 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 accompanying consolidated balance sheet at the lower of carrying value or fair value less the cost to sell. The accompanying consolidated balance sheet as of September 30, 2008, presents $25.7 million of assets held for sale, net of accumulated depletion, depreciation and amortization. Assets held for sale were measured at carrying value, which was less than fair value less cost to sell as of September 30, 2008. Subsequent changes to fair value less the cost to sell will impact the measurement of assets held for sale if the fair value is determined to be less than the carrying value of the assets. Asset retirement obligation liabilities of $4.1 million related to these properties have also been reclassified to liabilities associated with oil and gas properties held for sale on the consolidated balance sheet as of September 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, Performance Share Awards (“PSAs”), 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

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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. There were no potentially dilutive shares related to the 5.75% Senior Convertible Notes included in the diluted earnings per share calculation for the three-month and nine-month periods ended September 30, 2008. Approximately 2.1 million potentially dilutive shares related to the 5.75% Senior Convertible Notes were included in the diluted earnings per share calculation for the nine-month period ended September 30, 2007. There were no potentially dilutive shares related to the 5.75% Senior Convertible Notes included in the diluted earnings per share calculation for the three-month period ended September 30, 2007.

The Company's 3.50% Senior Convertible Notes, which were issued April 4, 2007, have a net-share settlement right whereby each $1,000 principal amount of notes may be surrendered for conversion for cash in an amount equal to the principal amount and, if applicable, shares of common stock for the amount in excess of the principal amount. 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 nine-month periods ended September 30, 2008, and 2007.

On August 1, 2008, the Company granted 465,751 PSAs for the three-year performance period ended July 31, 2011. At the end of each grant's three-year performance period, a multiplier will be applied to all vested PSAs to determine the number of common shares issued. The number of common shares issued is contingent upon the satisfaction of certain market conditions. The number of potentially dilutive shares related to the PSAs is based on the number of shares, if any, which would be issuable if the end of the reporting period were the end of the contingency period. There were no potentially dilutive shares related to the PSAs included in the diluted earnings per share calculation for the three-month and nine-month periods ended September 30, 2008. We refer you to Note 5 – Compensation Plans for additional information regarding PSAs.

The treasury stock method is used to measure the dilutive impact of stock options, RSUs, and PSAs. The dilutive effect of stock options and unvested RSUs is considered in the detailed calculation below. The RSU transitional awards granted on June 30, 2008, are anti-dilutive for the nine-month period ended September 30, 2008. There were no anti-dilutive securities related to stock options, RSUs, or PSAs for the three-month period ended September 30, 2008, and the three-month and nine-month periods ended September 30, 2007.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
	(In thousands, except per share amounts)			
Net Income	$ 88,047	$ 57,653	$ 217,593	$ 156,838
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	-	-	-	(471)
Net income adjusted for the effect of dilution	$ 88,047	$ 57,653	$ 217,593	$ 157,638
Basic weighted-average common stock outstanding	62,187	63,424	62,254	61,364
Add: dilutive effect of stock options and unvested RSUs	891	1,303	1,073	1,471
Add: dilutive effect of 5.75% Convertible Notes using if-converted method	-	-	-	2,082
Diluted weighted-average common shares outstanding	63,078	64,727	63,327	64,917
Basic net income per common share	$ 1.42	$ 0.91	$ 3.50	$ 2.56
Diluted net income per common share	$ 1.40	$ 0.89	$ 3.44	$ 2.43

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. 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 are then further refined by individual performance. The Company accrues cash bonus expense based upon the current year's performance. In February 2008 the Company paid $3.5 million for cash bonuses earned in the 2007 performance year and in February 2007 paid $1.8 million earned in the 2006 performance year. Included in the general and administrative and exploration expense line items in the accompanying consolidated statements of operations is the cash bonus expense related to the specific performance year of $2.7 million and $1.3 million for the three-month periods ended September 30, 2008, and 2007, respectively. Total cash bonus expense for the nine-month periods ended September 30, 2008, and 2007, was $7.2 million, and $3.8 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 the 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 provision 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 provision of SFAS No. 123(R).

As of September 30, 2008, approximately 1.5 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 approved by the Company's stockholders at the 2008 annual stockholders' meeting held on May 21, 2008. For an 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. The issuance of a PSA is considered a direct share benefit under the 2006 Equity Plan. At the end of each grant's three-year performance period a multiplier ranging between zero and two is applied to each performance share so that each performance share granted has the potential to result in the issuance of two shares of common stock. Consequently, each performance share granted counts as four shares against the number of shares available to be granted under the 2006 Equity Plan. Stock options granted count as one share for each instruments issued against the number of shares available to be granted under the 2006 Equity Plan.

The Company does have outstanding stock option grants under the Predecessor Plans and RSU awards under both the Predecessor Plans and the 2006 Equity Plan. The following sections describe the details of RSU grants, stock options, and PSAs outstanding as of September 30, 2008.

Performance Share Awards

In late 2007 St. Mary transitioned to PSA grants as the primary form of long-term equity incentive compensation for eligible employees in place of grants of RSUs and the awarding of interests in the Net Profits Plan. On August 1, 2008, the Company granted 465,751 PSAs. PSAs represent the right to receive, upon settlement of the PSAs after the completion of three-year performance period ending July 31, 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. The number of shares issued depends 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 periods 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, 2/7 ths August 1, 2010, and 4/7ths on August 1, 2011.

Total stock-based compensation expense related to PSAs for both the three-month and nine-month periods ended September 30, 2008, was $789,000. There was no stock-based compensation expense related to PSAs for the three-month and nine-month periods ended September 30, 2007.

In measuring compensation expense related to the grant of PSAs, SFAS No. 123(R) requires companies to estimate the fair value of the award on the grant date. The fair value of PSAs has been measured under a stochastic process method using the Geometric Brownian Motion Model ("GBM Model"). A stochastic process is a mathematically defined equation that can create a series of outcomes over time. These outcomes are not deterministic in nature, which means that by iterating the equations

multiple times, different results will be obtained for those iterations. In the case of the Company's PSAs, the Company cannot predict with certainty the path its stock price or the stock price of its peers will take over the three-year performance period. By using a stochastic simulation the Company can create multiple prospective stock pathways, statistically analyze these simulations, and ultimately make inferences to the most likely path the stock price will take. As such, because future stock prices are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the GBM Model, is deemed an appropriate method by which to determine the fair value of the PSAs. The fair value of the Company's PSAs granted on August 1, 2008, was $12.3 million.

A summary of the status and activity of PSAs for the nine-month period ended September 30, 2008, is presented in the following table.

	PSAs		Weighted-Average Grant-Date Fair Value
At January 1, 2008	-	$	-
Granted	465,751	$	26.48
Vested	-	$	-
Forfeited	(518)	$	26.48
At September 30, 2008	465,233	$	26.48

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 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 18,986 and 20,007 RSUs for various grants to certain employees during the nine-month periods ended September 30, 2008, and 2007, respectively. These grants have various vesting periods. The total fair value associated with these issuances was $726,000 in 2008 and $643,000 in 2007 as measured on the respective grant dates.

St. Mary issued 265,373 RSUs on June 30, 2008, as a transitional award between the old RSU program and the new PSA program. The total fair value associated with this issuance was $17.2 million as measured on the grant date. One third of the granted RSUs vests on December 15th in 2008, 2009, and 2010, respectively. 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 for existing awards in 2007 within the safe harbor adoption provisions of the newly enacted U.S. Treasury regulations interpreting the IRC provisions 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 by mutual election, and as such the incremental value associated with the removal of 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 September 30, 2008, a total of 500,942 RSUs were outstanding, of which 7,091 were vested. The total RSU compensation expense for the three-month periods ended September 30, 2008, and 2007, was $3.2 million and $2.1 million, respectively, and the total RSU compensation expense for the nine-month periods ended September 30, 2008, and 2007, was $9.3 million and $7.1 million, respectively. As of September 30, 2008, there was $15.7 million of total unrecognized compensation expense related to unvested RSU awards. The unrecognized compensation expense is being amortized through 2011.

During the first three quarters of 2008, the Company has converted 587,437 RSUs, which relate to those awards granted in 2008, 2007, and 2006, into common stock based on the amended 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 the award agreements. As a result, the Company issued net 413,500 shares of common stock associated with these grants. The remaining 173,937 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon the delivery of the shares underlying those RSUs.

During the first three quarters of 2007, the Company converted 427,059 RSUs, which related to the awards granted in 2004, 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 the award agreements. As a result, the Company issued net 302,370 shares of common stock associated with these grants. The remaining 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 RSU awards granted in the nine-month period ended September 30, 2007 were estimated using the following weighted-average assumptions:

	September 30, 2007
Risk free interest rate:	4.6%
Dividend yield:	0.3%
Volatility factor of the market price of the Company's common stock:	32.2%
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 award 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 fair value of these issuances was $141,900 and $45,012 respectively.

A summary of the status and activity of non-vested RSUs for the nine-month period ended September 30, 2008, is presented in the following table.

	RSUs		Weighted-Average Grant-Date Fair Value
Non-vested, at January 1, 2008	289,385	$	32.26
Granted	443,103	$	53.87
Vested	(200,899)	$	32.43
Forfeited	(37,738)	$	37.62
Non-vested, at September 30, 2008	493,851	$	50.97

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.

There was no stock-based compensation expense for the three-month period ended September 30, 2008, related to stock options that were outstanding and unvested as of January 1, 2006. Total stock-based compensation related to these stock options equaled $27,000 for the three-month period ended September 30, 2007. The total stock-based compensation expense related to stock options for the nine-month periods ended September 30, 2008, and 2007, was $17,000 and $409,000, respectively. There was no cumulative effect adjustment for the adoption of SFAS No. 123(R). As of September 30, 2008, there were no unvested stock options outstanding.

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 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 $10.3 million and $7.7 million of excess tax benefits for the nine-month periods ended September 30, 2008, and 2007, respectively, as cash inflows from financing activities. Cash received from option exercises for the nine-month periods ended September 30, 2008, and 2007, equaled $10.7 million and $5.9 million, respectively.

The following table summarizes the nine-month activity for stock options outstanding as of September 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	(860,330)	$ 12.49		
Forfeited	-	$ -		
Outstanding, end of period	1,525,170	$ 12.69	3.89	$ 35,024
Vested, or expect to vest end of period	1,525,170			$ 35,024
Exercisable, end of period	1,525,170	$ 12.69	3.89	$ 35,024

As of September 30, 2008, there was no unrecognized compensation cost related to unvested stock option awards.

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 an active compensation program from 1991 through 2007. Pool years prior to and including 2005 are fully vested. The 2006 and 2007 pool years are subject to a vesting schedule and include a cap whereby the maximum benefits 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 was designed to replace the 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 was 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 with 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. Of the payments made under the Net Profits Plan, 11 percent and 23 percent would have been classified as exploration expense in the accompanying consolidated statements of operations for the three-month periods ended September 30, 2008, and 2007, respectively. Of the payments made under the Net Profits Plan, 33 percent and 22 percent would have been classified as exploration expense in the accompanying consolidated

statements of operations for the nine-month periods September 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 who have terminated employment and therefore do not provide ongoing exploration support.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
	(In thousands)			
General and administrative expense	$ (30,965)	$ 2,406	$ 31,347	$ 5,431
Exploration expense	(3,902)	737	15,554	1,517
Total	$ (34,867)	$ 3,143	$ 46,901	$ 6,948

Note 6 – Income Taxes

Income tax expense for the three-month and nine-month periods ended September 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 September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
	(In thousands)			
Current portion of income tax expense:				
Federal	$ 5,415	$ 6,512	$ 24,155	$ 11,494
State	509	627	1,475	1,952
Deferred portion of income tax expense:	45,235	26,832	101,231	79,289
Total income tax expense	$ 51,159	$ 33,971	$ 126,861	$ 92,735
Effective tax rates	36.8%	37.1%	36.8%	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 $3.1 million refund of income tax and interest from a carryback of net operating losses to the 2000 tax year. An additional $980,000 was received in the first quarter of 2008 for income tax refunds and accrued interest resulting from a carry-over of minimum tax credits to the 2003 tax year. These amounts have been previously recognized by the Company. The Internal Revenue Service initiated an audit of the Company's 2005 tax year that began on April 24, 2008, and is ongoing.

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

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adoption. At adoption, the Company had a long-term liability for an 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 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 and non-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 $500 million 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 $170.0 million and $198.0 million outstanding under its revolving credit agreement as of September 30, 2008, and October 28, 2008, respectively. The Company had $330 million and $302 million of available borrowing capacity under this facility as of September 30, 2008, and October 28, 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.

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 the Company will pay the following to holders for each $1,000 principal amount of notes converted 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 $271 million as of September 30, 2008.

Weighted-Average Interest Rate Paid and Capitalized Interest Costs

The weighted-average interest rates paid for the three-month periods ended September 30, 2008, and 2007, were 4.4 percent and 5.1 percent, respectively, including commitment fees paid on the unused portion of the credit facility aggregate commitment, amortization of deferred financing costs, amortization of the contingent interest embedded derivative associated with the 5.75% Senior Convertible Notes for 2007, and the effect of interest rate swaps. The weighted-average interest rates paid for the nine-month periods ended September 30, 2008, and 2007, were 4.7 percent and 5.9 percent, respectively. The outstanding loan balance as of September 30, 2008, increased in comparison to the outstanding loan balances as of September 30, 2007, while the three-month and nine-month period rates associated with the balances decreased. The decrease is attributed to significantly lower LIBOR and Prime rates for the specified periods in 2008 compared to 2007. Capitalized interest costs for the three-month period ended September 30, 2008, and 2007, were $751,000 and $1.2 million, respectively. Additionally, capitalized interest costs for the nine-month period ended September 30, 2008, and 2007, were $2.8 million and $3.8 million, respectively.

Note 8 – Derivative Financial Instruments

Oil and Natural 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 September 30, 2008, the Company has hedge contracts in place through 2011 for a total of approximately 9 million Bbls of anticipated crude oil production, 64 million MMBtu of anticipated natural gas production, and 1 million Bbls of anticipated natural gas liquids production.

The Company attempts to qualify its oil, natural gas, and natural gas liquids 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, natural gas, or natural gas liquids 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 September 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 $288.1 million at September 30, 2008. The Company realized a net loss of $53.5 million and a net gain of $10.2 million from its oil and natural gas derivative contracts for the three-month periods ended September 30, 2008, and 2007, respectively. The Company realized a net loss of $145.8 million and a net gain of $36.2 million from its oil and natural gas derivative contracts for the nine-month periods ended September 30, 2008, and 2007, respectively.

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At September 30, 2008, the Company had no margin collateral deposits with hedge counterparties. As of December 31, 2007, the Company had $2.0 million 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 counterparty to the Company's hedges is not a participant in the Company's credit facility agreement, and this counterparty requires a dollar for dollar margin to be posted as collateral for mark-to-market liabilities that 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 September 30, 2008, the amount of unrealized loss, net of unrealized gains and net of deferred income taxes, to be reclassified from accumulated other comprehensive income to oil and natural gas production operating revenues in the next twelve months is equal to $64.9 million.

Any change in fair value resulting from ineffectiveness is recognized currently in unrealized derivative gain (loss) in the accompanying consolidated statements of operations. Unrealized derivative gain (loss) for the three-month periods ended September 30, 2008, and 2007, includes net gains of $4.4 million and $2.9 million respectively, from ineffectiveness related to oil and natural gas derivative contracts. Unrealized derivative gain (loss) for both the nine-month periods ended September 30, 2008, and 2007, includes net losses of $800,000 and $2.2 million, respectively, from ineffectiveness related to oil and natural gas derivative contracts.

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
	(In thousands)			
Derivative contract settlements included in oil and gas hedge gain (loss)	$ (53,491)	$ 10,173	$ (145,837)	$ 36,160
Ineffective portion of hedges qualifying for hedge accounting included in derivative gain (loss)	4,429	4,336	(802)	(889)
Non-qualifying derivative contracts included in derivative gain (loss)	-	(1,456)	-	(1,335)
Interest rate derivative contract settlements included in interest expense	(476)	-	(1,017)	(283)
Total gain (loss)	$ (49,538)	$ 13,053	$ (147,656)	$ 33,653

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 the 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 nine-month period ended September 30, 2007. There was no net derivative loss recorded in interest expense for the three-month period ended September 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 paid a fixed rate of 4.9 percent and was paid a variable rate based on the one-month LIBOR rate. The interest rate derivative contract was measured at fair value using quoted prices in active markets. The interest rate swap was a highly liquid, non-complex, non-structured instrument. This derivative qualified for cash flow hedge treatment under SFAS No. 133 and related pronouncements. The Company recorded net derivative losses in interest expense of $476,000 and $1.0 million in the accompanying consolidated statements of operations for the three-month and nine-month periods ended September 30, 2008, respectively, related to the interest rate derivative contract. This instrument was settled in the third quarter of 2008.

The contingent interest provision of the 3.50% Senior Convertible Notes is a derivative instrument. As of September 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 September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
	(In thousands)			
Service cost	$ 460	$ 478	$ 1,379	$ 1,433
Interest cost	222	198	665	595
Expected return on plan assets	(168)	(135)	(503)	(405)
Amortization of net actuarial loss	40	55	121	164
Net Periodic benefit cost	$ 554	$ 596	$ 1,662	$ 1,787

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 $2.5 million to the Qualified Pension Plan during the first three quarters of 2008. Presently, the Company believes it will contribute an additional $300,000 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

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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 estimated economic lives, historical experience in abandoning wells, estimated 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 September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
	(In thousands)			
Beginning asset retirement obligation	$ 106,486	$ 90,554	$ 108,284	$ 77,242
Liabilities incurred	1,073	2,702	7,162	7,443
Liabilities settled	(4,039)	(3,380)	(16,509)	(4,678)
Accretion expense	1,954	1,465	5,337	4,215
Revision to estimated cash flow	6,373	651	7,573	7,770
Ending asset retirement obligation	$ 111,847	$ 91,992	$ 111,847	$ 91,992

Accounts payable and accrued expenses contain $6.4 million and $6.9 million related to the Company's current asset retirement obligation liability as of September 30, 2008, and 2007, respectively. Accounts payable and accrued expenses contain $3.1 million related to the Company's current asset retirement obligation liability as of December 31, 2007. As of September 30, 2008, September 30, 2007, and December 31, 2007, the accounts payable and accrued expenses balances include amounts for the estimated retirement costs associated with an off-shore platform that was destroyed during Hurricane Rita in 2005. Retirement of the platform was substantially completed as of September 30, 2008. Please refer to Note 13 – Insurance Settlement for additional details. Additionally, the September 30, 2008, amount includes an accrual in excess of the Company's maximum insurance policy limit for the remediation of the Vermilion 281platform and other properties damaged in Hurricane Ike in September 2008.

Note 11 – Fair Value Measurements

Effective January 1, 2008, the Company partially 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 exact 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

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- Level 2 – Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable

- Level 3 – Significant inputs to the valuation model are unobservable

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

	Level 1	Level 2	Level 3
		(In thousands)	
Assets:			
Accrued derivative	$ -	$ 55,089	$ -
Liabilities:			
Accrued derivative	$ -	$ 343,184	$ -
Net Profits Plan	$ -	$ -	$ 258,307

A financial asset or liability is categorized within the hierarchy based on 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 ratings, 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 market place 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 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, and 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 as of September 30, 2008.

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 liquids 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, 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 derivative assets and liabilities are classified as having Level 2 inputs.

Interest Rate Derivative Assets and Liabilities – The Company had one interest rate swap agreement in place for the notional amount of $75 million, which was settled in the third quarter of 2008. This instrument effectively caused a portion of the Company's floating rate debt to become fixed rate debt and was held with a major financial institution. A mark-to-market valuation that took 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 was used to value the swap. Given the degree of varying assumptions used to value the swap, it was deemed to use Level 2 inputs.

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 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. This rate 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 the price that is derived from a rolling average of actual prices realized of the prior 24 months together with adjusted New York Mercantile Exchange ("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 rate, 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 September 30, 2008, would differ by approximately $30 million. A one percentage point decrease in the discount rate would result in an increase to the liability of approximately $15 million, while a one percentage point increase in the discount rate would result in a decrease to the liability of approximately $14 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 nine-month periods ended September 30, 2008:

	For the Three Months Ended September 30, 2008	For the Nine Months Ended September 30, 2008
	(In thousands)	
Beginning balance	$ 293,174	$ 211,406
Net increase (decrease) in liability(a)	(24,451)	92,832
Net settlements (a)(b)	(10,416)	(45,931)
Transfers in (out) of Level 3	-	-
Ending balance	$ 258,307	$ 258,307

(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 under the Net Profits Plan.

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 September 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 second or third quarters of 2008.

St. Mary repurchased 790,816 shares of common stock under the program during the third quarter of 2007 at a weighted-average price of $32.76 per share, including commissions, for a total of $25.9 million. St. Mary did not repurchase any shares of common stock under the program during the first half of 2007.

Note 13 – Insurance Settlement

In April 2007 the Company reached a global insurance settlement for reimbursement of damages sustained during Hurricane Rita in 2005. St. Mary's net amount of the final settlement was approximately $33 million. As a result of this settlement, the company recorded a gain of $6.3 million in other revenue in the accompanying consolidated statement of operations for the nine months ended September 30, 2007. The Company experienced significant weather-related and other delays in its retirement efforts and consequently incurred additional retirement costs for the offshore platform. As of September 30, 2008, the Company has recorded a gain of $3.6 million associated with the insurance settlement. The Company's retirement efforts are substantially complete as of the date of this filing and the Company expects adjustments to the gain to be completed during the fourth quarter of 2008. Any variation between actual and estimated retirement costs will impact the final determination of the gain associated with the insurance settlement.

Note 14 – SemGroup Bankruptcy

On July 22, 2008, SemGroup, L.P. and certain of its North American subsidiaries (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 filing the Company recorded an allowance for doubtful accounts and bad debt expense of $16.6 million as of September 30, 2008, of which $6.7 million was recognized as bad debt expense during the three-month period ended September 30, 2008, and $9.9 million was recognized during the three-month period ended June 30, 2008. The Company believes that it has fully allowed for all potential uncollectible amounts and believes that it has no remaining exposure resulting from this bankruptcy. In an effort to maximize its recovery, the Company has filed the appropriate pleadings and is participating in certain adversary proceedings in the SemGroup bankruptcy case to establish the Company's secured and priority claims. The matter does not have a material adverse effect on the Company's liquidity or overall financial position.

Note 15 – Hurricanes Gustav and Ike

During the third quarter of 2008, assets in which the Company has an interest were impacted by Hurricanes Gustav and Ike. The Company incurred damage to two wells and to its production facilities located at Goat Island in Galveston Bay and minor damages to several other properties. The Vermilion 281 production platform was lost in Hurricane Ike. The Company currently estimates that it will incur $26 million associated with the clean up, assessment of damages, and remediation associated with this platform.

The Company maintains insurance that it expects to utilize with regard to the lost platform and damage to several other properties. Due to the severe damage caused by the hurricane, the Company currently expects the total storm related costs to exceed the maximum insurance policy limit. During the third quarter of 2008, the Company wrote off the carrying value of the Vermilion 281 platform, as well as the carrying value associated with the production facility assets located at Goat Island. Additionally, the Company established an accrual for the estimate of the remediation and various other property damage repair costs the Company expects to incur in excess of its maximum insurance policy limit. As a result, the Company has recorded a $7.0 million loss, which is included in other expense in the accompanying consolidated statement of operations for the third quarter of 2008. Any variation between actual and estimated storm related costs will impact the final determination of the loss.

Note 16 – 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) that categories of assets and liabilities recorded or disclosed at fair value to which the statement was not applied.

The Company adopted FSP No. 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 the 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. Please 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

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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 Standard 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 conversions 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 14-1 changes 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 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 issues 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 is effective November 15, 2008. The FASB does not expect that SFAS No. 162 will cause a change in current practice, and the Company does not believe that SFAS No. 162 will have an impact on its financial statements, financial position, and results of operations or cash flows.

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 our 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 to build value for our stockholders.

Financial Standing and Liquidity

During and subsequent to the third quarter of 2008, specific issues related to the financial sector have rippled through the broader economy. The failure or takeovers of several large financial institutions has adversely impacted the wider equity, debt, and credit markets. Financial standing and liquidity have become increasingly important as concerns have been raised regarding the pace of drilling activity in the exploration and production industry and the ability of companies to fund their planned activity. In addition, fears of global recession have resulted in a significant decline in oil and natural gas prices. Our planned exploration and production capital expenditures budget of $758 million for 2008 is expected to be near our discretionary cash flow for the year. Moreover, we are currently in the process of budgeting for our 2009 exploration and development program, and we expect that program will be at or within our discretionary cash flow for 2009. Accordingly, we do not currently expect to require additional amounts of financing to execute our plans for the remainder of 2008 or during 2009, and we do not anticipate accessing the equity or public debt markets for the remainder of 2008 or during 2009. We have spent $83.4 million on acquisitions and $77.2

million for share repurchases in 2008. However, these have largely been offset by divestitures of non-strategic properties that have provided $155.2 million in proceeds.

We continue to believe we have adequate liquidity available to us through our credit facility. On October 1, 2008, the lending group redetermined our reserve-backed borrowing base under the credit facility at an amount of $1.4 billion. Based on our expected needs, we have elected a $500 million commitment amount. These terms are identical to the terms which were in place in the previous six months prior to the redetermination. We had $170.0 million and $198.0 million, respectively, drawn on the credit facility at September 30, 2008, and October 28, 2008. Management believes that the current commitment is sufficient and that if necessary we could request a higher commitment amount from the lending group, although it would likely be at different terms and interest rates than are currently in place. To date, we have experienced no issues drawing upon our credit facility and all eleven participating banks have continued to fund. No individual bank participating in the credit facility represents more than 11 percent of the lending commitments under the credit facility. We are monitoring the borrowing environment closely and have frequent discussions with the lending group to ensure we are aware of the latest developments. One of the co-lead banks in the credit facility, Wachovia, has agreed to be acquired by the other co-lead bank, Wells Fargo. The transaction is expected to close by year-end, but is not anticipated to result in any changes to the terms of our credit facility.

Oil and Gas Prices

Oil and natural gas prices reached significant highs during June and early July of 2008 and have declined significantly since that time. The results of our operations and financial condition are significantly affected by oil and natural gas commodity prices, which can fluctuate dramatically. We sell a majority of our natural gas under contracts that use first of the month index pricing, which means that 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 either the NYMEX West Texas Intermediate daily settlement or the average of alternative posted prices for the periods in which the crude oil is produced, adjusted for quality, transportation, and location differentials. The following table is a summary of commodity price data for the third and second quarters of 2008 and the third quarter of 2007.

	For the Three Months Ended		
	September 30, 2008	June 30, 2008	September 30, 2007
Crude Oil (per Bbl):			
NYMEX price	$ 117.98	$ 123.98	$ 75.38
Realized price, before the effects of hedging	$ 111.97	$ 120.20	$ 71.68
Net realized price, including the effects of hedging	$ 83.30	$ 88.40	$ 67.56
Natural Gas (per Mcf):			
NYMEX price	$ 10.09	$ 10.80	$ 6.13
Realized price, before the effects of hedging	$ 9.96	$ 10.83	$ 5.98
Net realized price, including the effects of hedging	$ 9.51	$ 9.97	$ 7.03

Average quarterly NYMEX crude oil prices decreased five percent from the second quarter of 2008 to the third quarter of 2008 from $123.98 per barrel to $117.98 per barrel. The price of crude oil is decreasing as a result of a forecasted decrease in global demand, which is a consequence of a broader economic slowdown stemming from the financial turmoil that has taken place in recent months. The 36-month forward strip price for crude oil at the end of the second quarter of 2008 was $139.34 per barrel. At the end of the third quarter of 2008, the 36-month forward contract had decreased by 26 percent to $103.72 per barrel. By October 28, 2008, the 36-month forward strip price had declined an additional 32 percent to $70.40 per barrel.

Average quarterly NYMEX natural gas prices decreased seven percent from the second quarter of 2008 to the third quarter of 2008 from $10.80 per Mcf to $10.09 per Mcf. The 36-month forward strip price for natural gas at the end of the second quarter of 2008 was $11.91 per MMBtu. At the end of the third quarter of 2008, the 36-month forward contract had decreased 30 percent to $8.36 per MMBtu. As of October 28, 2008, the 36-month forward strip price had declined an additional 12 percent to $7.39 per MMBtu. Natural gas prices have been pressured downward in recent months as a result of a forecasted decrease in global demand and over concerns of forecasted excess gas supply that will be generated from significant activity in the exploration and production industry, specifically the ramp up in the number of horizontal wells planned in a number of new shale plays across the United States.

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 differential for these products. We refer to this price as our realized price, which excludes the effects of hedging. We are beginning to see wider differentials for both oil and natural gas in recent months in regions that have high levels of industry activity. In particular, differentials for oil in the Williston Basin have been pressured as activity in the area has accelerated in recent months and differentials for natural gas in the Mid-Continent have widened as regional demand has not kept pace with the growth in supply generated by several successful shale plays in the general vicinity. Our realized price is further impacted by the result of our hedging contracts that are settled in the respective periods. We refer to this price as our net realized price. Our net natural gas price realization for the three months ended September 30, 2008, was negatively impacted by $8.1 million of realized hedge losses and our net oil price realization was negatively impacted by $45.4 million of realized hedge losses. On a percentage basis, we currently have hedged more forecasted crude oil production than forecasted natural gas production using a combination of swaps and costless collars.

Effects of Hurricanes Gustav and Ike

During the third quarter of 2008, assets in which we have an interest were impacted by Hurricanes Gustav and Ike. We lost the Vermilion 281 producing platform in the Gulf of Mexico and incurred damage to our production facilities in Galveston Bay. The most impactful damage caused by the storm was to power and processing facilities and infrastructure in the Gulf Coast area, causing us to shut-in production throughout the Gulf Coast region. Production from certain Gulf Coast properties continues to be shut-in as of the date of this report. Many of the facilities damaged by these storms are involved in the processing and transporting of natural gas and oil produced in areas other than the Gulf Coast or Gulf of Mexico. As a result, we have experienced production disruptions in the Permian, Mid-Continent, and Gulf Coast regions while damaged facilities were repaired. The overall impact from the recent hurricanes in the Gulf of Mexico did not have a material impact on our financial position or results of operations.

As mentioned above, the Vermilion 281 production platform was lost in Hurricane Ike. Our net production from Vermilion 281 was approximately 263 MCFED before the storm, and we had an estimated 382 MMCFE of proved reserves as of September 1, 2008. We are in the process of assessing and remediating the damage related to the Vermilion 281 platform. As of the filing date of this report, we estimate that we will incur $26 million associated with the clean up, assessment of damages, and remediation associated with this platform.

Hurricane Ike caused damage to two wells and our production facilities located at Goat Island in Galveston Bay. Restoration is largely dependent on repairs to our transportation, storage, and processing facilities. As of the filing date of this report, we currently estimate that we will incur a net $1 million to rebuild the production facilities.

We also incurred minor damage to outside-operated properties from the hurricanes. Restoration of the remaining shut-in production is largely dependent on repairs to transportation and processing facilities which are owned and operated by other operators and facility owners.

We maintain insurance that we expect to utilize with regard to the lost platform and repairs to various other properties. Due to the severe damage caused by the hurricane, we currently expect the remediation costs related to the platform and the repairs to various other properties will exceed the maximum insurance policy limit. During the third quarter of 2008, we wrote off the carrying value of the Vermilion 281 platform, as well as the carrying value associated with the production facility assets located at Goat Island. Additionally, we established an accrual for our estimate of the remediation and various other property damage repair costs we expect to incur in excess of our maximum insurance policy limit. As a result, we recorded a $7.0 million loss for the third quarter of 2008, which is included in other expense in the accompanying consolidated statement of operations. Any variation between actual and estimated remediation and damage repair costs will impact the final determination of the loss.

Hedging Activities

We have a hedging program that has been built primarily on hedges related to acquisitions where 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 on a discretionary basis. Taking into account all oil and natural gas production hedge contracts in place through September 30, 2008, we have hedged approximately 9 million Bbls of oil, 64 million MMBtu of natural gas, and 1 million Bbls of natural gas liquids for anticipated future production through the year 2011. No additional hedges have been entered into between September 30, 2008, and the filing date of this report. As of October 28, 2008, the approximate fair value of oil and natural gas derivative contracts designated and qualifying as cash flow hedges under SFAS No. 133 was a net asset balance of $32 million.

Recent events in the financial sector have increased the awareness of potential risks associated with hedge counterparties. As of September 30, 2008, we were in a net liability position with all of the counterparties with whom we hedge. As of October 28, 2008, we are in a net asset position with five of our counterparties and a net liability position with four of our counterparties. We have performed a financial and credit review of those specific counterparties and currently believe we will not have any material issues regarding collectability of any net receivables that may arise in the future. The majority of the counterparties with whom we hedge are also participants in our credit facility. Under this arrangement, these counterparties do not require us to post margin collateral for potential hedging liabilities since they are secured by our oil and natural gas assets and the common stock of our material subsidiaries furnished as collateral under our credit facility. We were not required to post margin with any hedge counterparties as of September 30, 2008, and through the filing date of this report. 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 for cash distributions under the Net Profits Plan are recorded as either general and administrative expense or exploration expense. These payments totaled $10.4 million and $45.9 million for the three-month and nine-month periods ended September 30, 2008. 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 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 decreased the long-term liability associated with this item to $258.3 million

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as of September 30, 2008, which resulted in a benefit of $34.9 million for the three-month period ended September 30, 2008. This decrease is related to a decrease in the estimated future net revenues used to calculate the liability, driven by overall commodity price decreases from the prior quarter. We expect approximately $55 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 sensitivity of the liability to commodity prices and reserve estimates. The Company will not be adding new Net Profits Plan pools prospectively as this compensation program has been replaced with a different long-term incentive compensation program, as described in Note 5 in 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 PSAs 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 Net Profits Plan 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 a rolling average of actual prices realized over the prior 24 months together with adjusted NYMEX strip prices for the ensuing 12 months for a total of 36 months of data. This average is supplemented by including the effect of anticipated hedge prices for the percentage of forecasted hedged production in the relevant future periods.

The calculation of the estimated liability for the Net Profits Plan is highly sensitive to our price estimates and discount rate assumption. For example, if we changed the commodity prices in our calculation by five percent, the liability recorded on the balance sheet at September 30, 2008, would differ by approximately $30 million. A one percentage point decrease in the discount rate would result in an increase to the liability of approximately $15 million, while a one percentage point increase in the discount rate would result in a decrease to the liability of approximately $14 million. We frequently re-evaluate the assumptions used in our calculation 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 made the decision 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. The fair value associated with this grant equaled $12.3 million. PSAs provide target awards that are earned over a three-year performance period. We believe this new long-term incentive plan is more transparent and will be 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 (TSR) and performance relative to our peers. 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 that measurement, 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.

Third Quarter 2008 Highlights

On July 22, 2008, 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 purchased a portion of the Company's crude oil production prior to SemGroup's petition for bankruptcy protection. As a result of the SemGroup bankruptcy filing, we recorded an allowance for doubtful accounts and bad debt expense of $9.9 million in the second quarter of 2008 and increased the allowance and the expense to $16.6 million during the third quarter of 2008. We believe that we have fully allowed for all potential uncollectible amounts and believe that we have no remaining exposure resulting from this bankruptcy. In an effort to maximize our recovery, we have filed the appropriate pleadings and are party to certain adversary proceedings in the SemGroup bankruptcy case to establish our secured and priority claims. This matter does not have a material adverse effect on our liquidity or overall financial position.

On September 8, 2008, A. Wade Pursell commenced employment as Executive Vice President and Chief Financial Officer.

Our net income for the quarter ended September 30, 2008, was $88.0 million or $1.40 per diluted share compared to 2007 results of $57.7 million or $0.89 per diluted share. We discuss these financial results and trends in more detail below.

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

	Mid-Continent	ArkLaTex	Permian	Gulf Coast	Rocky Mountain	Total(1)
Third Quarter 2008 Production:						
Oil (MBbl)	86.0	44.7	410.1	51.2	990.7	1,582.6
Gas (MMcf)	7,738.7	4,377.0	756.4	2,765.7	2,573.8	18,211.5
Equivalent (MMCFE)	8,254.8	4,645.0	3,217.0	3,072.8	8,517.8	27,707.4
Avg. Daily Equivalents (MMCFE/per day)	89.7	50.5	35.0	33.4	92.6	301.2
Relative percentage	30%	17%	12%	11%	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 September 30, 2008, and the three most recent preceding quarters. Additional details of per MCFE costs are presented later in this section.

	For the Three Months Ended			
	September 30, 2008	June 30, 2008	March 31, 2008	December 31, 2007
	(In millions, except production sales data)			
Production (BCFE)	27.7	28.6	28.3	28.5
Oil and gas production revenue, excluding the effects of hedging	$ 358.5	$ 400.0	$ 310.4	$ 273.7
Realized oil and gas hedge gain (loss)	$ (53.5)	$ (68.4)	$ (24.0)	$ (11.7)
Lease operating expense	$ 43.6	$ 41.0	$ 35.1	$ 37.8
Transportation costs	$ 6.6	$ 5.6	$ 3.9	$ 3.8
Production taxes	$ 22.5	$ 27.0	$ 20.5	$ 19.1
DD&A	$ 72.4	$ 76.4	$ 70.4	$ 64.8
Exploration	$ 10.7	$ 17.4	$ 14.3	$ 16.0
General and administrative expense	$ 24.1	$ 21.9	$ 21.1	$ 15.1
Net income	$ 88.0	$ 33.6	$ 96.0	$ 32.8
Percent change from previous quarter:				
Production (BCFE)	(3)%	1%	(1)%	4%
Oil and gas production revenues, excluding the effects of hedging	(10)%	29%	13%	20%
Realized oil and gas hedge gain (loss)	(22)%	185%	105%	(215)%
Lease operating expense	6%	17%	(7)%	2%
Transportation costs	18%	44%	3%	19%
Production taxes	(17)%	32%	7%	28%
DD&A	(5)%	9%	8%	10%
Exploration	(39)%	22%	(11)%	27%
General and administrative expense	10%	4%	39%	(4)%
Net income	162%	(65)%	192%	(43)%

First Nine Months 2008 Highlights

We have begun to more actively optimize our portfolio of assets as part of our overall strategic goals and objectives. As part of this strategy, 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. The economics of the transaction were further enhanced by utilizing a tax-advantaged exchange structure that will allow us to defer most of the gain on the sale. In June 2008 the Company completed the divestiture of certain non-strategic oil and gas properties located in the Greater Green River Basin. The cash received at closing, net of all commission costs, was $21.7 million. The final sales price is subject to normal post-closing adjustments and is expected to be finalized during the fourth quarter of 2008. We also utilized a tax-advantaged exchange structure for this divestiture. During the first nine months of 2008 we recorded a $54.1 million gain on sale of proved properties, which included the gain from the Abraxas and Greater Green River divestitures, as well as other smaller 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.

Throughout the first quarter of 2008, we repurchased a total of 2,135,600 shares of our 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 filing date of this report, 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 nine months ended September 30, 2008, was $217.6 million or $3.44 per diluted share compared to 2007 results of $156.8 million or $2.43 per diluted share. We discuss these financial results and trends in more detail below.

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

	Mid-Continent	ArkLaTex	Permian	Gulf Coast	Rocky Mountain	Total(1)
First three quarters of 2008 Production:						
Oil (MBbl)	274.7	117.1	1,251.9	194.3	3,056.5	4,894.5
Gas (MMcf)	22,526.4	12,716.7	2,417.8	10,052.7	7,524.7	55,238.2
Equivalent (MMCFE)	24,174.3	13,419.3	9,929.3	11,218.8	25,863.7	84,605.3
Avg. Daily Equivalents (MMCFE/per day)	88.2	49.0	36.2	40.9	94.4	308.8
Relative percentage	28%	16%	12%	13%	31%	100%

(1) Totals may not add due to rounding

Outlook for the Remainder of 2008

Commodity prices and drilling and well completion costs are the most significant drivers of our business. Oil and natural gas prices have declined significantly since June and early July of 2008, and forecasted natural gas and crude oil futures prices for the remainder of the year are currently lower than those used to prepare our 2008 budget. However, 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 commodity and cost environment at that time. We believe that we will continue to see volatility in the prices for oil and gas, particularly regional prices in areas where there is significant industry activity.

With respect to costs, we have seen a dramatic increase in costs to drill and complete oil and natural gas wells during the last several years. 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 in the first half of 2008 led to increased levels of capital investment in the exploration and production segment, and as a result, service providers increased

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their prices and access to equipment and services became more limited. Shortages of some items used in the drilling and completion of wells, principally drill pipe and sand, have been common in recent months. However, the recent turmoil in the financial markets and declining realized and forecasted commodity prices have led many industry participants to announce decreases to their current and forecasted drilling activity. As a result, we are beginning to see more drilling and completion equipment and services become available. Our assessment is that this trend will continue and will result in lower prices for these goods and services. However it should be noted that drilling and services availability are influenced strongly by regional factors.

As described above, management believes that we have the financial resources and liquidity to continue to execute our plan for 2008. We also believe that we have the rigs and services contracted to carry out our current program, which is described as follows:

• Mid-Continent – Our plans for the remainder of 2008 in the Mid-Continent region include operating three to four rigs in the horizontal Woodford Shale program in the Arkoma Basin, and continuing our development and exploration activities in the Anadarko Basin. In the Anadarko Basin, our technical team in the region is evaluating whether horizontal development could improve or enhance the economics of the various washes that exist in the basin. We also plan to continue exploiting a deeper formation of the Anadarko Basin where the Company has seen successful results over the past several quarters.

• ArkLaTex – Activity in the ArkLaTex for 2008 has primarily focused on programs that target the Cotton Valley and the James Lime formation. We plan to operate one horizontal rig in these programs for the remainder of the year. We are currently drilling our first horizontal Haynesville shale well at the Spider Field in DeSoto Parish, Louisiana. Additionally, we plan to monitor a number of competitor wells being drilled in East Texas targeting the Haynesville interval. A significant amount of our acreage we believe is prospective for the Haynesville shale is in East Texas. We will also perform a number of vertical tests in the Floyd shale in Northwestern Mississippi to test the potential of our acreage.

• 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 our Sweetie Peck program. We have been testing the viability of 40-acre downspacing in three pilot areas at Sweetie Peck and are encouraged by the early results of these tests. Drilling wells on 40-acre spacing has the potential to add meaningful reserves. We also plan to continue participating in Wolfberry wells at our Halff East program. Our operating team in the region continues to generate and evaluate a number of potential new exploration ideas in the region, and we will test several of these projects in 2008.

• Gulf Coast – As a result of the disruptions caused by Hurricanes Gustav and Ike, the remainder of 2008 will require some efforts to restore production that was lost or deferred due to these storms. While the impacts of the hurricanes on our operations and financial position in the Gulf Coast are not material, our operating personnel must still devote a meaningful amount of time to these efforts. For the majority of the properties impacted, in which we and our operating partners have an interest, restoration efforts will involve relatively minor repairs to facilities and infrastructure. A small number of properties will require more extensive repair work which will likely extend into 2009. Our operations group in the region will also begin planning for the remediation of our operated Vermilion 281 platform, which was lost when it was toppled in Hurricane Ike.

The Maverick Basin will be an area of significant activity for us for the remainder of 2008. Our current efforts are focused on the Pearsall and Eagleford shales, where we and several other operators have seen positive results from horizontal wells in both formations. We have been actively acquiring positions targeting both the Pearsall and Eagleford shales through grass roots leasing efforts, joint ventures, and acquisitions over the past 18 months. We continue to operate one rig that is drilling wells targeting another zone of interest, the shallow Olmos gas formation.

- Rockies – Industry attention in the Williston Basin has been focused on activity targeting the Bakken and Three Forks formations in North Dakota. We have seen progression of the play toward areas where we have acreage. St. Mary drilled three horizontal Bakken tests during the second quarter along the county line between Burke and Mountrail Counties in North Dakota. While the wells have shown modest production rates, we do not believe that the area will be commercially effective for development in the current commodity price and cost environment for the Bakken. We have one drilling rig which will begin drilling horizontal Bakken and Three Forks wells in a newly acquired acreage position during the fourth quarter of 2008. Declining oil prices combined with widening differentials and restricted pipeline takeaway capacity are potential limiting factors for development in the Williston Basin.

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 of the 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 and leasehold opportunities, both in our regional offices and at our corporate headquarters. We have a strong track record of identifying and executing economic acquisitions. In recent months, we have actively evaluated a number of projects that are very early in their development, and we continue to pursue several of these projects. This is consistent with the shift in our acquisition strategy to focus on targets that have unproved potential and drilling upside.

A three- and nine-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 September 30,		Percent Change Between Periods	For the Nine Months Ended September 30,		Percent Change Between Periods
	2008	2007		2008	2007	
Net production volumes						
Oil (MBbl)	1,583	1,796	(12)%	4,895	5,203	(6)%
Natural gas (MMcf)	18,212	16,675	9%	55,238	47,743	16%
MMCFE (6:1)	27,707	27,453	1%	84,605	78,962	7%
Average daily production						
Oil (Bbl per day)	17,203	19,526	(12)%	17,863	19,060	(6)%
Natural gas (Mcf per day)	197,952	181,249	9%	201,599	174,881	15%
MCFE per day (6:1)	301,167	298,405	1%	308,778	289,240	7%
Oil & gas production revenues (1)						
Oil production revenue	$ 131,840	$ 121,365	9%	$ 404,333	$ 313,118	29%
Gas production revenue	173,177	117,305	48%	518,731	361,399	44%
Total	$ 305,017	$ 238,670	28%	$ 923,064	$ 674,517	37%
Oil & gas production expense						
Lease operating expense	$ 43,624	$ 36,861	18%	$ 119,704	$ 102,615	17%
Transportation costs	6,638	3,169	109%	16,139	11,775	37%
Production taxes	22,462	14,940	50%	69,982	43,228	62%
Total	$ 72,724	$ 54,970	32%	$ 205,825	$ 157,618	31%
Average realized sales price (1)						
Oil (per Bbl)	$ 83.30	$ 67.56	23%	$ 82.61	$ 60.18	37%
Natural gas (per Mcf)	$ 9.51	$ 7.03	35%	$ 9.39	$ 7.57	24%
Per MCFE Data:						
Average net realized price (1)	$ 11.01	$ 8.69	27%	$ 10.91	$ 8.54	28%

Lease operating expenses		(1.57)		(1.34)	17%		(1.41)		(1.30)	8%
Transportation costs		(0.24)		(0.12)	100%		(0.19)		(0.15)	27%
Production taxes		(0.81)		(0.54)	50%		(0.83)		(0.55)	51%
General and administrative		(0.87)		(0.58)	50%		(0.79)		(0.57)	39%
Operating profit	$	7.52	$	6.11	23%	$	7.69	$	5.97	29%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$	2.61	$	2.15	21%	$	2.59	$	2.06	26%

(1) Includes the effects of hedging activities

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

	September 30, 2008	December 31, 2007	Percent Change Between Periods
Working deficit	$ (180,334)	$ (92,604)	95%
Long-term debt	$ 457,500	$ 572,500	(20)%
Stockholders' equity	$ 1,008,910	$ 863,345	17%

	For the Three Months Ended September 30,		Percent Change Between Periods	For the Nine Months Ended September 30,		Percent Change Between Periods
	2008	2007		2008	2007	
Basic net income per common share	$ 1.42	$ 0.91	56%	$ 3.50	$ 2.56	37%
Diluted net income per common share	$ 1.40	$ 0.89	57%	$ 3.44	$ 2.43	42%
Basic weighted-average shares outstanding	62,187	63,424	(2)%	62,254	61,364	1%
Diluted weighted-average shares outstanding	63,078	64,727	(3)%	63,327	64,917	(2)%

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

Changes in production volumes, oil and gas production revenues, and costs generally reflect the cyclical and highly volatile nature of our industry. 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 anticipate that oil and gas production expenses will hold flat for the remainder of 2008. Broader concerns over the general economy have resulted in lower commodity prices, which drive some of the direct costs of services used to produce oil and natural gas. Additionally, many exploration and production companies have begun to slow their activity, which should have a moderating impact on the upward cost pressure we have seen in recent quarters. 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 becomes 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. Part of executing our business during the first three quarters of 2008 consisted of adding employees. 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, unvested RSUs, and PSAs that may be 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 a reporting period since their issuance. There were no potentially dilutive shares related to the PSAs included in the diluted earnings per share calculation for the three-month and nine-month periods ended September 30, 2008. 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 September 30, 2008, and 2007, reflect an increase in outstanding shares related to stock option exercises. We issued 860,330 and 471,320 shares of common stock during the nine-month period ended September 30, 2008, and 2007, respectively, as a result of stock option exercises. Additionally, during the first nine months of 2008 and 2007, we issued 413,500 and 302,370 shares of common stock, respectively, as a result of the settlement of RSUs by the issuance of common stock in accordance with the terms of the RSU grants.

Overview of Liquidity and Capital Resources

As noted previously in this section, 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 be near our planned capital investment budget for exploration and development. Accordingly, we do not expect to access the capital markets for the remainder of 2008. Net cash proceeds from the sale of oil and gas properties totaled $155.2 million for the nine-month period ended September 30, 2008, which includes proceeds related to the Abraxas and Greater Green River Basin divestitures completed in January and June of 2008, respectively. We anticipate that we will continue to evaluate our property base for divestiture candidates that are not considered 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. Capital markets have been experiencing extreme volatility and disruptions, and in recent weeks the volatility and disruptions have reached unprecedented levels. Those circumstances, along with the recent decline in oil and natural gas prices, have constrained the availability of public debt and equity financing for exploration and production companies. However, we do not anticipate any need to raise either public debt or equity financing in the foreseeable future to fund our ongoing operations. 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. Given our cash flows from operating activities and our available borrowing capacity under the credit facility, we believe we have sufficient liquidity to fund ongoing operational obligations and budgeted capital expenditures for the remainder of 2008 and 2009.

Current credit facility

We have a revolving credit facility agreement with Wachovia Bank, Wells Fargo Bank, and nine other participating banks. No individual lender represents more than 11 percent of the lending commitments under the credit facility. On October 1, 2008, the lending group redetermined our reserve-based borrowing base under the credit facility at the previous amount 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. This credit facility agreement has a maturity date of April 7, 2010. As of October 28, 2008, we had $302 million of available borrowing capacity under this facility. Interest and commitment fees are accrued based on the borrowing base utilization table located in Note 7 – Long-term Debt in Part I, Item 1 of this report. 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.

Our weighted-average interest rate paid in the three-month and nine-month periods ended September 30, 2008, was 4.4 percent and 4.7 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.

We are subject to customary financial and non-financial covenants under our credit facility, including limitations on dividend payments and requirements to maintain certain financial ratios, which include debt to earnings before interest, taxes, depreciation, and amortization ("EBITDA") of less than 3.5 to 1.0 and a current ratio as defined by our credit agreement of not less than 1.0 to 1.0. As of September 30, 2008, our debt to EBITDA ratio and current ratio as defined by our credit agreement, were 0.56 and 1.77, respectively. We are in compliance with all financial and non-financial covenants under this credit facility and expect to be in compliance for the foreseeable future.

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 nine months of 2008 we spent $494.5 million for exploration and development capital expenditures, $83.4 million for property acquisitions, and $77.2 million for share repurchases. 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 $758 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. 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 filing date of this report 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. As of September 30, 2008, we have accrued for $3.1 million in dividends to be paid to stockholders of record as of the close of business October 31, 2008. Our intention is to continue to make these semi-annual dividend payments at the rate of $0.05 per share 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 amount and percentage changes in cash flows between the nine-month periods ended September 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 Nine Months Ended September 30,			Percent
	2008	2007	Change	Change
	(In thousands)			
Net cash provided by operating activities	$ 568,101	$ 473,982	$ 94,119	20%
Net cash used in investing activities	$ (432,545)	$ (540,357)	$ 107,812	(20)%
Net cash provided by (used in) financing activities	$ (173,670)	$ 82,151	$ (255,821)	(311)%

Analysis of cash flow changes between the nine months ended September 30, 2008 and September 30, 2007

Operating activities. Cash received from oil and gas production revenue, net of the realized effects of hedging, increased $266.9 million to $937.6 million for the nine-month period ended September 30, 2008, compared with $670.7 million for the nine-month period ended September 30, 2007. Included in operating revenues for the nine-month period ended September 30, 2008, is $145.8 million of net realized hedging losses. A 37 percent increase in oil and gas production revenue, net of the realized effects of hedging, was the result of a seven 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 nine months of 2008 increased $20.0 million relative to the same period in 2007.

Investing activities. Total cash outflow during the nine months ended September 30, 2008, for capital expenditures, leasehold, and drilling activities decreased $5.6 million or one percent to $494.5 million. Cash proceeds from the sale of oil and gas properties totaled $155.2 million for the nine-month period ended September 30, 2008, which includes proceeds related to the Abraxas and Greater Green River Basin divestitures completed in January and June of 2008, respectively. Total cash outflow for the nine months ended September 30, 2008, relating to the acquisition of oil and gas properties increased $50.8 million to $83.4 million due to the acquisition of assets at Carthage Field. At September 30, 2007, we had paid a $15.3 million deposit related to the Rockford acquisition that closed in October of 2007. We received $7.1 million less in proceeds from insurance settlement for the nine-month period ended September 30, 2008, compared with the same period in 2007. Other cash flows from investing activities for the nine-month period ended September 30, 2008, include the refunding of a $10.0 million deposit related to the Abraxas divestiture.

Financing activities. Net repayments on our credit facility decreased by $64.0 million for the nine-month period ended September 30, 2008, compared with the same period in 2007. Cash flows from financing activities for the nine months ended September 30, 2007, included a $4.5 million repayment on a short-term note payable. We spent $51.3 million more to repurchase shares of our common stock during the nine-month period ended September 30, 2008, compared with the same period in 2007. We received $280.7 million less in the nine-month period ended September 30, 2008, compared to the same period in 2007 due to the issuance of our 3.50% Senior Convertible Notes in the second quarter of 2007. Our excess tax benefit attributed to the exercise of stock options increased by $2.6 million for the nine-month period ended September 30, 2008, compared with the same period in 2007. We received $5.0 million more from the sale of common stock for the nine-month period ended September 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 $758 million. This amount excludes non-cash asset retirement obligation capitalized assets. In the third quarter of 2008 we increased our capital investment budget from $661 million to $758 million in order to expand our level of activity in the Woodford shale, the Wolfberry tight oil program at Halff East, and the horizontal Bakken program, as well as to drill our first two horizontal Haynesville shale wells. 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)
Mid-Continent region	$ 167
ArkLaTex region	190
Permian region	150
Gulf Coast region	86
Rocky Mountain region	165
	$ 758

We regularly review our capital investment budget to reflect the 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 near our anticipated operating cash flows for 2008. Of our 2008 capital expenditures budget of $758 million, we have spent $529.4 million through September 30, 2008.

The following table sets forth certain historical information regarding the costs incurred by us in our oil and gas activities.

	For the Nine Months Ended September 30	
	2008	2007
	(In thousands)	
Development costs (1)	$ 456,135	$ 411,076
Exploration costs	73,232	98,650
Acquisitions		
Proved properties	41,393	32,876
Unproved properties – acquisitions of proved properties (2)	42,389	(225)
Unproved properties - other	20,154	35,686
Total, including asset retirement obligation (3)	$ 633,303	$ 578,063

(1) Includes capitalized interest of $2.8 million in 2008 and $3.8 million in 2007.
(2) Represents a portion of the allocated purchase price of unproved properties acquired as part of the acquisition of proved properties. Refer to Note 3 in Part I, Item I of this report for additional information.
(3) Includes amounts relating to estimated asset retirement obligations of $8.8 million in 2008 and $7.4 million in 2007.

Costs incurred for capital and exploration activities during the first nine months of 2008 increased $55.2 million or 10 percent compared to the same period in 2007. Excluding acquisitions, our development and exploration investments increased $19.6 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 nine months of 2008 compared with the same period in 2007. The $35.6 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.

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 natural 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.

Commodity price risk and interest rate risk

We are exposed to market risk, including the effects of changes in oil and natural gas prices and changes in interest rates, as discussed above. Since we produce and sell crude oil, natural gas, and natural gas liquids, our financial results are affected when prices for these commodities fluctuate as they are doing presently. In order to reduce the impact of the 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 the 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. As of September 30, 2008, all oil, natural gas, and natural gas liquid derivative instruments qualified as cash flow hedges for accounting purposes.

Our net realized oil and natural 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 of our forecasted production on a discretionary basis. As of September 30, 2008, our hedged positions totaled approximately 9 million Bbls of crude oil, 64 million MMBtu of natural gas, and 1 million Bbls of natural gas liquids of anticipated future production through 2011. We have not entered into any new hedges from September 30, 2008, through the filing date of this report.

In a typical commodity swap agreement, if the agreed-upon published third-party price is lower than the swap fixed price, we receive the difference between the index price per unit of production and 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.

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Our oil and natural gas derivative contracts are accounted for using fair value as defined under SFAS No. 157. Level 2 inputs, as defined by SFAS No. 157, are used to measure fair value and include internal valuation estimates that consider forward price quotes from active markets, third party pricing services, counterparties' credit ratings, our credit rating, and the time value of money. The considered factors result in an estimated exit-price for each asset or liability under a market place participant's view.

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. Deterioration in a counterparty's credit will result in a lower valuation of our derivative assets. We monitor the counterparties' credit ratings using two different ratings agencies and may ask counterparties to post collateral if their ratings deteriorate. In some instances we will attempt to novate the trade to obtain a more stable counterparty. While the ratings of our counterparties have decreased over the past several months, the decreases have been slight. In the event that we determine the likelihood that a counterparty will not default ceases to be probable, the hedge relationship will no longer qualify for hedge accounting prospectively. If hedge accounting is discontinued and the derivative remains outstanding, we will recognize all subsequent changes in fair value on our consolidated statement of operations for the period in which the change occurs. Valuation adjustments are necessary to reflect the effect of our credit quality on the fair value of any liability position with a counterparty. This adjustment takes into account any credit enhancements, such as collateral margin that we may have posted with a counterparty, as well as any letters of credit between the parties. The methodology to determine this adjustment is consistent with how we evaluate counterparty credit risk, taking into account our credit rating, current credit spreads, and any change in such spreads since the last measurement date. The majority of our derivative counterparties are members of our lending group. Deterioration in our credit will result in a lower valuation of our derivative liability. As of September 30, 2008, we were in a net liability position with all of our counterparties.

The methods described above may result in a fair value estimate that may not be indicative of net realizable value or may not be reflective of future fair values and cash flows. While we believe that the valuation methods utilized are appropriate and consistent with the requirements of SFAS No. 157 and with other marketplace participants, we recognize 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.

The following tables describe the volumes, average contract prices, and fair value of contracts we have in place as of September 30, 2008.

Oil Contracts

Oil Swaps

Contract Period	Volumes (Bbl)	Weighted-Average Contract Price (Per Bbl)	Fair Value at September 30, 2008 (Liability) (In thousands)
Fourth quarter 2008			
NYMEX WTI	451,000	$ 71.83	$ (12,798)
WCS	15,000	$ 50.42	(431)
2009			
NYMEX WTI	1,570,000	$ 71.64	(46,534)
2010			
NYMEX WTI	1,239,000	$ 66.47	(43,560)
2011			
NYMEX WTI	1,032,000	$ 65.36	(35,981)
All oil swap contracts	4,307,000		$ (139,304)

Oil Collars

Contract Period	NYMEX WTI Volumes (Bbl)	Weighted-Average Floor Price (Per Bbl)	Weighted-Average Ceiling Price (Per Bbl)	Fair Value at September 30, 2008 (Liability) (In thousands)
Fourth quarter 2008	519,000	$ 58.19	$ 78.43	$ (12,764)
2009	1,526,000	$ 50.00	$ 67.31	(54,509)
2010	1,367,500	$ 50.00	$ 64.91	(52,934)
2011	1,236,000	$ 50.00	$ 63.70	(47,182)
All oil collars	4,648,500			$ (167,389)

Gas Contracts

Gas Swaps			
Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at September 30, 2008 Asset/(Liability)
	(MMBtu)	(per MMBtu)	(In thousands)
Fourth quarter 2008 -			
IF CIG	930,000	$ 7.45	$ 2,876
IF PEPL	1,490,000	$ 8.32	5,220
IF NGPL	160,000	$ 7.10	368
IF ANR OK	610,000	$ 8.22	1,951
IF EL PASO	300,000	$ 7.20	561
IF HSC	2,100,000	$ 8.77	3,449
NYMEX Henry Hub	270,000	$ 9.72	578
2009 -			
IF CIG	2,310,000	$ 7.72	4,714
IF PEPL	3,360,000	$ 8.06	3,984
IF NGPL	440,000	$ 7.11	5
IF ANR OK	1,340,000	$ 8.09	1,657
IF EL PASO	1,200,000	$ 7.11	(58)
IF HSC	10,490,000	$ 8.57	7,995
NYMEX Henry Hub	1,280,000	$ 9.03	1,080
2010 -			
IF NGPL-	60,000	$ 7.60	(51)
IF ANR OK	60,000	$ 7.98	(34)
IF EL PASO	1,090,000	$ 6.79	(881)
IF HSC	6,080,000	$ 8.40	919
NYMEX Henry Hub	1,440,000	$ 8.66	119
2011 -			
IF EL PASO	880,000	$ 6.34	(1,113)
IF HSC	360,000	$ 9.01	91
All gas swap contracts	36,250,000		$ 33,430

Gas collars				
Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at September 30, 2008 Asset/(Liability)
	(MMBtu)	(per MMBtu)	(per MMBtu)	(In thousands)
Fourth quarter 2008 -				
IF CIG	720,000	$ 5.60	$ 8.72	$ 1,007
IF PEPL	1,657,500	$ 6.28	$ 9.42	2,659
IF HSC	240,000	$ 6.57	$ 9.70	34
IF RELIANT	1,220,000	$ 8.75	$ 10.20	4,879
NYMEX Henry Hub	120,000	$ 7.00	$ 10.57	14
2009 -				
IF CIG	2,400,000	$ 4.75	$ 8.82	581
IF PEPL	5,510,000	$ 5.30	$ 9.25	(963)
IF HSC	840,000	$ 5.57	$ 9.49	(295)
NYMEX Henry Hub	360,000	$ 6.00	$ 10.35	(94)
2010 -				
IF CIG	2,040,000	$ 4.85	$ 7.08	215
IF PEPL	4,945,000	$ 5.31	$ 7.61	(4,933)
IF HSC	600,000	$ 5.57	$ 7.88	(651)
NYMEX Henry Hub	240,000	$ 6.00	$ 8.38	(247)
2011				
IF CIG	1,800,000	$ 5.00	$ 6.32	(866)
IF PEPL	4,225,000	$ 5.31	$ 6.51	(6,000)
IF HSC	480,000	$ 5.57	$ 6.77	(763)
NYMEX Henry Hub	120,000	$ 6.00	$ 7.25	(178)
All gas collars	27,517,500			$ (5,601)

Natural Gas Liquid Contracts

Natural Gas Liquid Swaps*			
Contract Period	Volumes (Bbls)	Weighted-Average Contract Price (per Bbl)	Fair Value at September 30, 2008 Asset/(Liability) (In thousands)
Fourth quarter 2008	245,992	$ 40.79	$ (2,768)
2009	813,732	$ 41.87	(7,136)
2010	139,723	$ 49.59	602
2011	19,643	$ 49.01	71
All natural gas liquid swaps	1,219,090		$ (9,231)

*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 that 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 September 30, 2008, and 2007	Change Between the Nine Months Ended September 30, 2008 and 2007
Oil and gas production revenues		
Increase in oil and gas production revenues,net of hedging (In thousands)	$ 66,347	$ 248,547

Components of revenue increases (decreases):

Oil		
Realized price change per Bbl, including the effects of hedging	$ 15.74	$ 22.43
Realized price percentage change	23%	37%
Production change (MBbl)	(213)	(308)
Production percentage change	(12)%	(6)%
Natural Gas		
Realized price change per Mcf, including the effects of hedging	$ 2.48	$ 1.82
Realized price percentage change	35%	24%
Production change (MMcf)	1,537	7,495
Production percentage change	9%	16%

Production mix as a percentage of total oil and gas revenue, including the effects of hedging, and production:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
Revenue	2008	2007	2008	2007
Oil	43%	51%	44%	46%
Natural gas	57%	49%	56%	54%
Production				
Oil	34%	39%	35%	40%
Natural gas	66%	61%	65%	60%

Information regarding the components of exploration expense

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Summary of Exploration Expense	(In millions)			
Geological and geophysical expenses	$ 2.0	$ 4.4	$ 5.1	$ 9.4
Exploratory dry hole expense	-	1.5	6.6	12.7
Overhead and other expenses	8.7	6.7	30.7	20.6

Total	$	10.7	$	12.6	$	42.4	$	42.7

Information regarding the effects of oil and gas hedging activity:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Oil Hedging				
Percentage of oil production hedged	66%	64%	62%	65%
Oil volumes hedged (MBbl)	1,040	1,154	3,037	3,371
Decrease in oil revenue	$ (45.4 million)	$ (7.4 million)	$ (124.5 million)	$ (9.3 million)
Average realized oil price per Bbl before hedging	$ 111.97	$ 71.68	$ 108.04	$ 61.97
Average realized oil price per Bbl after hedging	$ 83.30	$ 67.56	$ 82.61	$ 60.18
Natural Gas Hedging				
Percentage of gas production hedged	50%	47%	44%	47%
Natural gas volumes hedged (MMBtu)	9.7 million	8.2 million	25.8 million	23.6 million
Increase (decrease) in gas revenue	$ (8.1 million)	$ 17.6 million	$ (21.4 million)	$ 45.5 million
Average realized gas price per Mcf before hedging	$ 9.96	$ 5.98	$ 9.78	$ 6.63
Average realized gas price per Mcf after hedging	$ 9.51	$ 7.03	$ 9.39	$ 7.57

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

Oil and gas production revenue. Production increased 1 percent to 27.7 BCFE for the quarter ended September 30, 2008, compared with 27.5 BCFE for the quarter ended September 30, 2007. The production for the quarter ended September 30, 2007, includes approximately 1.3 BCFE related to non-core properties divested 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 Increase (Decrease)	Pre-Hedge Oil and Gas Revenues Increase	Production Costs Increase
	(MMCFE)	(In millions)	(In millions)
Mid-Continent	(539.3)	$ 31.7	$ 1.4
ArkLaTex	1,162.8	28.4	2.3
Permian	408.3	28.4	3.9
Gulf Coast	654.2	23.1	4.8
Rocky Mountain	(1,431.9)	29.8	5.4
Total	254.1	$ 141.4	$ 17.8

Year over year, we were able to grow production in the ArkLaTex, Gulf Coast and Permian regions during the third quarter of 2008. The increase in production in the ArkLaTex region is the result of the successful Elm Grove, Terryville, Carthage, and James Lime programs where we have been increasing our capital investment. 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

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several offshore wells. The Olmos properties were acquired in the fourth quarter of 2007. The production increase in the Permian is due to continued successful drilling in our Wolfberry tight oil program. The declines in the Mid-Continent and Rocky Mountain regions are due primarily to the divestiture of non-core properties in 2008.

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

	For the Three Months Ended September 30,	
	2008	2007
Realized oil price ($/Bbl)	$ 111.97	$ 71.68
Realized gas price ($/Mcf)	$ 9.96	$ 5.98
Realized equivalent price ($/MCFE)	$ 12.94	$ 8.32

The combination of higher production volumes 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 $53.5 million for the three-month period ended September 30, 2008, mainly related to settlements on oil hedges, compared with a $10.2 million gain for the same period in 2007, which was mainly due to favorable settlements on natural gas hedges.

Marketed gas system revenue and expense. Marketed gas system revenue increased $16.8 million to $24.2 million for the quarter ended September 30, 2008, compared with $7.4 million for the comparable period of 2007. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased $15.7 million to $23.0 million for the quarter ended September 30, 2008, compared with $7.3 million for the comparable period of 2007. The net margin has stayed consistent with historical performance. We expect that marketed gas system revenue and expense will continue to coincide with increases and decreases in production and our net realized price.

Oil and gas production expense. Total production costs increased $17.8 million, or 32 percent, to $72.7 million for the third quarter of 2008 from $55.0 million in the comparable period of 2007. Total oil and gas production costs per MCFE increased $0.62 to $2.62 for the third quarter of 2008, compared with $2.00 for the same period in 2007. This increase is comprised of the following:

- A $0.12 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 fourth quarter of 2007, as well as recently completed wells which have higher transportation costs

- A $0.27 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

- An $0.18 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 $0.05 overall increase in workover LOE on a per MCFE basis relating to several large workover charges in the Mid-Continent region.

Depletion, depreciation, amortization and asset retirement obligation liability accretion. DD&A increased $13.3 million or 23 percent to $72.4 million for the three-month period ended September 30, 2008, compared with $59.1 million for the same period in 2007. DD&A expense per MCFE increased 21 percent to $2.61 for the three-month period ended September 30, 2008, compared to $2.15 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 higher per unit rates. Additionally, this increase reflects the costs of production facilities in the offshore Gulf Coast that have increased significantly in recent years and that are now impacting our DD&A rate as those projects begin production.

Exploration. Exploration expense decreased $1.9 million or 15 percent to $10.7 million for the three-month period ended September 30, 2008, compared with $12.6 million for the same period in 2007. The decrease is attributable to no exploratory dry holes being drilled in the third quarter of 2008.

General and administrative. General and administrative expense increased $8.3 million or 53 percent to $24.1 million for the quarter ended September 30, 2008, compared with $15.8 million for the comparable period of 2007. G&A expense increased $0.29 to $0.87 per MCFE for the third quarter of 2008 compared to $0.58 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 $5.2 million between the third quarter of 2008 and the third quarter of 2007. A significant driver of this headcount increase has been the conversion from contract lease operators to internal lease operators. 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 third quarter of 2008, 17 of our 21 pools are in payout status. No additional pools are expected to reach payout in 2008.

Cash bonus and long-term incentive compensation expense is $2.8 million higher than in the prior year, primarily caused by the increase in employee count and improved company performance in the current year. The above amounts combined with a net $1.8 million increase in other G&A expense items, which includes charitable contributions and office supplies, were offset by a $3.0 million increase in the amount of general and administrative expense that was allocated to exploration expense, as well as a $1.9 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 September 30, 2008, we recorded $6.7 million of bad debt expense as a result of SemGroup, affiliates of which purchase a portion of our crude oil production, filing for bankruptcy protection. This amount related to July 2008 oil production that was reserved for in the three-month period ended September 30, 2008.

Change in Net Profits Plan liability. For the quarter ended September 30, 2008, this non-cash item was a benefit of $34.9 million compared to an expense of $3.1 million for the same period in 2007. Significant decreases in oil and gas commodity prices during the third quarter of 2008 have decreased the estimated liability for the 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.

Other expense. Other expense increased $7.3 million to $7.8 million for the quarter ended September 30, 2008, compared with $460,000 for the same period in 2007. We recognized a $7.0 million loss related to hurricanes for the estimated remediation associated with the Vermilion 281 platform and various other property damage repair costs we expect to incur in excess of our maximum insurance policy limit. Additionally, we wrote off the carrying value associated with the Vermilion 281 platform and the production facilities located at Goat Island.

Income tax expense. Income tax expense totaled $51.2 million for the third quarter of 2008 compared with $34.0 million for the third quarter of 2007 resulting in effective tax rates of 36.8 percent and 37.1 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 decreased for the third quarter of 2008 compared to the same period of 2007 due to the impact on estimated taxable income from additional intangible drilling cost deductions related to increased capital spending, incentive compensation program related expenses, and declining commodity prices. This trend is expected to continue throughout the remainder of 2008 based upon our current projected capital expenditures program and commodity price outlook.

Comparison of Financial Results and Trends between the nine months ended September 30, 2008, and 2007

Oil and gas production revenue. Production increased 7 percent to 84.6 BCFE for the nine months ended September 30, 2008, compared with 79.0 BCFE for the nine months ended September 30, 2007. The production for the nine-month periods ended September 30, 2008, and 2007, includes approximately 0.4 BCFE and 3.7 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 Increase (Decrease)	Pre-Hedge Oil and Gas Revenues Increase	Production Costs Increase
	(MMCFE)	(In millions)	(In millions)
Mid-Continent	(1,026.1)	$ 55.1	$ 4.6
ArkLaTex	3,595.5	72.7	6.0
Permian	2,230.2	95.3	11.3
Gulf Coast	4,426.6	83.3	16.6
Rocky Mountain	(3,583.3)	124.1	9.7
Total	5,642.9	$ 430.5	$ 48.2

We grew production by approximately 5,600 MMCFE in the first three quarters 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 are the result of the divestiture of non-core properties in these regions, which resulted in a smaller production base for 2008.

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

	For the Nine Months Ended September 30,	
	2008	2007
Realized oil price ($/Bbl)	$ 108.04	$ 61.97
Realized gas price ($/Mcf)	$ 9.78	$ 6.63
Realized equivalent price ($/MCFE)	$ 12.63	$ 8.08

The combination of higher production volumes 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 $145.8 million for the nine-month period ended September 30, 2008, mainly related to settlements on oil hedges. In the first three quarters of 2007 we realized a $36.2 million hedge gain mainly due to favorable settlements on natural gas hedges.

Marketed gas system revenue and expense. Marketed gas system revenue increased $34.2 million to $65.4 million for the nine-month period ended September 30, 2008, compared with $31.2 million for the comparable period of 2007. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased $31.5 million to $60.9 million for the nine-month period ended September 30, 2008, compared with $29.5 million for the comparable period of 2007. The net margin has stayed consistent with historical performance.

Other revenue. Other revenue decreased $8.5 million to $590,000 for the nine-month period ended September 30, 2008, compared with $9.1 million for the comparable period of 2007. We recognized a gain of $6.3 million for the nine-month period ended September 30, 2007, which is included in the line item other revenue on the consolidated statement of operations. This gain was related to the global insurance settlement for reimbursement of damages sustained during Hurricane Rita.

Gain on sale of proved properties. We recorded a gain on sale of proved properties of $54.1 million during the first three quarters of 2008 mainly related to the Abraxas divestiture in January of 2008. The final gain on sale of proved properties will be adjusted for normal post-closing adjustments and is expected to be finalized during the fourth quarter of 2008. There were no sales of proved properties during the first three quarters of 2007. We expect to continue to evaluate potential divestitures of non-strategic properties.

Oil and gas production expense. Total production costs increased $48.2 million, or 31 percent, to $205.8 million for the nine-month period ended September 30, 2008, from $157.6 million in the comparable period of 2007. Total oil and gas production costs per MCFE increased $0.43 to $2.43 for the first nine months of 2008, compared with $2.00 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 fourth quarter of 2007

- A $0.28 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 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

- A $0.02 overall increase in workover LOE on a per MCFE basis relating to significant workover charges in the Mid-Continent region

Depletion, depreciation, amortization and asset retirement obligation liability accretion. DD&A increased $56.4 million or 35 percent to $219.1 million for the nine-month period ended September 30, 2008, compared with $162.7 million for the same period in 2007. DD&A expense per MCFE increased 26 percent to $2.59 for the nine-month period ended September 30, 2008, compared to $2.06 for the same period in 2007. This increase is due to a higher per unit rate associated with our acquisition and drilling costs in 2007 and 2006 in addition to overall upward cost pressure in the industry in recent years. Additionally, this increase reflects the costs of production facilities in the offshore Gulf Coast that have increased significantly in recent years and that are now impacting our DD&A rate as those projects begin production.

Exploration. Exploration expense decreased $277,000 or 1 percent to $42.4 million for the nine-month period ended September 30, 2008, compared with $42.7 million for the same period in 2007. For the nine-month periods ended September 30, 2008, and 2007, we recorded $6.6 million in exploratory dry hole expense related to two wells located in the ArkLaTex region, and $12.7 million in exploratory dry hole expense related to wells located in the Gulf Coast region and one well in the Rocky Mountain region, respectively. However, the decrease in exploratory dry hole expense was offset by an increase in overhead and other expenses related to an increase in the size of our geological and exploration staff throughout 2008.

Impairment of proved properties. Impairment of proved properties increased $10.1 million for the nine-month period ended September 30, 2008, compared with no impairment of proved properties expense for the same period in 2007. This increase reflects the impairment in the second quarter of 2008 related to wells located at the Apple Springs field in the ArkLaTex.

General and administrative. General and administrative expense increased $22.2 million or 49 percent to $67.1 million for the nine months ended September 30, 2008, compared with $45.0 million for the comparable period of 2007. G&A expense increased $0.22 to $0.79 per MCFE for the first nine months of 2008 compared to $0.57 per MCFE for the same period in 2007.

A 33 percent increase in employee count has resulted in an increase in base employee compensation, including payroll taxes and benefits, of approximately $13.7 million between the first nine months of 2008 and the same period in 2007. An $11.5 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 bonus and long-term incentive compensation expense is $6.3 million higher than in the prior year, which is primarily caused by the increase in employee count and improved company performance in the current year. The above amounts combined with a net $4.3 million increase in other G&A expense items, which includes charitable contributions and office supplies, were offset by a $7.5 million increase in the amount of general and administrative expense that was allocated to exploration expense, as well as a $6.1 million increase in COPAS overhead reimbursements. A portion of the increase in the amount of general and administrative expense is due to G&A expense related to the Net Profits Plan expense attributable to former employees 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 $16.6 million of bad debt expense as a result of SemGroup, affiliates of which purchase a portion of our crude oil production, filing for bankruptcy protection. This amount related to oil produced in June and July of 2008 that was reserved in the nine-month period ended September 30, 2008.

Change in Net Profits Plan liability. For the nine-month period ended September 30, 2008, this non-cash expense was $46.9 million compared to $6.9 million for the same period in 2007. Increases in oil and gas commodity prices between the two periods triggered additional Net Profits Plan payouts and increased the periodic expense for the estimate of the amounts forecasted to be paid to plan participants.

Other expense. Other expense increased $7.6 million to $9.2 million for the nine-month period ended September 30, 2008, compared with $1.6 million for the same period in 2007. The increase is due to us recording a $7.0 million loss related to hurricanes.

Income tax expense. Income tax expense totaled $126.9 million for the nine-month period of 2008 compared with $92.7 million for the same period of 2007 resulting in effective tax rates of 36.8 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 absolute terms and on a percentage basis for the nine months ended September 30, 2008, compared to the nine months ended September 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

Please see Note 11 – Fair Value Measurements and Note 16 – 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 expenditure or materially adverse effects on our liquidity or results of operations. We believe we are in substantial compliance with environmental regulations and do not currently anticipate that material expenditures will be required in the future. However, we are unable to predict the impact that future compliance with regulations may have on future capital expenditures, liquidity, and results of operations.

Cautionary Information about Forward-Looking Statements

This Quarterly Report on Form 10-Q contains "forward-looking statements' within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this Form 10-Q that address activities, events, or developments that we expect, believe, or anticipate will or may occur in the future are forward-looking statements. The words "anticipate," "assume," "believe," "budget," "estimate," "expect," "forecast," "intend," "plan," "project," "will," and similar expressions are intended to identify forward-looking statements. Forward-looking statements appear in a number of places in this Form 10-Q and include statements about such matters as:

- The amount and nature of future capital expenditures and the availability of liquidity and 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 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 analysis made by us in light of our experience and our perception of historical trends, current condition, 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, including constraints on availability of opportunities and financing due to currently distressed capital and credit market conditions

- The risks of hedging strategies

- Lower prices realized on oil and gas sales resulting from our commodity price risk management activities

- The uncertain nature of the expected benefits from the acquisitions and divestitures of oil and gas properties, including uncertainties in evaluating oil and natural gas reserves of acquired properties and associated potential liabilities

- The imprecise nature of oil and gas reserve estimates

- Uncertainties inherent in projecting future rates of production from drilling activities and acquisitions

- 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 and credit facility participants

- The negative impact that lower oil and natural gas prices could have on our ability to borrow and fund budgeted capital expenditures

- 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 is 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 Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

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

Except as set forth below and as disclosed in our quarterly report on Form 10-Q for the quarter ended June 30, 2008, 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.

Oil and natural gas prices reached significant highs during June and early July of 2008 and have declined significantly since that time. The significant decline in oil and natural gas prices has reduced our operating cash flows and may ultimately affect our access to the capital markets. In addition, the capital and credit markets have been experiencing extreme volatility and disruptions for the last several months, and in recent weeks the volatility and disruptions have reached unprecedented levels. Recent concerns about credit market conditions and the crisis affecting the banking system which resulted in the enactment in October 2008 of the Emergency Economic Stabilization Act of 2008 have led to an economic slowdown, which may further affect the demand for oil and natural gas. Although we currently believe that our liquidity and available capital resources through operating cash flows and our existing credit facility with eleven participating banks are sufficient to fund our ongoing operational obligations and budgeted capital expenditures for the foreseeable future, continued distressed capital and credit market conditions and decreased oil and natural gas prices could ultimately limit our access to capital and have a material adverse effect on our liquidity, financial condition, results of operations and cash flows.

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We are currently engaged in marketing for sale certain non-core oil and natural gas properties located in the Rocky Mountain, Gulf Coast and Mid-Continent regions, and our balance sheet as of September 30, 2008, includes a total of $25.7 million of assets held for sale, net of accumulated depletion, depreciation and amortization. As a result of the distressed conditions in the capital and credit markets and significant declines in oil and natural gas prices over the last several months, we may not be able to complete our planned divestitures of non-core properties on terms that we find economically attractive.

ITEM 6. EXHIBITS

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

Exhibit	Description
10.1†	St. Mary Land & Exploration Company Form of Performance Share Award Agreement (filed as Exhibit 10.4 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).
10.2†	St. Mary Land & Exploration Company Form of Performance Share Award Notice (filed as Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
32.1**	Certification pursuant to U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes – Oxley Act of 2002
99.1*	Audit Committee Pre-Approval of Non-Audit Services

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

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

November 4, 2008	By: /s/ ANTHONY J. BEST Anthony J. Best President and Chief Executive Officer
November 4, 2008	By: /s/ A. WADE PURSELL A. Wade Pursell Executive Vice President and Chief Financial Officer
November 4, 2008	By: /s/ MARK T. SOLOMON Mark T. Solomon Controller