ST MARY LAND & EXPLORATION CO
Form 10-Q
November 03, 2009

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, 2009

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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes o 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 27, 2009 the registrant had 62,536,644 shares of common stock, $0.01 par value, outstanding.

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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)

	September 30, 2009	December 31, 2008 (As adjusted, Note 7)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 20,517	$ 6,131
Short-term investments	-	1,002
Accounts receivable, net of allowance for doubtful accounts of $16,919 in 2009 and $16,788 in 2008	98,709	157,690
Refundable income taxes	2,821	13,161
Prepaid expenses and other	16,802	22,161
Accrued derivative asset	41,428	111,649
Total current assets	180,277	311,794
Property and equipment (successful efforts method), at cost:		
Land	1,371	1,350
Proved oil and gas properties	2,804,559	2,969,722
Less - accumulated depletion, depreciation, and amortization	(1,063,232)	(947,207)
Unproved oil and gas properties, net of impairment allowance of $51,511 in 2009 and $42,945 in 2008	147,825	168,817
Wells in progress	56,958	90,910
Materials inventory, at lower of cost or market	30,411	40,455
Oil and gas properties held for sale less accumulated depletion, depreciation, and amortization	148,937	1,827
Other property and equipment, net of accumulated depreciation of $16,617 in 2009 and $13,848 in 2008	14,516	13,458
	2,141,345	2,339,332
Other noncurrent assets:		
Accrued derivative asset	4,614	21,541
Restricted cash subject to Section 1031 Exchange	-	14,398
Other noncurrent assets	17,523	10,182
Total other noncurrent assets	22,137	46,121

Total Assets	$	2,343,759		$	2,697,247	
LIABILITIES AND STOCKHOLDERS' EQUITY						
Current liabilities:						
Accounts payable and accrued expenses	$	215,363		$	254,811	
Accrued derivative liability		25,370			501	
Deferred income taxes		8,424			41,289	
Total current liabilities		249,157			296,601	
Noncurrent liabilities:						
Long-term credit facility		235,000			300,000	
Senior convertible notes, net of unamortized discount of $22,716 in 2009, and $28,787 in 2008		264,784			258,713	
Asset retirement obligation		68,682			108,755	
Asset retirement obligation associated with oil and gas properties held for sale		23,711			238	
Net Profits Plan liability		163,328			177,366	
Deferred income taxes		285,042			354,328	
Accrued derivative liability		46,315			27,419	
Other noncurrent liabilities		11,623			11,318	
Total noncurrent liabilities		1,098,485			1,238,137	
Commitments and contingencies						
Stockholders' equity:						
Common stock, $0.01 par value: authorized - 200,000,000 shares; issued: 62,638,839 shares in 2009 and 62,465,572 shares in 2008; outstanding, net of treasury shares: 62,511,946 shares in 2009 and 62,288,585 shares in 2008		626			625	
Additional paid-in capital		151,620			141,283	
Treasury stock, at cost: 126,893 shares in 2009 and 176,987 shares in 2008		(1,230	)		(1,892	)
Retained earnings		850,593			957,200	
Accumulated other comprehensive income (loss)		(5,492	)		65,293	
Total stockholders' equity		996,117			1,162,509	
Total Liabilities and Stockholders' Equity	$	2,343,759		$	2,697,247	

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,	
	2009	2008	2009	2008
		(As adjusted, Note 7)		(As adjusted, Note 7)
Operating revenues and other income:				
Oil and gas production revenue	$ 152,651	$ 358,508	$ 428,347	$ 1,068,901
Realized oil and gas hedge gain (loss)	28,331	(53,491)	127,230	(145,837)
Gain (loss) on divestiture activity (Note 13)	(11,277)	(4,992)	(10,632)	54,063
Marketed gas system and other operating revenue	16,082	24,063	45,260	66,005
Total operating revenues and other income	185,787	324,088	590,205	1,043,132
Operating expenses:				
Oil and gas production expense	48,634	72,724	153,928	205,825
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	66,958	72,362	229,061	219,070
Exploration	15,733	10,669	48,821	42,378
Impairment of proved properties	91	564	153,183	10,130
Abandonment and impairment of unproved properties	4,761	1,231	20,294	4,295
Impairment of materials inventory	2,114	-	13,449	-
General and administrative	20,790	24,145	55,349	67,149
Bad debt expense	-	6,650	-	16,592
Change in Net Profits Plan liability	6,804	(34,867)	(14,038)	46,901
Marketed gas system expense	14,360	22,960	41,352	60,918
Unrealized derivative (gain) loss	4,117	(4,429)	17,251	802
Other expense	968	7,753	12,424	9,155

Total operating expenses	185,330	179,762	731,074	683,215
Income (loss) from operations	457	144,326	(140,869)	359,917
Nonoperating income (expense):				
Interest income	90	239	217	395
Interest expense	(7,565)	(7,026)	(21,324)	(20,862)
Income (loss) before income taxes	(7,018)	137,539	(161,976)	339,450
Income tax benefit (expense)	2,603	(50,542)	61,616	(125,010)
Net income (loss)	$ (4,415)	$ 86,997	$ (100,360)	$ 214,440
Basic weighted-average common shares outstanding	62,505	62,187	62,420	62,254
Diluted weighted-average common shares outstanding	62,505	63,078	62,420	63,327
Basic net income (loss) per common share	$ (0.07)	$ 1.40	$ (1.61)	$ 3.44
Diluted net income (loss) per common share	$ (0.07)	$ 1.38	$ (1.61)	$ 3.39

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

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

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Treasury Stock Shares	Treasury Stock Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
Balances, December 31, 2007 (As adjusted, Note 7)	64,010,832	$ 640	$ 211,913	(1,009,712)	$ (29,049)	$ 876,038	$ (156,968)	$ 902,574
Comprehensive income, net of tax:								
Net income (As adjusted, Note 7)	-	-	-	-	-	87,348	-	87,348
Change in derivative instrument fair value	-	-	-	-	-	-	177,005	177,005
Reclassification to earnings	-	-	-	-	-	-	46,463	46,463
Minimum pension liability adjustment	-	-	-	-	-	-	(1,207)	(1,207)
Total comprehensive income								309,609
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	45,228	-	1,055	-	-	-	-	1,055
Issuance of common stock upon settlement of RSUs following expiration of restriction period, net of shares used for tax	482,602	5	(6,910)	-	-	-	-	(6,905)

withholdings								
Sale of common stock, including income tax benefit of stock option exercises	868,372	9	24,691	-	-	-	-	24,700
Stock-based compensation expense	3,750	-	13,771	23,113	1,041	-	-	14,812
Balances, December 31, 2008 (As adjusted, Note 7)	62,465,572	$ 625	$ 141,283	(176,987)	$ (1,892)	$ 957,200	$ 65,293	$ 1,162,509
Comprehensive loss, net of tax:								
Net loss	-	-	-	-	-	(100,360)	-	(100,360)
Change in derivative instrument fair value	-	-	-	-	-	-	(12,810)	(12,810)
Reclassification to earnings	-	-	-	-	-	-	(57,979)	(57,979)
Minimum pension liability adjustment	-	-	-	-	-	-	4	4
Total comprehensive loss								(171,145)
Cash dividends, $ 0.10 per share	-	-	-	-	-	(6,247)	-	(6,247)
Issuance of common stock under Employee Stock Purchase Plan	49,767	-	858	-	-	-	-	858
Issuance of common stock upon settlement of RSUs following expiration of restriction period, net of shares used for tax withholdings, including income tax cost of RSUs	89,236	1	(3,157)	-	-	-	-	(3,156)
Sale of common stock, including income tax benefit of stock option exercises	33,014	-	320	-	-	-	-	320
Stock-based compensation	1,250	-	12,316	50,094	662	-	-	12,978

expense								
Balances, September 30, 2009	62,638,839	$ 626	$ 151,620	(126,893)	$ (1,230)	$ 850,593	$ (5,492)	$ 996,117

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, 2009	2008 (As adjusted, Note 7)
Cash flows from operating activities:		
Reconciliation of net income (loss) to net cash provided by operating activities:		
Net income (loss)	$ (100,360)	$ 214,440
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
(Gain) loss on divestiture activities	10,632	(54,063)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	229,061	219,070
Exploratory dry hole expense	4,849	6,583
Impairment of proved properties	153,183	10,130
Abandonment and impairment of unproved properties	20,294	4,295
Impairment of materials inventory	13,449	-
Stock-based compensation expense*	12,978	10,477
Bad debt expense	-	16,592
Change in Net Profits Plan liability	(14,038)	46,901
Unrealized derivative loss	17,251	802
Loss related to hurricanes	8,273	6,980
Loss on insurance settlement	-	1,600
Amortization of debt discount and deferred financing costs	8,922	6,942
Deferred income taxes	(69,082)	99,380
Plugging and abandonment	(12,110)	(1,355)
Other	1,432	(3,416)
Changes in current assets and liabilities:		
Accounts receivable	58,844	(39,455)
Refundable income taxes	10,340	(3,650)
Prepaid expenses and other	(8,660)	2,029
Accounts payable and accrued expenses	7,794	34,763
Excess income tax benefit from the exercise of stock options	-	(10,281)
Net cash provided by operating activities	353,052	568,764
Cash flows from investing activities:		

Proceeds from insurance settlement	15,336	-
Proceeds from sale of oil and gas properties	1,137	155,203
Capital expenditures	(292,466)	(495,155)
Acquisition of oil and gas properties	(58)	(83,433)
Receipts from restricted cash	14,398	-
Receipts from short-term investments	1,002	161
Other	-	(9,984)
Net cash used in investing activities	(260,651)	(433,208)
Cash flows from financing activities:		
Proceeds from credit facility	1,898,500	832,000
Repayment of credit facility	(1,963,500)	(947,000)
Debt issuance costs related to credit facility	(11,074)	-
Excess income tax benefit from the exercise of stock options	-	10,281
Proceeds from sale of common stock	1,179	11,327
Repurchase of common stock	-	(77,202)
Dividends paid	(3,120)	(3,076)
Net cash used in financing activities	(78,015)	(173,670)
Net change in cash and cash equivalents	14,386	(38,114)
Cash and cash equivalents at beginning of period	6,131	43,510
Cash and cash equivalents at end of period	$ 20,517	$ 5,396

* Stock-based compensation expense is a component of exploration expense and general and administrative expense on
the consolidated statements of operations. For the nine months ended September 30, 2009, and 2008, respectively,
approximately $4.4 million and $3.8 million of stock-based compensation expense was included in exploration expense.
For the nine months ended September 30, 2009, and 2008, respectively, approximately $8.6 million and $6.7 million of
stock-based compensation expense was included in general and administrative expense.

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

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

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

	For the Nine Months Ended September 30,	
	2009	2008
	(In thousands)	
Cash paid for interest	$ 11,150	$ 14,483
Cash paid (refunded) for income taxes	$ (10,119)	$ 18,943

Dividends of approximately $3.1 million have been declared by the Company's Board of Directors, but not paid, as of September 30, 2009.

In August 2009 and 2008, the Company issued 725,092 and 465,751 Performance Share Awards to employees as equity-based compensation pursuant to the Company's Equity Incentive Compensation Plan. The total fair value of the issuance equaled $25.8 million and $12.3 million respectively.

During the first nine months of 2009 and 2008, the Company issued 241,745 and 427,607 restricted stock units respectively, to employees as equity-based compensation, pursuant to the Company's Equity Incentive Compensation Plan. The total fair value of the issuances was $5.8 million and $23.3 million respectively.

As of September 30, 2009, and 2008, $59.8 million, and $159.5 million, respectively, are included as additions to 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 2009 and 2008 the Company issued 50,094 and 23,113 shares, respectively, of common stock from treasury to its non-employee directors pursuant to the Company's Equity Incentive Compensation Plan. The Company recorded compensation expense related to these issuances of approximately $662,000 and $922,000 for the nine-month periods ended September 30, 2009, and 2008, respectively.

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 will 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.

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, 2009

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 and the instructions to Form 10-Q and Regulation S-X. 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 for the year ended December 31, 2008. 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. In connection with the preparation of the condensed consolidated financial statements of St. Mary and in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 855, "Subsequent Events" ("ASC Topic 855") the Company evaluated subsequent events after the balance sheet date of September 30, 2009, through the filing of this report, November 3, 2009. Please refer to Note 3 – Recent Accounting Pronouncements for additional information regarding ASC.

On January 1, 2009, the adoption of new authoritative accounting guidance under FASB ASC Topic 470-20, "Debt with Conversion and Other Options" ("ASC Topic 470") required retrospective application. As a result, prior period balances presented have been adjusted to reflect the period-specific effects of applying ASC Topic 470. Please refer to Note 7 – Long-term Debt for additional information regarding adoption.

Materials Inventory

The Company's materials inventory is primarily comprised of tubular goods to be used in future drilling or repair operations. Materials inventory is valued at the lower of cost or market and totaled $30.4 million and $40.5 million at September 30, 2009, and December 31, 2008, respectively. The Company incurred net materials inventory write-downs for the three-month and nine-month periods ended September 30, 2009, totaling $2.1 million and $13.4 million, respectively, as a result of the decrease in the value of tubular goods. There were no materials inventory write-downs for the three-month and nine-month periods ended September 30, 2008.

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 for the year ended December 31, 2008, and are supplemented throughout the footnotes of this document. It is suggested that these condensed consolidated financial statements be read in conjunction with the consolidated financial statements and notes included in St. Mary's Annual Report on Form 10-K for the year ended December 31, 2008.

Note 3 – Recent Accounting Pronouncements

New authoritative accounting guidance under FASB ASC Topic 105, "Generally Accepted Accounting Principles" ("ASC Topic 105") establish FASB Accounting Standards Codification as the source of authoritative U.S. GAAP recognized by the FASB to be applied to rules and interpretive releases of the Securities and Exchange Commission ("SEC") under federal securities laws as authoritative GAAP for SEC registrants. ASC Topic 105 supersedes existing FASB, American Institute of Certified Public Accountants, Emerging Issues Task Force and related literature. All other accounting literature is considered non-authoritative. ASC Topic 105 changes the way the Company cites authoritative guidance within the Company's financial statements and accounting policies. The new authoritative guidance under ASC Topic 105 became effective for periods ending on or after September 15, 2009, and did not have a material impact on the Company's consolidated financial statements.

New authoritative accounting guidance under FASB ASC Topic 805, "Business Combinations" ("ASC Topic 805") 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. ASC Topic 805 changes the way the Company accounts for acquisitions of oil and gas properties. Such acquisitions will now be treated as business combinations, which will require transaction costs to be expensed as incurred, may generate gains or losses due to changes between the effective and closing dates of acquisitions, and will require possible recognition of goodwill given differences between the purchase price and fair value of assets received. ASC Topic 805 further amends the initial recognition and measurement, subsequent measurement and accounting, and disclosures of assets and liabilities arising from contingencies in a business combination. The new authoritative guidance under ASC Topic 805 became effective for the Company on January 1, 2009, and the impact on the Company's consolidated financial statements will largely be dependent on the size and nature of the business combinations completed. There have not been any significant acquisitions of oil and gas properties since adoption.

New authoritative accounting guidance under FASB ASC Topic 810, "Consolidation" ("ASC Topic 810") established accounting and reporting standards that require noncontrolling interests to be reported as a component of equity along with any changes in the parent's ownership interest. The new authoritative guidance under ASC Topic 810 became effective for the Company on January 1, 2009, and did not have a material impact on the Company's consolidated financial statements.

New authoritative accounting guidance under FASB ASC Topic 825, "Financial Instruments" ("ASC Topic 825") requires the Company to include disclosures about the fair value of its financial instruments whenever it issues financial information for interim reporting periods and annual reporting periods, whether recognized or not recognized in the statement of financial position. The new authoritative guidance under ASC Topic 825 became effective for the Company on April 1, 2009, and did not have a material impact on the Company's consolidated financial statements.

New authoritative accounting guidance under ASC Topic 855 established general standards of accounting for and disclosures of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. ASC Topic 855 requires companies to disclose the date through which the company evaluated subsequent events, the basis for that date, and whether that date represents the date the financial statements were issued. The new authoritative guidance under ASC Topic

855 became effective for the Company on April 1, 2009, and did not have a material impact on the Company's consolidated financial statements.

In December 2008 the SEC published the final rules and interpretations updating its oil and gas reporting requirements. Many of the revisions are updates to definitions in the existing oil and gas rules to make them consistent with the Petroleum Resource Management System, which was developed by several industry organizations and is a widely accepted standard for the management of petroleum resources. Key revisions include a requirement to use 12-month average pricing rather than year-end pricing for estimating proved reserves, the ability to include nontraditional resources in reserves, the ability to use new technology for determining proved reserves, and permitting disclosure of probable and possible reserves. The new authoritative guidance will be effective for registration statements filed after January 1, 2010, and for annual reports for fiscal years ending on or after December 15, 2009. Early adoption is not permitted. The Company will apply this new authoritative guidance in the Company's Annual Report on Form 10-K for the fiscal year ending December 31, 2009. The Company is currently assessing the impact of this new authoritative guidance on the Company's consolidated financial statements.

Newly proposed authoritative accounting guidance by the FASB would align FASB ASC Topic 932, "Extractive Activities – Oil and Gas" with all of the aforementioned SEC requirements. This proposal is expected to become an issued accounting update within the last quarter of 2009 with an effective date for annual reports for fiscal years ending on or after December 15, 2009. The Company is currently assessing the impact of this new authoritative accounting guidance on the Company's consolidated financial statements.

New authoritative accounting guidance under FASB ASC Topic 715, "Compensation – Retirement Benefits" ("ASC Topic 715") amends the disclosure requirements of plan assets for defined benefit pensions and other postretirement plans. The objective of ASC Topic 715 is to provide users of financial statements with an understanding of how investment allocation decisions are made, the major categories of plan assets held by the plans, the inputs and valuation techniques used to measure the fair value of plan assets, significant concentration of risk within a company's plan assets, fair value measurements determined using significant unobservable inputs, and a reconciliation of changes between the beginning and ending balances. ASC Topic 715 will be effective for fiscal years ending after December 15, 2009. The disclosures required by ASC Topic 715 will be included in the Company's Annual Report on Form 10-K for the fiscal year ending December 31, 2009. The Company is currently assessing the impact of ASC Topic 715 on the Company's consolidated financial statements.

Please refer to Note 7 – Long-term Debt, Note 8 – Derivative Financial Instruments, and Note 11 – Fair Value Measurements for additional information on the recent adoption of new authoritative accounting guidance.

Note 4 – Earnings per Share

Basic net income or loss per common share of stock is calculated by dividing net income or loss 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 or loss per common share of stock is calculated by dividing adjusted net income or loss by the weighted-average 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, unearned 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 Company's 3.50% Senior Convertible Notes have a net-share settlement right whereby each $1,000 principal amount of notes may be surrendered for conversion to cash in an amount equal to the principal amount and, if applicable, shares of common stock or cash or any combination of common stock and cash 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 or nine-month periods ended September 30, 2009, and 2008, respectively.

The Company's PSAs have a three-year performance period. The PSAs represent the right to receive, upon settlement of the PSAs after the completion of the three-year performance period, a number of shares of the Company's common stock that may be from zero to two times the number of PSAs granted on the award date, depending on the extent to which the Company's performance criteria have been achieved and the extent to which the PSAs have vested. The performance criteria for the PSAs are based on a combination of the Company's total shareholder return ("TSR") for the performance period and the relative performance of the Company's TSR compared with the TSR of certain peer companies for the performance period. There were no potentially dilutive shares related to the PSAs included in the diluted earnings per share calculation for the three-month or nine-month periods ended September 30, 2009, and 2008. For additional discussion on the PSAs, please see Note 5 – Compensation Plans under the heading Performance Share Awards Under the Equity Incentive Compensation Plan.

The treasury stock method is used to measure the dilutive impact of stock options, RSUs, 3.50% Senior Convertible Notes, and PSAs. In accordance with FASB ASC Topic 260, "Earnings Per Share" when there is a loss from continuing operations, all potentially dilutive shares will be anti-dilutive. As such, there were no dilutive shares for the three-month or nine-month periods ended September 30, 2009. Unvested RSUs and in-the-money options had a dilutive impact for the three-month and nine-month periods ended September 30, 2008, as calculated in the table below.

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,	
	2009	2008 (As adjusted, Note 7)	2009	2008 (As adjusted, Note 7)
	(In thousands, except per share amounts)			
Net income (loss)	$ (4,415)	$ 86,997	$ (100,360)	$ 214,440
Basic weighted-average common shares outstanding	62,505	62,187	62,420	62,254
Add: dilutive effect of stock options, unvested RSUs, and PSAs	-	891	-	1,073
Add: dilutive effect of 3.50% senior convertible notes	-	-	-	-
Diluted weighted-average common shares outstanding	62,505	63,078	62,420	63,327
	$ (0.07)	$ 1.40	$ (1.61)	$ 3.44

Basic net income (loss) per common share				
Diluted net income (loss) per common share	$ (0.07)	$ 1.38	$ (1.61)	$ 3.39

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Note 5 – Compensation Plans

Cash Bonus Plan

During the first quarters of 2009 and 2008, the Company paid $6.0 million and $3.5 million for cash bonuses earned in the 2008 and 2007 performance years, respectively. Within the general and administrative expense and exploration expense line items in the accompanying consolidated statements of operations was $3.2 million and $2.7 million of cash bonus expense related to the specific performance year for the three-month periods ended September 30, 2009, and 2008, respectively, and $8.5 million and $7.2 million for the nine-month periods ended September 30, 2009, and 2008, respectively.

Performance Share Awards Under the Equity Incentive Compensation Plan

Total stock-based compensation expense related to PSAs for the three-month periods ended September 30, 2009, and 2008, was $3.2 million and $789,000, respectively, and $5.7 million and $789,000 for the nine-month periods ended September 30, 2009, and 2008, respectively. As of September 30, 2009, there was $29.0 million of total unrecognized compensation expense related to unvested PSAs. The unrecognized compensation expense will be amortized through 2012.

A summary of the status and activity of PSAs for the nine-month period ended September 30, 2009, is presented in the following table:

	PSAs		Weighted-Average Grant-Date Fair Value
Non-vested, at January 1, 2009	464,333	$	26.48
Granted	725,092	$	35.59
Vested	(62,562)	$	26.48
Forfeited	(29,400)	$	27.41
Non-vested, at September 30, 2009	1,097,463	$	32.47

The Company granted a total of 725,092 PSAs on August 1, 2009, and recorded compensation expense of $2.2 million for this grant for the three-month period ended September 30, 2009. The fair value of this grant was $25.8 million. The PSAs from this grant represent the right to receive shares of the Company's common stock upon settlement of a three-year performance period ending June 30, 2012. These PSAs vest 1/7th on August 1, 2010, 2/7ths on August 1, 2011, and 4/7ths on August 1, 2012. For additional discussion on the PSAs, please see Note 4 – Earnings per Share.

Restricted Stock Incentive Program Under the Equity Incentive Compensation Plan

Total RSU compensation expense for the three-month periods ended September 30, 2009, and 2008, was $2.1 million and $2.5 million, respectively, and $5.9 million and $8.5 million for the nine-month periods ended September 30, 2009, and 2008, respectively. As of September 30, 2009, there was $12.4 million of total unrecognized compensation expense related to unvested RSU awards. The unrecognized compensation expense will be amortized through 2012.

During the first nine months of 2009, the Company converted 128,427 RSUs, which relate to awards granted in 2008, 2007, and 2006, into shares of the Company's common stock based on the terms or 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 90,486 shares of common stock associated with these grants. The remaining 37,941 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon the delivery of the shares underlying those RSUs.

A summary of the status and activity of non-vested RSUs for the nine-month period ended September 30, 2009, is presented in the following table:

	RSUs	Weighted-Average Grant-Date Fair Value
Non-vested, at January 1, 2009	402,297	$ 48.24
Granted	241,745	$ 23.87
Vested	(122,569)	$ 34.93
Forfeited	(20,671)	$ 52.27
Non-vested, at September 30, 2009	500,802	$ 39.57

As of September 30, 2009, a total of 502,035 RSUs were outstanding, of which 1,233 were vested.

The Company granted a total of 241,745 RSUs on August 1, 2009, and recorded compensation expense of $360,000 for this grant during the three-month period ended September 30, 2009. The fair value of this grant was $5.8 million. Each RSU from this award represents a right to receive one share of the Company's common stock to be delivered upon settlement of the vested RSUs. These RSUs vest 1/7th on August 1, 2010, 2/7ths on August 1, 2011, and 4/7ths on August 1, 2012.

Stock Option Grants Under the Equity Incentive Compensation Plan

The following table summarizes the nine-month activity for stock options outstanding as of September 30, 2009:

	Options	Weighted-Average Exercise Price	Weighted Average Remaining Contractual Term (In years)	Aggregate Intrinsic Value (In thousands)
Outstanding, at January 1, 2009	1,509,710	$ 12.69		
Exercised	(33,014)	$ 9.69		
Forfeited	(45,050)	$ 13.38		
Outstanding, end of period	1,431,646	$ 12.74	2.97	$ 28,228
Vested, or expect to vest, at September 30, 2009	1,431,646	$ 12.74	2.97	$ 28,228
Exercisable, end of period	1,431,646	$ 12.74	2.97	$ 28,228

As of September 30, 2009, there was no unrecognized compensation cost related to unvested stock option awards.

Director Shares

In May 2009 and 2008 the Company issued 50,094 and 23,113 shares, respectively, of the Company's common stock from treasury to the Company's non-employee directors. The shares were issued pursuant to the Company's Equity

Incentive Compensation Plan. The Company recorded $26,000 and $119,000 of compensation expense for the three-month periods ended September 30, 2009, and 2008, respectively, and $662,000 and $922,000 for the nine-month periods ended September 30, 2009, and 2008, respectively.

Employee Stock Purchase Plan

Under the St. Mary Land & Exploration Company Employee Stock Purchase Plan (the “ESPP” or “the Plan”), eligible employees may purchase shares of the Company’s common stock through payroll deductions of up to 15 percent of eligible compensation. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on the first or last day of the purchase period, and shares issued under the ESPP are restricted for a period of 18 months from the date issued. Effective January 1, 2010, shares issued under the ESPP will be restricted for a period of six months. The ESPP is intended to qualify under Section 423 of the Internal Revenue Code. The Company has set aside 2,000,000 shares of its common stock to be available for issuance under the ESPP, of which 1,504,816 shares are available for issuance as of September 30, 2009. The fair value of ESPP grants is measured at the date of grant using the Black-Scholes option-pricing model. There were 49,767 and 17,626 shares issued under the ESPP during the first nine months of 2009 and 2008, respectively. The Company expensed $153,000 and $85,000 for the three-month periods ended September 30, 2009, and 2008, respectively and $694,000 and $250,000 for the nine-month periods ended September 30, 2009, and 2008, respectively based on the estimated fair values on the respective grant dates.

Net Profits Interest Bonus Plan

Under the Company’s Net Profits Interest Bonus Plan (“Net Profits Plan”), all oil and gas wells that were completed or acquired during a year were designated within a specific pool. Key employees of the Company became entitled to payments under the Net Profits Plan based on specific cash flow and cost metrics. The 2007 Net Profits Plan pool was the last pool established by the Company.

Cash payments made under the Net Profits Plan that have been recorded as either general and administrative expense or exploration expense are detailed in the table below:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In thousands)			
General and administrative expense	$ 5,168	$ 9,274	$ 12,942	$ 27,139
Exploration expense	239	1,142	1,116	6,360
Total	$ 5,407	$ 10,416	$ 14,058	$ 33,499

Additionally, the Company made cash payments under the Net Profits Plan of $12.4 million for the nine-month period ended September 30, 2008, as a result of sales proceeds from the Abraxas and Greater Green River Basin divestitures. The cash payments are accounted for as a reduction in the gain (loss) on divestiture activity in the accompanying consolidated statements of operations. There were no cash payments made under the Net Profits Plan during the third quarter of 2008 or during the first three quarters of 2009 as a result of divestitures that have been accounted for as a reduction in the gain (loss) on divestiture activity.

The Company records changes in the present value of estimated future payments under the Net Profits Plan as a separate line item in the accompanying unaudited consolidated statements of operations. The change in the estimated liability is recorded as a non-cash expense or benefit in the current period. The amount recorded as an expense or benefit associated with the change in the estimated liability is not allocated to general and administrative expense or exploration expense because it is associated with the future net cash flows from oil and gas properties in the respective pools rather than results being realized through current period production. The table below presents the estimated allocation of the change in the liability if the Company did allocate the adjustment to these specific functional line items based on the current allocation of actual distributions made by the Company. As time progresses, less of the distributions relate to prospective exploration efforts as more of the distributions are made to employees that have terminated employment and do not provide ongoing exploration support.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In thousands)			
General and administrative expense (benefit)	$ 5,807	$ (25,291)	$ (12,923)	$ 37,997
Exploration expense (benefit)	997	(9,576)	(1,115)	8,904
Total	$ 6,804	$ (34,867)	$ (14,038)	$ 46,901

Note 6 – Income Taxes

Income tax expense (benefit) for the three-month and nine-month periods ended September 30, 2009, and 2008, differs from the amounts that would be provided by applying the statutory U.S. federal income tax rate to income (loss) 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,	
	2009	2008	2009	2008
	(In thousands)			
Current portion of income tax expense:				
Federal	$ 2,881	$ 5,415	$ 6,129	$ 24,155
State	451	509	1,337	1,475
Deferred portion of income tax expense (benefit)	(5,935)	44,618	(69,082)	99,380
Total income tax expense (benefit)	$ (2,603)	$ 50,542	$ (61,616)	$ 125,010
Effective tax rates	37.1%	36.7%	38.0%	36.8%

A change in the Company's effective 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. Current low commodity prices and uncertain future pricing are causing the rate to vary from period to period as estimates for the domestic production activities deduction, percentage depletion, the impact of potential permanent state differences, and the impact of net operating loss carrybacks effect the periods presented differently.

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 2006. The Internal Revenue Service completed its 2005 audit in March 2009 and refunded the Company $278,000 plus interest of $41,000. Related amended State income tax returns were filed in the second quarter of 2009. There was no change to the provision for income tax expense as a result of the examination. The Company received $980,000 in the first quarter of 2008 for income tax refunds and accrued interest resulting from a carry-over of minimum tax credits to its 2003 tax year.

Note 7 – Long-term Debt

Revolving Credit Facility

The Company executed a Third Amended and Restated Credit Agreement on April 14, 2009. This amended revolving credit facility replaced the previous facility. The Company incurred $11.1 million of deferred financing costs in association with the amended credit facility. 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. The credit facility specifies a maximum loan amount of $1.0 billion and has a maturity date of July 31, 2012. The authorized borrowing base under the credit facility 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. On September 29, 2009, the lending group redetermined and maintained the Company's reserve-backed borrowing base under the credit facility at an amount of $900 million. The Company has an aggregate commitment amount of $678 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 as of September 30, 2009, and through the date of this filing. Interest and commitment fees are accrued based on the borrowing base utilization grid below. Eurodollar loans accrue interest at the London Interbank Offered Rate ("LIBOR") plus the applicable margin from the utilization table, and Alternative Base Rate ("ABR") and swingline loans accrue interest at Prime plus the applicable margin from the utilization table. Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the accompanying consolidated statements of operations.

Borrowing Base Utilization Grid

Borrowing Base Utilization Percentage	<25%	>25% <50%	>50% <75%	>75%
Eurodollar Loans	2.000%	2.250%	2.500%	2.750%
ABR Loans or Swingline Loans	1.000%	1.250%	1.500%	1.750%
Commitment Fee Rate	0.500%	0.500%	0.500%	0.500%

The Company had $235.0 million and $215.0 million outstanding under its revolving credit agreement as of September 30, 2009, and October 27, 2009, respectively. The Company had $441.7 million and $462.4 million of available borrowing capacity under this facility as of September 30, 2009, and October 27, 2009, respectively. The Company has a single letter of credit outstanding in the amount of $1.3 million and $569,000 as of September 30, 2009, and October 27, 2009, respectively. This letter of credit reduces the amount available under the commitment amount on a dollar-for-dollar basis.

New authoritative accounting guidance under FASB ASC Topic 470

Effective January 1, 2009, the new authoritative accounting guidance under ASC Topic 470 required issuers of convertible debt that may be settled fully or partially in cash upon conversion to account separately for the liability and equity components of the debt in a manner that reflects the entity's nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. ASC Topic 470 applies to the Company's 3.50% Senior Convertible Notes. Under the adoption provisions of ASC Topic 470, the Company retrospectively applied its provisions and restated the Company's consolidated financial statements for prior periods.

Under the provisions of ASC Topic 470, $42.0 million of the carrying value of the 3.50% Senior Convertible Notes was recorded as additional paid-in capital as of the April 4, 2007 issuance date. This amount represents the equity component of the proceeds from the 3.50% Senior Convertible Notes, calculated assuming a 7.0% discount rate, which is the estimate of what the Company’s borrowing rate for a similar debt instrument without the conversion feature would have been at the date of the issuance of the 3.50% Senior Convertible Notes. Upon retrospective application, the adoption resulted in a $6.8 million decrease in the Company's retained earnings at December 31, 2008, which was comprised of non-cash interest expense of $10.8 million, net of capitalized interest of $2.2 million, less deferred taxes of $4.0 million, for the period from April 4, 2007, through December 31, 2008. The following table presents the December 31, 2008, consolidated balance sheet line items affected as adjusted and as originally reported:

	December 31, 2008	
	As Adjusted	As Originally Reported
	(In thousands)	
Proved oil and gas properties	$ 2,969,722	$ 2,967,491
3.50% Senior Convertible Notes	258,713	287,500
Noncurrent deferred income taxes	354,328	358,334
Additional paid-in capital	141,283	99,440
Retained earnings	957,200	964,019

As of September 30, 2009, and December 31, 2008, the carrying value of the equity component was $42.0 million. The principal amount of the 3.50% Senior Convertible Notes, the unamortized debt discount, and the net carrying amounts were as follows:

	As of September 30, 2009	As of December 31, 2008 (Adjusted)
	(In thousands)	
3.50% Senior Convertible Notes	$ 287,500	$ 287,500
Unamortized debt discount	(22,716)	(28,787)
Net carrying amount of the 3.50% Senior Convertible Notes	$ 264,784	$ 258,713

The Company amortized $2.0 million and $1.9 million of the debt discount for the three months ended September 30, 2009, and 2008, respectively, and $6.0 million and $5.7 million for the nine months ended September 30, 2009, and 2008, respectively. Accumulated amortization related to the debt discount was $19.1 million as of September 30, 2009. The remaining unamortized debt discount will be amortized under the interest method over the next 30 months.

The consolidated statements of operations were retroactively adjusted compared to previously reported amounts as follows:

	For the Three Months Ended September 30, 2008		For the Nine Months Ended September 30, 2008	
	As Adjusted	As Originally Reported	As Adjusted	As Originally Reported
	(In thousands except per share amounts)			
Interest expense	$ 7,026	$ 5,359	$ 20,862	$ 15,858
Income tax expense	50,542	51,159	125,010	126,861
Net income	86,997	88,047	214,440	217,593
Basic net income per common share	$ 1.40	$ 1.42	$ 3.44	$ 3.50
Diluted net income per common share	$ 1.38	$ 1.40	$ 3.39	$ 3.44

Note 8 – Derivative Financial Instruments

New authoritative accounting guidance under FASB ASC Topic 815

Effective January 1, 2009, new authoritative accounting guidance under FASB ASC Topic 815, “Derivatives and Hedging” (“ASC Topic 815”) requires entities to provide greater transparency about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for, and how derivative instruments and related hedged items affect an entity’s financial position, results of operations, and cash flows.

Oil and Natural Gas Commodity Hedges

To mitigate a portion of the potential exposure to adverse market changes in oil and gas prices and the associated impact on cash flows, the Company has entered into various derivative contracts. The Company’s derivative contracts in place include swap and collar arrangements for oil, natural gas, and natural gas liquids (“NGL”). As of September 30, 2009, the Company has hedge contracts in place through the third quarter of 2012 for a total of approximately 7 million Bbls of anticipated crude oil production, 45 million MMBtu of anticipated natural gas production, and 230,000 Bbls of anticipated natural gas liquids production. As of October 27, 2009, the Company has hedge contracts in place through the third quarter of 2012 for a total of approximately 7 million Bbls of anticipated crude oil production, 57 million MMBtu of anticipated natural gas production, and 946,000 Bbls of anticipated natural gas liquids production.

The Company attempts to qualify its oil and gas derivative instruments as cash flow hedges for accounting purposes under ASC Topic 815. The Company formally documents all relationships between the derivative instruments and the hedged production, as well as the Company’s risk management objective and strategy for the particular derivative contracts. This process includes linking all derivatives that are designated as cash flow hedges to the specific forecasted sale of oil or gas at its physical location. The Company also formally assesses (both at the derivative’s inception and on an ongoing basis) whether the derivatives being utilized have been highly effective in 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 for that derivative prospectively. If hedge accounting is discontinued and the derivative remains outstanding, the Company will recognize all subsequent changes in its fair value in the

Company's consolidated statements of operations for the period in which the change occurs. As of September 30, 2009, all oil and natural gas derivative instruments qualified as cash flow hedges for accounting purposes. The

Company anticipates that all forecasted transactions will occur by the end of their originally specified periods. All contracts are entered into for other than trading purposes.

The Company's oil and gas hedges are measured at fair value and are included in the accompanying consolidated balance sheets as accrued derivative assets and liabilities. The Company derives internal valuation estimates taking into consideration the counterparties' credit worthiness, the Company's credit worthiness, and the time value of money. Those internal valuations are then compared to the counterparties' mark-to-market statements. The consideration of the factors results in an estimated exit-price for each derivative 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. The derivative instruments utilized by the Company are not considered by management to be complex, structured, or illiquid. The oil and gas derivative markets are highly active. The fair value of oil and natural gas derivative contracts designated and qualifying as cash flow hedges under ASC Topic 815 was a net liability of $25.6 million and a net asset of $105.3 million at September 30, 2009, and December 31, 2008, respectively.

The following table details the fair value of derivatives recorded in the consolidated balance sheets, by category:

	Location on Consolidated Balance Sheets	Fair Value at September 30, 2009	Fair Value at December 31, 2008
Derivative assets designated as cash flow hedges:		(In thousands)	
Oil, natural gas, and NGL commodity	Current assets	$ 41,428	$ 111,649
Oil, natural gas, and NGL commodity	Other noncurrent assets	4,614	21,541
Total derivative assets designated as cash flow hedges under ASC Topic 815		$ 46,042	$ 133,190
Derivative liabilities designated as cash flow hedges:			
Oil, natural gas, and NGL commodity	Current liabilities	$ (25,370)	$ (501)
Oil, natural gas, and NGL commodity	Noncurrent liabilities	(46,315)	(27,419)
Total derivative liabilities designated as cash flow hedges under ASC Topic 815		$ (71,685)	$ (27,920)

Realized gains or losses from the settlement of oil and gas derivative contracts are reported in the operating revenues and other income section of the accompanying consolidated statements of operations. The Company realized a net gain of $28.3 million and a net loss of $53.5 million from its oil and natural gas derivative contracts for the three months ended September 30, 2009, and 2008, respectively, and realized a net gain of $127.2 million and a net loss of $145.8 million from its oil and natural gas derivative contracts for the nine months ended September 30, 2009, and 2008, respectively.

After-tax changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributed to the hedged risk, are recorded in accumulated other comprehensive income in the accompanying consolidated balance sheets until the hedged item is realized in earnings upon the sale of the associated hedged production. As of September 30, 2009, the amount of unrealized gain net of deferred income taxes to be reclassified from accumulated other comprehensive income to realized oil and gas hedge gain (loss) in the Company's accompanying consolidated statements of operations in the next twelve months is $15.7 million.

The Company seeks to minimize ineffectiveness by entering into oil derivative contracts indexed to the New York Mercantile Exchange West Texas Intermediate ("NYMEX WTI") index and natural gas derivative contracts indexed to regional index prices associated with pipelines in proximity to the Company's areas of production. As the Company's derivative contracts contain the same index as the Company's sales contracts, this results in derivative contracts that are highly correlated with the underlying hedged item.

The following table details the effect of derivative instruments on other comprehensive income (loss) and the consolidated balance sheets (net of tax):

	Derivatives Qualifying as Cash Flow Hedges	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2009	2008	2009	2008
		(In thousands)			
Amount of (Gain) Loss on Derivatives Recognized in OCI During the Period (Effective Portion)	Commodity hedges	$ 958	$ (400,419)	$ 12,810	$ 51,474
Amount of (Gain) Loss Reclassified from AOCI to Realized Oil and Gas Hedge Gain (Loss) (Effective Portion)	Commodity hedges	$ (12,485)	$ (21,522)	$ (57,979)	$ 37,176

Any change in fair value resulting from hedge ineffectiveness is recognized currently in unrealized derivative (gain) loss in the accompanying consolidated statements of operations. The following table details the effect of derivative instruments on the consolidated statements of operations:

Derivatives Qualifying as Cash Flow Hedges	Classification of (Gain) Loss Recognized in Earnings	(Gain) Loss Recognized in Earnings (Ineffective Portion)			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2009	2008	2009	2008
		(In thousands)			
Commodity hedges	Unrealized derivative (gain) loss	$ 4,117	$ (4,429)	$ 17,251	$ 802

Credit Related Contingent Features

As of September 30, 2009, only two of the Company's hedge counterparties were not members of the Company's credit facility bank syndicate. Member banks are secured by the Company's oil and gas assets, and so do not require the Company to post collateral in hedge liability instances. When the Company is in a liability position with a non-member bank, posting of collateral may be required if the

Company's liability balance exceeds the limit set forth in the agreement with the non-member bank. With one of the non-member banks, the Company is subject to financial ratio tests, which determine the liability balance above which the Company has to post cash collateral. With the other non-member bank, the Company is required to post collateral if the liability balance exceeds $5.0 million. The Company had $1.1 million of collateral posted with non-member banks as of September 30, 2009. No collateral was posted as of October 27, 2009.

Subsequent to September 30, 2009, the Company novated all of the commodity hedges that it had with one of the non-member banks to a bank that is a member of the Company's credit facility bank syndicate. Per the terms of the novation agreement, the non-member bank returned all of the cash that the Company had posted as collateral.

Convertible Note Derivative Instruments

The contingent interest provision of the 3.50% Senior Convertible Notes is a derivative instrument. As of September 30, 2009, and December 31, 2008, the value of this 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 for Both Plans

The following table presents the total 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,	
	2009	2008	2009	2008
	(In thousands)			
Service cost	$ 625	$ 460	$ 1,875	$ 1,379
Interest cost	234	222	701	665
Expected return on plan assets	(108)	(168)	(323)	(503)
Amortization of net actuarial loss	93	40	279	121
Net periodic benefit cost	$ 844	$ 554	$ 2,532	$ 1,662

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

Under the Pension Protection Act of 2006 St. Mary is required to contribute at least $380,000 to the Pension Plans in 2009. However, the Company contributed $1.9 million in September 2009 based upon the preliminary funding results analysis completed in April 2009 to maintain an adequate funding level to provide retirement benefits to current and future plan participants and maintain an adequate funding level to provide lump sum payments if elected by a participant.

Note 10 – Asset Retirement Obligations

The Company recognizes an estimated liability for future costs associated with the plugging and abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and a corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is completed or acquired. The increase in carrying value is included in proved oil and gas properties in the accompanying consolidated balance sheets. The Company depletes the amount added to proved oil and gas property costs and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and gas properties. Cash paid to settle asset retirement obligations is included in the operating section of the Company's accompanying consolidated statements of cash flows.

The Company's estimated asset retirement obligation liability is based on estimated economic lives, historical experience in plugging and abandoning wells, estimated cost to plug and 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 6.5 percent to 12.0 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,	
	2009	2008	2009	2008
	(In thousands)			
Beginning asset retirement obligation	$ 123,251	$ 106,486	$ 116,274	$ 108,284
Liabilities incurred	167	1,073	707	7,162
Liabilities settled	(974)	(4,039)	(6,150)	(16,509)
Accretion expense	2,460	1,954	6,970	5,337
Revision to estimated cash flow	2,617	6,373	9,720	7,573
Ending asset retirement obligation	$ 127,521	$ 111,847	$ 127,521	$ 111,847

As of September 30, 2009, the Company had $23.7 million of asset retirement obligation associated with the oil and gas properties held for sale included in a separate line item on the Company's accompanying consolidated balance sheets. Additionally, as of September 30, 2009, accounts payable and accrued expenses contained $35.1 million related to the Company's current asset retirement obligation liability associated with the estimated retirement of some of the Company's offshore platforms.

The Company recorded a loss related to hurricanes, included in the other expense line item within the accompanying consolidated statements of operations, of $1.2 million and $7.0 million for the three-month periods ended September 30, 2009, and 2008, respectively, and $8.3 million and $7.0 million for the nine-month periods ended September 30, 2009, and 2008, respectively. The loss primarily relates to the Vermilion 281 platform that was lost in Hurricane Ike.

Note 11 – Fair Value Measurements

On January 1, 2008, the Company partially applied new authoritative accounting guidance under FASB ASC Topic 820, "Fair Value Measurements and Disclosures" ("ASC Topic 820") for all financial assets and liabilities measured at fair value on a recurring basis. The topic establishes a framework for measuring fair value and requires enhanced disclosures about fair value measurements. ASC Topic 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The topic 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 topic establishes a hierarchy for grouping these assets and liabilities, based on the significance level of the following inputs:

- Level 1 – Quoted prices in active markets for identical assets or liabilities

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

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

On January 1, 2009, the Company applied ASC Topic 820 for all nonfinancial assets and liabilities measured at fair value on a nonrecurring basis, including long-lived assets and assets held for sale measured at fair value under FASB ASC Topic 360, "Property, Plant, and Equipment" ("ASC Topic 360") and asset retirement obligations initially measured at fair value under FASB ASC Topic 410, "Asset Retirement and Environmental Obligations" ("ASC Topic 410"). The adoption of ASC Topic 820 for nonfinancial assets and liabilities did not have a material impact on the Company's financial statements.

There were no nonfinancial assets or liabilities measured at fair value as of September 30, 2009. The following is a listing of the Company's financial assets and liabilities that are measured at fair value on a recurring basis and where they are classified within the hierarchy as of September 30, 2009:

	Level 1	Level 2	Level 3
		(In thousands)	
Assets:			
Accrued derivative	$ -	$ 46,042	$ -
Liabilities:			
Accrued derivative	$ -	$ 71,685	$ -
Net Profits Plan	$ -	$ -	$ 163,328

The following is a listing of the Company's financial assets and liabilities that are measured at fair value on a recurring basis and where they are classified within the hierarchy as of December 31, 2008:

	Level 1	Level 2	Level 3
		(In thousands)	
Assets:			
Accrued derivative	$ -	$ 133,190	$ -
Liabilities:			
Accrued derivative	$ -	$ 27,920	$ -
Net Profits Plan	$ -	$ -	$ 177,366

Both financial and nonfinancial assets and liabilities are categorized within the hierarchy based on the lowest level of input that is significant to the fair value measurement. The 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. Fair values are based upon interpolated data. The Company calculates internal valuation estimates taking into consideration the counterparties' credit ratings, the Company's credit rating, and the time value of money.

These valuations are then compared to the respective counterparties' mark-to-market statements. The considered factors result in an estimated exit-price that management believes provides a reasonable and consistent methodology for valuing derivative instruments.

Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. However, 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 credit ratings of its counterparties and may ask counterparties to post collateral if their ratings deteriorate. In some instances the Company will attempt to novate the trade to 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 facility margins, and any change in such margins since the last measurement date. The majority of the Company's derivative counterparties are members of St. Mary's credit facility bank syndicate.

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 ASC Topic 820 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.

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 expected future cash flow 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 risk premium, and nonperformance risk to calculate the fair value. There is a direct correlation between realized oil and gas commodity prices driving net cash flows and the Net Profits Plan liability. If commodity prices fall, 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 during the prior 24 months together with adjusted NYMEX strip prices for the ensuing 12 months. This average price is adjusted to include the effect of hedge prices for the percentage of forecasted production hedged in the relevant periods. The forecasted non-cash expense associated with this significant management estimate is highly volatile from period to period due to fluctuations that occur in the crude oil and natural gas commodity markets. 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.

If the commodity prices used in the calculation changed by five percent, the liability recorded at September 30, 2009, would differ by approximately $13 million. A one percentage point decrease in the discount rate would result in an increase to the liability of approximately $8 million, while a one percentage point increase in the discount rate would result in a decrease to the liability of approximately $7 million. Actual cash payments to be made to participants in future periods are dependent on actual production, realized commodity 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 management estimates as described within this footnote. While some inputs to the Company's calculation of fair value on 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, 2009, and 2008, respectively.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In thousands)			
Beginning balance	$ 156,524	$ 293,174	$ 177,366	$ 211,406
Net increase (decrease) in liability (a)	12,211	(24,451)	20	92,832
Net settlements (a)(b)	(5,407)	(10,416)	(14,058)	(45,931)
Transfers in (out) of Level 3	-	-	-	-
Ending balance	$ 163,328	$ 258,307	$ 163,328	$ 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 under the Net Profits Plan.

3.50% Senior Convertible Notes Due 2027

Based on the market price of the 3.50% Senior Convertible Notes, the estimated fair value of the notes was approximately $284.6 million and $204.0 million as of September 30, 2009, and December 31, 2008, respectively.

Proved Oil and Gas Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value if the sum of the expected undiscounted future cash flows is less than net book value pursuant to ASC Topic 360. The Company uses Level 3 inputs and the income valuation technique, which converts future amounts to a single present value amount, to measure the fair value of proved properties through an application of discount rates and price forecasts selected by the Company's management. The discount rate is a rate that management believes is representative of current market conditions and includes the following factors: estimate of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. The price forecast is based on NYMEX strip pricing, adjusted for basis differentials, for the first five years. Future operating costs are also adjusted as deemed appropriate for these estimates.

There were no long-lived assets measured at fair value within the accompanying consolidated balance sheets at September 30, 2009. The provisions under ASC Topic 820 were applied to nonfinancial assets and liabilities, as previously discussed above, on January 1, 2009.

Asset Retirement Obligations

The Company estimates asset retirement obligations pursuant to the provisions of ASC Topic 410. The income valuation technique is utilized by the Company to determine the fair value of the liability at the point of inception by applying a credit-adjusted risk-free rate, which takes into account the Company's credit risk, the time value of money, and the current economic state, to the undiscounted expected abandonment cash flows. Given the unobservable nature of the inputs the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. There were no asset retirement obligations measured at fair value within the accompanying consolidated balance sheets at September 30, 2009. The provisions under ASC Topic 820 were applied to nonfinancial assets and liabilities, as previously discussed above, on January 1, 2009.

Refer to Note 8 – Derivative Financial Instruments and Note 10 – Asset Retirement Obligations for more information regarding the Company's hedging instruments and asset retirement obligations.

Note 12 – Impairment of Proved and Unproved Properties

The Company recorded $153.2 million of proved property impairments during the first nine months of 2009. The Company recorded $147.0 million of proved property impairments during the first quarter of 2009. A significant decrease in the market price for natural gas, including differentials in effect at March 31, 2009, caused the majority of this non-cash impairment of proved properties in the first quarter. The largest portion of the impairment was $97.3 million related to assets located in the Mid-Continent region which were impacted by wider than normal differentials for that period. During the second quarter of 2009, the Company incurred an additional impairment on proved properties of $6.0 million related to the write-down of certain assets located in the Gulf of Mexico in which the Company is relinquishing its ownership interests. The Company recorded $564,000 and $10.1 million of proved property impairments, respectively, for the three-month and nine-month periods ended September 30, 2008, the latter of which included $9.6 million related to the write-down of assets located in the Apple Springs Field in Louisiana.

The Company recorded $4.8 million and $20.3 million of abandonment and impairment of unproved properties during the three-month and nine-month periods ended September 30, 2009, respectively. The largest portion of this impairment related to the Floyd Shale acreage located in Mississippi. The Company recorded $1.2 million and $4.3 million of abandonment and impairment of unproved properties for the three-month and nine-month periods ended September 30, 2008, respectively.

Note 13 – Assets Held for Sale

In accordance with ASC Topic 360, assets are classified as held for sale when the Company commits to a plan to sell the assets and there is reasonable certainty that the sale will take place within one year. Upon classification as held-for-sale, long-lived assets are no longer depreciated or depleted and a measurement for impairment is performed to expense any excess of carrying value over fair value less costs to sell. Subsequent changes to estimated 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.

As of September 30, 2009, the accompanying consolidated balance sheets present $148.9 million in book value of assets held for sale, net of accumulated depletion, depreciation, and amortization. The corresponding asset retirement obligation liability of $23.7 million is also separately presented. The Company determined that these sales do not qualify for discontinued operations accounting. The above assets held for sale and asset retirement obligation liability amounts include a new package of certain non-core properties located primarily in the Rocky Mountain region that the Company began marketing in the third quarter of 2009.

In the third quarter of 2009, St. Mary reclassified a portion of the assets previously classified as held for sale to assets held and used, as these assets were no longer being actively marketed. In accordance with

ASC Topic 360, the Company must measure the assets at the lower of the assets carrying amount before the assets were classified as held for sale, adjusted for any depreciation and depletion expense that would have been recognized had the assets been continuously classified as held and used, or the assets fair value at the subsequent date that the decision not to actively market the assets was determined. As a result of this measurement the Company recognized a $9.8 million loss on unsuccessful sale of properties, which is included within the gain (loss) on divestiture activity line item within the accompanying consolidated statements of operations.

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

This discussion and analysis 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. The prior year balances within the accompanying financial statements and notes have been adjusted to reflect the accounting required under ASC Topic 470. Please refer to Note 7 – Long-term Debt within Part I, Item 1 of this report for additional discussion.

Overview of the Company, Highlights, and Outlook

General Overview

We are an independent energy company focused on the development, exploration, exploitation, acquisition, and production of natural gas and crude oil in North America. We generate nearly all our revenues and cash flows from the sale of produced natural gas and crude oil. Our oil and gas reserves and operations are concentrated primarily in various Rocky Mountain basins, including the Williston, Big Horn, Wind River, Powder River, and Greater Green River basins; the Mid-Continent Anadarko and Arkoma basins; the Permian Basin; the productive formations of East Texas and North Louisiana; the Maverick Basin in South Texas; and the onshore Gulf Coast. We have developed a balanced and diverse portfolio of proved reserves, development drilling opportunities, and potential resource plays.

Our mission is to deliver outstanding net asset value per share growth to our investors via attractive oil and gas investments. Historically, we relied on a strategy of growing through niche acquisitions focused in the continental United States. Over the last few years, we have shifted our strategy to focus on capturing potential resource plays earlier and at a lower cost of entry. This shift was due to the fact that, as we grew, the universe of potential niche acquisition targets became smaller, more expensive, and less impactful to our growth. We believe this shift will allow for more stable and predictable production and proved reserve growth. Going forward, we will focus on continuing to acquire significant leasehold positions in existing and emerging resource plays in North America. Our strategy can be summarized as follows:

- Acquire significant leasehold positions in new and emerging North American resource plays
- Leverage our core competencies in drilling, completing, and acquiring oil and gas assets
- Exploit our significant legacy asset production and optimize our asset base through divestitures of non-core assets when appropriate
- Maintain a strong balance sheet while funding the growth of the enterprise.

Financial Standing and Liquidity

During and subsequent to the third quarter of 2008, specific issues related to the financial sector rippled through the broader economy. The failure or takeovers of several large financial institutions adversely impacted the wider equity, debt, and credit markets. Financial strength and liquidity became increasingly important as investors considered the ability of companies to fund their planned levels of activity and to service their debt obligations. In addition, fears of prolonged weakness in the global economy leading to anemic energy demand resulted in a significant decline in oil and natural gas prices. As a result of these events, we entered 2009 with a business plan designed to operate within our operating cash flow. We have maintained a disciplined approach with our capital investments during the year, which, combined with higher operating cash flows than we anticipated originally, have allowed us to maintain our strong financial position and pay down borrowings under our credit facility. We expect our 2009 exploration and development program budget will be at or near our 2009 operating cash flows. Accordingly, we do not anticipate accessing the equity or public debt markets for the remainder of 2009.

We continue to believe we have adequate liquidity available to us through our credit facility as discussed below under the caption Overview of Liquidity and Capital Resources.

Oil and Gas Prices

Our financial condition and the results of our operations 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 a given 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 either the average of 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 quarters of 2009 and 2008 and the second quarter of 2009:

	For the Three Months Ended		
	September 30, 2009	June 30, 2009	September 30, 2008
Crude Oil (per Bbl):			
Average NYMEX price	$ 68.30	$ 59.62	$ 117.98
Realized price, before the effects of hedging	$ 61.93	$ 53.96	$ 111.97
Net realized price, including the effects of hedging	$ 62.65	$ 56.72	$ 83.30
Natural Gas (per Mcf):			
Average NYMEX price	$ 3.41	$ 3.72	$ 10.09
Realized price, before the effects of hedging	$ 3.37	$ 3.07	$ 9.96
Net realized price, including the effects of hedging	$ 4.95	$ 5.19	$ 9.51

Average quarterly NYMEX crude oil prices increased 15 percent from the second quarter of 2009 to the third quarter of 2009 from $59.62 per barrel to $68.30 per barrel. The 36-month forward strip price for crude oil was $76.20 per barrel at the end of the third quarter of 2009 compared with $76.46 per barrel at the end of the second quarter of 2009. On October 27, 2009, the 36-month forward strip price had increased from the end of the third quarter 2009 by 12 percent to $85.08 per barrel. At the same time, the near month price was $79.55 per barrel, which was 13 percent higher than the September 30, 2009, near month price of $70.61 per barrel.

Average quarterly NYMEX natural gas prices decreased eight percent from the second quarter of 2009 to the third quarter of 2009 from $3.72 per Mcf to $3.41 per Mcf. Natural gas prices have been under downward pressure due to concerns regarding high levels of natural gas in storage and concerns of a perpetual amount of excess supply in the market, as well as declining U.S. demand for natural gas. The 36-month forward strip price for natural gas increased four percent to $6.58 per MMBtu at the end of the third quarter of 2009 compared with $6.33 per MMBtu at the end of the second quarter of 2009, largely due to improving sentiment regarding the economic outlook in the U.S. economy. As of October 27, 2009, the 36-month forward strip price had decreased three percent to $6.40 per MMBtu. At the same time, the near month price had decreased from the September 30, 2009, near month price of $4.84 per MMBtu by an additional six percent to $4.56 per MMBtu.

While changes in quoted NYMEX oil and natural gas prices are generally used as a basis for comparison within our industry, the price we receive for oil and natural gas is affected by quality, energy content, location, and transportation differentials for these products. We refer to this price as our realized price, which excludes the effects of hedging. Our realized price is further impacted by the results of our hedging arrangements that are settled in the respective periods. We refer to this price as our net realized price. Our net natural gas and oil price realizations for the three months ended September 30, 2009, were positively impacted by $27.2 million and $1.1 million of realized hedge gains, respectively. Net natural gas and oil price realizations for the nine months ended September 30, 2009, were positively impacted by $105.6 million and $21.6 million of realized hedge gains, respectively.

Hedging Activities

Hedging is an important part of our financial risk management program. The amount of production we hedge is driven by the amount of debt on our consolidated balance sheet and the level of capital commitments and long-term obligations we have in place. In the case of a significant acquisition of producing properties, we will consider hedging a portion of the acquired production in order to protect the economics assumed in the acquisition. With the hedges we have in place, we believe we have established a base cash flow stream for our future operations, and our use of collars for a portion of the hedges allows us to participate in upward movements in oil and gas prices. Please see Note 8 – Derivative Financial Instruments of 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.

We attempt to qualify our oil and gas derivative instruments as cash flow hedges for accounting purposes under ASC Topic 815. Changes in the value of our hedge positions are primarily reflected in our consolidated balance sheets. A portion of the change in the value of our hedge positions is recognized in our consolidated statements of operations due to the hedges being partially ineffective. We recognized $4.1 million in non-cash derivative loss in the third quarter of 2009. This was primarily caused by increases in the price of oil causing what had previously been hedge assets to become hedge liabilities, which in turn resulted in ineffectiveness losses from these hedge liabilities.

The U.S. Congress is currently considering recent proposals to increase the regulatory oversight of the over-the-counter derivatives markets in order to promote more transparency in those markets. Although we cannot predict the ultimate outcome of these proposals, new regulations in this area may result in increased costs and cash collateral requirements for the types of oil and gas derivative instruments we use to hedge and otherwise manage our financial risks related to swings in oil and gas commodity prices.

Third Quarter 2009 Highlights

Developments in emerging resource plays. During 2008, the Haynesville shale, the Eagle Ford shale, and the Marcellus shale resource plays emerged as significant new sources of gas supply for the exploration and production industry. We have exposure to each of these plays that, if successful, could provide for significant future organic growth in reserves and production. The Haynesville shale emerged early in 2008 in northern Louisiana and eastern Texas and quickly became the most active resource play in the country. Our position was built as a result of earlier leasing activity targeting the James Lime and Cotton Valley formations. Our Eagle Ford shale position in the Maverick Basin in South Texas was built from 2007 through 2009 through a combination of property acquisitions, leasing activity, and participation in a joint venture with industry partners. Late in 2008 we entered into arrangements that allow us to earn or purchase acreage in the Marcellus shale in north central Pennsylvania.

During the third quarter of 2009, we announced we would be increasing the number of wells planned for the Eagle Ford shale from four wells to ten wells on our operated high working interest acreage. Results from the completed wells to date have been positive. As of the date of this filing, we have publicly reported production information related to our first four wells across our high working interest leasehold position and these initial production rates have been encouraging to us. We are proceeding with our previously announced program and will be adding a second operated rig to drill on this high working interest acreage in the fourth quarter of 2009. Our expectation is that we will operate two rigs in this part of the play for the foreseeable future. Also during the third quarter, we drilled and completed three wells on joint venture acreage where we have two industry partners. There is a shortage of sales infrastructure in this area which we believe has limited the ability to fully evaluate these wells at this time. We continue to work with our partners in the play and are committed to participating in the joint venture going forward. Between the joint venture and our other acreage holding, we currently have a total of approximately 225,000 net acres with potential for the Eagle Ford shale in Dimmitt, LaSalle, Maverick, and Webb counties in Texas. We continue to evaluate ways to increase our leasehold position across the play.

During the quarter, we completed our second well targeting the Haynesville shale in northern San Augustine County, Texas. The well was cored and logged, then completed vertically. We view the production rate and core data from this well positively since we think it could have favorable implications to the horizontal development in this part of the Haynesville shale trend. In addition, offsetting industry activity in this part of East Texas appears encouraging. We are drilling our second well in the area, in southern Shelby County, Texas, and we plan to complete this well vertically. We have an ongoing program to shoot, acquire, and interpret 3D seismic data over a large part of our East Texas acreage, which we expect will be completed in the first quarter of 2010. We think seismic data will be important to the successful horizontal development of this play. We continue to participate with partners in non-operated wells in northern Louisiana. We have a total of 50,000 net acres with Haynesville potential in East Texas and Louisiana.

In the Marcellus shale program in Pennsylvania, we drilled and completed our first horizontal well in McKean County, Pennsylvania during the third quarter. At quarter end, we were in the process of drilling and completing our second horizontal well, which is also in McKean County. We are moving ahead with the construction of a sales line for this portion of our acreage. We currently have over 40,000 net acres in north central Pennsylvania with potential for the Marcellus shale.

Shift toward oil-weighted projects. As a result of continued downward pressure on natural gas prices and an increase in oil prices, we began shifting capital investment dollars toward oil-weighted projects during the third quarter. We saw an increase in activity in our Permian and Rocky Mountain regions as a result of this shift in capital.

Borrowing base on credit facility maintained. On September 29, 2009, the borrowing base on our credit facility was redetermined and maintained by our bank group at a value of $900 million.

Marketing of non-core properties. In the third quarter of 2009, we began marketing a new package of certain non-core properties located primarily in the Rocky Mountain region. Please refer to Note 13 – Assets Held for Sale, in Part I, Item 1 of this report for additional information.

Production results. The table below details the regional breakdown of our third quarter 2009 production:

	Mid-Continent	ArkLaTex	Gulf Coast	Permian	Rocky Mountain	Total (1)
Third Quarter 2009 Production:						
Oil (MBbl)	65.4	29.4	90.5	414.3	928.1	1,527.7
Gas (MMcf)	8,483.2	3,420.5	1,495.6	1,023.8	2,787.9	17,211.0
Equivalent (MMCFE)	8,875.7	3,596.8	2,038.4	3,509.7	8,356.8	26,377.4
Avg. Daily Equivalents (MMCFE/d)	96.5	39.1	22.2	38.1	90.8	286.7
Relative percentage	34%	13%	8%	13%	32%	100%

(1) Totals may not add due to rounding

For the third quarter of 2009 our oil and gas production was in-line with our expectations and higher than our original budget estimates from the beginning of the year. Production has declined over the last three quarters as a result of lower levels of capital investment. Our ability to fund the capital investments necessary to grow our production is influenced significantly by the price we receive for produced oil and natural gas. Market prices for natural gas and oil during the first several months of the year limited the amount of capital available to invest. We also deferred some of our capital investments due to our view that drilling and completion costs would decrease throughout the year as a result of lower levels of industry activity. Our expectation is that the deferral will provide a better economic return.

Equity Compensation. On August 1, 2009, we granted awards of performance shares and restricted stock units pursuant to our long term incentive program to various employees of the Company eligible to participate in the LTIP. The fair value associated with this grant was $31.6 million. Please refer to Note 5 – Compensation Plans within Part I, Item 1 of this report for additional discussion.

First Nine Months 2009 Highlights

Impairments. We recognized significant non-cash impairments during the first nine months of 2009. We recorded $147.0 million of proved property impairments during the first quarter of 2009, and our total impairment of proved properties for the nine months ended September 30, 2009, totaled $153.2 million. A significant decrease in the market price for natural gas, including differentials in effect at March 31, 2009, caused the majority of the non-cash impairment of proved properties in that period. The largest portion of the impairment was $97.3 million related to assets located in the Mid-Continent region which were significantly impacted by wider than normal differentials at that time. During the second quarter of 2009, we incurred a $6.0 million impairment on proved properties related to the write-down of certain assets located in the Gulf of Mexico in which we are relinquishing our ownership interests.

During the first nine months of 2009, we recognized a charge of $20.3 million for the abandonment and impairment of unproved properties. The largest component of the abandonment and impairment of unproved properties was associated with our Floyd shale leasehold in Mississippi that was recognized during the second quarter of 2009.

Lastly, we incurred inventory write-downs of $13.4 million for the nine-month period ended September 30, 2009, as a result of the decrease in the market value of tubular goods and other inventory items that were purchased in 2008 when prices for these goods were considerably higher.

Net Profits Plan. For the nine months ended September 30, 2009, the change in the value of this liability resulted in a non-cash benefit of $14.0 million compared to non-cash expense of $46.9 million for the same period in 2008. Significant decreases in oil and gas commodity prices 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.

Payments made or accrued for current year distributions under the Net Profits Plan totaled $14.1 million and $45.9 million for the nine months ended September 30, 2009, and 2008, respectively. 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 liability amounts. More detailed discussion is included in the Comparison of Financial Results and Trends sections below and in Note 11 – Fair Value Measurements and Note 5 – Compensation Plans in Part I, Item 1. An increasing percentage of the costs associated with the payments from the Net Profits Plan are now being categorized as general and administrative expense as compared to exploration expense. This is a function of the normal departure of employees who previously contributed to our exploration efforts. In December 2007, our Board approved an incentive compensation plan restructuring, whereby the Net Profits Plan was replaced with a long-term incentive program utilizing equity awards. As a result, the 2007 Net Profits Plan pool was the last pool established.

The calculation of the estimated liability for the Net Profits Plan is highly sensitive to our price estimates and discount rate assumptions. For example, if we changed the commodity prices in our calculation by five percent, the liability recorded on the balance sheet at September 30, 2009, would differ by approximately $13 million. A one percentage point decrease in the discount rate would result in an increase to the liability of approximately $8 million, while a one percentage point increase in the discount rate would result in a decrease to the liability of approximately $7 million. We frequently re-evaluate the assumptions used in our calculations and consider the possible impacts stemming from the current market environment including current and future oil and gas prices, discount rates, and overall market conditions.

Production results. The table below details the regional breakdown of our first nine months of 2009 production:

	Mid-Continent	ArkLaTex	Gulf Coast	Permian	Rocky Mountain	Total (1)
First nine months of 2009 Production:						
Oil (MBbl)	213.3	103.0	288.2	1,419.4	2,792.0	4,815.8
Gas (MMcf)	26,247.5	11,231.0	5,156.4	3,093.7	8,326.9	54,055.5
Equivalent (MMCFE)	27,527.5	11,848.7	6,885.4	11,610.3	25,078.7	82,950.6
Avg. Daily Equivalents (MMCFE/d)	100.8	43.4	25.2	42.5	91.9	303.8
Relative percentage	34%	14%	8%	14%	30%	100 %

(1) Totals may not add due to rounding

For the first nine months of 2009 our production and oil and gas production revenues have outperformed our initial budget for 2009 due to stronger than anticipated production results from our Mid-Continent and Permian regions.

Outlook for the Remainder of 2009 and 2010

Unlike prior years, we entered 2009 without a specific capital budget for exploration and development activities. Our plan for 2009 was to make capital investments for exploration and development activities at a level at or near our operating cash flows. We established a flexible capital program that could be quickly adjusted rather than setting a fixed budget for the year. We have maintained our discipline and have kept our investing activities within operating cash flow throughout the year.

With respect to oil-weighted and liquids-weighted projects, we believe we are at the appropriate point in the commodity price cycle where increased levels of capital investment should be made. In recent months we have been increasing our activity in the oilier parts of our portfolio, specifically the Permian and Rocky Mountain regions. We currently anticipate that we will maintain or increase this level of oil-weighted activity through 2010. Generally, we do not believe that current natural gas prices support capital investment development projects at this time. We plan to continue to drill wells in certain exploratory projects that have the potential to add significant amounts of proved reserves and resource to our inventory. An example of this is our drilling in what appears to be the natural gas window in the Eagle Ford shale play. We also plan to drill some natural gas wells in order to preserve certain strategic acreage positions that would otherwise expire.

Financial Results of Operations and Additional Comparative Data

We recorded a net loss of $4.4 million or $0.07 per diluted share for the three months ended September 30, 2009, compared to third quarter 2008 results of net income of $87.0 million or $1.38 per diluted share.

The table below provides information regarding selected production and financial information for the quarter ended September 30, 2009, and the immediately preceding three quarters. Additional details of per MCFE costs are contained later in this section.

	For the Three Months Ended			
	September 30, 2009	June 30, 2009	March 31, 2009	December 31, 2008
	(In millions, except production sales data)			
Production (BCFE)	26.4	28.2	28.4	30.0
Oil and gas production revenue, excluding the effects of hedging	$ 152.7	$ 145.3	$ 130.4	$ 190.5
Realized oil and gas hedge gain	$ 28.3	$ 43.3	$ 55.6	$ 44.8
Gain (loss) on divestiture activity	$ (11.3)	$ 1.3	$ (0.6)	$ 9.5
Lease operating expense	$ 34.3	$ 35.6	$ 41.2	$ 47.7
Transportation costs	$ 5.3	$ 4.6	$ 5.5	$ 6.1
Production taxes	$ 9.0	$ 9.3	$ 9.1	$ 11.8
DD&A	$ 67.0	$ 70.4	$ 91.7	$ 95.1
Exploration	$ 15.7	$ 19.5	$ 13.6	$ 17.7
Impairment of proved properties	$ 0.1	$ 6.0	$ 147.0	$ 292.1
Abandonment and impairment of unproved properties	$ 4.8	$ 11.6	$ 3.9	$ 34.7
Impairment of materials inventory	$ 2.1	$ 2.7	$ 8.6	$ -
Impairment of goodwill	$ -	$ -	$ -	$ 9.5
General and administrative	$ 20.8	$ 18.2	$ 16.4	$ 12.4
Bad debt expense	$ -	$ -	$ -	$ -
Change in Net Profits Plan liability	$ 6.8	$ 2.4	$ (23.3)	$ (80.9)
Unrealized derivative (gain) loss	$ 4.1	$ 11.3	$ 1.8	$ (12.0)
Net income (loss)	$ (4.4)	$ (8.3)	$ (87.6)	$ (127.1)
Percentage change from previous quarter:				
Production (BCFE)	(6)%	(1)%	(5)%	8%
Oil and gas production revenue, excluding the effects of hedging	5%	11%	(32)%	(47)%

Realized oil and gas hedge gain	(35)%	(22)%	24%	(184)%
Gain (loss) on divestiture activity	(969)%	317%	(106)%	290%
Lease operating expense	(4)%	(14)%	(14)%	9%
Transportation costs	15%	(16)%	(10)%	(8)%
Production taxes	(3)%	2%	(23)%	(48)%
DD&A	(5)%	(23)%	(4)%	31%
Exploration	(19)%	43%	(23)%	65%
Impairment of proved properties	(98)%	(96)%	(50)%	N/M
Abandonment and impairment of unproved properties	(59)%	197%	(89)%	N/M
Impairment of materials inventory	(22)%	(69)%	N/A	N/A
Impairment of goodwill	N/A	N/A	(100)%	N/A
General and administrative	14%	11%	32%	(49)%
Bad debt expense	N/A	N/A	N/A	(100)%
Change in Net Profits Plan liability	183%	(110)%	(71)%	132%
Unrealized derivative (gain) loss	(64)%	528%	(115)%	173%
Net income (loss)	(47)%	(91)%	(31)%	(246)%

Changes in production volumes, oil and gas production revenues, and costs reflect the cyclical and highly volatile nature of our industry. As a result of the effects of lower commodity prices, we have seen reduced activity among many exploration and production companies over the past year which has led to lower lease operating costs over the last two quarters. We believe that industry activity may be stabilizing to a degree where these costs no longer have much room to decline further. Production taxes are largely dependent on the prices we receive for oil and natural gas. Depreciation, depletion, and amortization generally had been pressured upward in recent years as production related to properties acquired or developed in a higher cost environment became a larger percentage of our production mix. During the first nine months of 2009, we have seen our DD&A rate fluctuate as a result of swings in commodity prices that impact impairments and underlying proved reserve volumes. Additionally, the accounting treatment for assets that are classified as assets held for sale also impacts our DD&A rate. Our general and administrative expense will be impacted by cash payments made under the Net Profits Plan, which generally reflect our realized commodity prices.

A three-month 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
	2009	2008		2009	2008	
Net production volumes						
Oil (MBbl)	1,528	1,583	(3)%	4,816	4,895	(2)%
Natural gas (MMcf)	17,211	18,212	(5)%	54,055	55,238	(2)%
MMCFE (6:1)	26,377	27,707	(5)%	82,951	84,605	(2)%
Average daily production						
Oil (Bbl per day)	16,606	17,203	(3)%	17,640	17,863	(1)%
Natural gas (Mcf per day)	187,076	197,952	(5)%	198,005	201,599	(2)%
MCFE per day (6:1)	286,711	301,167	(5)%	303,848	308,778	(2)%
Oil & gas production revenues (1)						
Oil production revenue	$ 95,715	$ 131,840	(27)%	$ 261,614	$ 404,333	(35)%
Gas production revenue	85,267	173,177	(51)%	293,963	518,731	(43)%
Total	$ 180,982	$ 305,017	(41)%	$ 555,577	$ 923,064	(40)%
Oil & gas production expense						
Lease operating expense	$ 34,266	$ 43,624	(21)%	$ 111,117	$ 119,704	(7)%
Transportation costs	5,393	6,638	(19)%	15,420	16,139	(4)%
Production taxes	8,975	22,462	(60)%	27,391	69,982	(61)%
Total	$ 48,634	$ 72,724	(33)%	$ 153,928	$ 205,825	(25)%
Average realized sales price (1)						
Oil (per Bbl)	$ 62.65	$ 83.30	(25)%	$ 54.32	$ 82.61	(34)%
Natural gas (per Mcf)	$ 4.95	$ 9.51	(48)%	$ 5.44	$ 9.39	(42)%
Per MCFE Data:						

Average net realized price (1)	$ 6.86	$ 11.01	(38)%	$ 6.70	$ 10.91	(39)%
Lease operating expenses	(1.30)	(1.57)	(17)%	(1.34)	(1.41)	(5)%
Transportation costs	(0.20)	(0.24)	(17)%	(0.19)	(0.19)	-%
Production taxes	(0.34)	(0.81)	(58)%	(0.33)	(0.83)	(60)%
General and administrative	(0.79)	(0.87)	(9)%	(0.67)	(0.79)	(15)%
Operating profit	$ 4.23	$ 7.52	(44	$ 4.17	$ 7.69	(46)%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$ 2.54	$ 2.61	(3)%	$ 2.76	$ 2.59	7%

(1) Includes the effects of hedging activities

We present per MCFE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe require analysis. Volatility in commodity prices has impacted our operating margins. The decrease in our equivalent realized price for production has corresponded with the significant downward move in commodity prices over the last year, while our cost structure has improved over the past year, it has not moved to the same degree. Our operating margin of $4.23 per MCFE for the third quarter of 2009 decreased 44 percent from the $7.52 per MCFE we realized in the third quarter of 2008. However, it has decreased only one percent from the $4.29 per MCFE reported for the second quarter of this year.

We experienced a decline in our operating margins in the first nine months of 2009, compared with the same period in 2008, due primarily to a decrease in commodity prices. For the nine months ended

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September 30, 2009, our operating margin was $4.17 per MCFE compared to $7.69 per MCFE for the same period in 2008.

Average daily production for the first nine months of 2009 decreased slightly to 303.8 MMCFE compared with 308.8 MMCFE for the same period in 2008. For the nine months ended September 30, 2009, our average net realized price decreased $4.21 per MCFE to $6.70 per MCFE compared with the same period in 2008. Lower commodity prices were the principal driver of the decrease in the first nine months of 2009, compared with the same period in 2008. Unit costs decreased for the first nine months of 2009 as lease operating expense decreased $0.07 per MMCFE to $1.34 per MMCFE, production taxes decreased $0.50 per MCFE to $0.33 per MCFE and general and administrative expense decreased $0.12 per MCFE to $0.67 per MCFE. Production taxes are highly correlated to commodity prices, and a portion of our general and administrative expense is linked to our profitability and cash flow. Transportation costs remained steady at $0.19 per MCFE for the first nine months of 2009 and 2008.

For the nine months ended September 30, 2009, depletion, depreciation, amortization, and asset retirement obligation accretion expense, increased $0.17 per MCFE to $2.76 per MCFE compared with the same period in 2008. The depletion, depreciation, and amortization increase is a result of a decrease in proved reserves used to calculate DD&A in the first quarter of 2009 as described above. Exploration expense for the first nine months of 2009 was $48.8 million, which was 15 percent higher than the $42.4 million incurred during the first nine months of 2008. Geological and geophysical expense increased $11.8 million due to an increase in the amount spent for seismic analysis. This increase was offset by a $3.6 million decrease in exploration overhead due to a decrease in Net Profits Plan payments resulting from decreased oil and gas commodity prices and a $1.8 million decrease in exploratory dry hole expense.

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

Financial Information (In thousands, except per share amounts):					
	September 30, 2009		December 31, 2008		Percent Change Between Periods
Working capital (deficit)	$	(68,880)	$	15,193	(553)%
Long-term debt	$	499,784	$	558,713	(11)%
Stockholders’ equity	$	996,117	$	1,162,509	(14)%

	For the Three Months Ended September 30, 2009	2008	Percent Change Between Periods	For the Nine Months Ended September 30, 2009	2008	Percent Change Between Periods
Basic net income (loss) per common share	$ (0.07)	$ 1.40	(105)%	$ (1.61)	$ 3.44	(147)%
Diluted net income (loss) per common share	$ (0.07)	$ 1.38	(105)%	$ (1.61)	$ 3.39	(147)%
Basic weighted-average common shares	62,505	62,187	1%	62,420	62,254	-%

outstanding						
Diluted weighted-average common shares outstanding	62,505	63,078	(1)%	62,420	63,327	(1)%

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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 our 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. We have in-the-money stock options, unvested RSUs, and PSAs that may be potentially dilutive securities. Both basic and diluted earnings per share are presented in the table above. There were no potentially dilutive shares related to in-the-money stock options, unvested RSUs, and PSAs included in the diluted earnings per share calculation for the three months or nine months ended September 30, 2009, as we recorded a net loss for each of those periods. 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 September 30, 2009, and 2008, earnings per share calculations reflect our stock repurchases, offset by increases in outstanding shares related to stock option exercises, ESPP shares issued, and the settlement of vested RSUs. We issued 33,014 and 860,330 shares of common stock during the nine-month periods ended September 30, 2009, and 2008, respectively, as a result of stock option exercises. Shares issued in the first nine months of 2008 were offset by the repurchase of 2,135,600 shares of common stock during the first quarter of 2008 through our stock repurchase plan. There were no shares repurchased during the first nine months of 2009. Additionally, the number of RSUs that vested during the first nine months of 2009 and 2008 were 122,569 and 200,899, respectively.

Additional Comparative Data in Tabular Form:

	Change Between the Three Months Ended September 30, 2009, and 2008	Change Between the Nine Months Ended September 30, 2009, and 2008
Decrease in oil and gas production revenues, net of hedging (In thousands)	$ (124,035)	$ (367,487)

Components of revenue increases (decreases):

Oil		
Realized price change per Bbl, including the effects of hedging	$ (20.65)	$ (28.29)
Realized price percentage change	(25)%	(34)%
Production change (MBbl)	(55)	(79)
Production percentage change	(3)%	(2)%
Natural Gas		
Realized price change per Mcf, including the effects of hedging	$ (4.56)	$ (3.95)
Realized price percentage change	(48)%	(42)%
Production change (MMcf)	(1,001)	(1,183)
Production percentage change	(5)%	(2)%

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	2009	2008	2009	2008
Oil	53%	43%	47%	44%
Natural gas	47%	57%	53%	56%
Production				
Oil	35%	34%	35%	35%
Natural gas	65%	66%	65%	65%

Information regarding the components of exploration expense:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Summary of Exploration Expense		(In millions)		
Geological and geophysical expenses	$ 6.2	$ 2.0	$ 16.9	$ 5.1
Exploratory dry hole expense	0.1	-	4.8	6.6
Overhead and other expenses	9.4	8.7	27.1	30.7
Total	$ 15.7	$ 10.7	$ 48.8	$ 42.4

Information regarding the effects of oil and gas hedging activity:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Oil Hedging				
Percentage of oil production hedged	59%	66%	51%	62%
Oil volumes hedged (MBbl)	894	1,040	2,463	3,037
Increase (decrease) in oil revenue	$ 1.1 million	$ (45.4 million)	$ 21.6 million	$ (124.5 million)
Average realized oil price per Bbl before hedging	$ 61.93	$ 111.97	$ 49.82	$ 108.04
Average realized oil price per Bbl after hedging	$ 62.65	$ 83.30	$ 54.32	$ 82.61
Natural Gas Hedging				
Percentage of gas production hedged	43%	50%	47%	44%
Natural gas volumes hedged (MMBtu)	$ 7.8 million	$ 9.7 million	$ 26.8 million	$ 25.8 million

Increase (decrease) in gas revenue	$	27.2 million	$	(8.1 million)	$	105.6 million	$	(21.3 million)
Average realized gas price per Mcf before hedging	$	3.37	$	9.96	$	3.49	$	9.78
Average realized gas price per Mcf after hedging	$	4.95	$	9.51	$	5.44	$	9.39

Comparison of Financial Results and Trends between the three months ended September 30, 2009, and 2008

Oil and gas production revenue. Average daily production decreased five percent to 286.7 MMCFE for the quarter ended September 30, 2009, compared with 301.2 MMCFE for the quarter ended September 30, 2008. The following table presents the regional changes in our production and oil and gas revenues and costs between the two quarters.

	Average Net Daily Production Added (Lost) (MMCFE)	Pre-Hedge Oil and Gas Revenues Lost (In millions)	Production Costs Decrease (In millions)
Mid-Continent	6.8	$ (49.5)	$ (5.3)
ArkLaTex	(11.4)	(38.1)	(0.7)
Gulf Coast	(11.2)	(28.1)	(4.1)
Permian	3.1	(27.3)	(3.0)
Rocky Mountain	(1.8)	(62.9)	(11.0)
Total	(14.5)	$ (205.9)	$ (24.1)

Production decreased between these two periods as a result of decreased levels of capital investment throughout 2009 and properties that were sold in the second half of 2008. The largest regional increase between the third quarters of 2009 and 2008 occurred in the Mid-Continent region as a result of success in the horizontal Woodford shale program in the Arkoma Basin and strong results from our Deep Springer program in the Anadarko Basin. The production growth in the Permian region is the result of continued development of the Wolfberry assets at Sweetie Peck and Halff East. These increases are offset by a decrease in the ArkLaTex due to natural decline and decreased levels of capital investment in the region by us and our partners, particularly at the Elm Grove Field. The decrease in the Gulf Coast region's production is primarily a result of the loss of production contribution from the Judge Digby Field due to an exchange of assets that occurred in late 2008. The Rocky Mountain region realized a slight decline as a result of its more mature production decline profile and modest capital investment.

The following table summarizes the average realized prices we received in the third quarter of 2009 and 2008, before the effects of hedging. Prices for oil and gas decreased significantly between the two periods.

	For the Three Months Ended September 30, 2009	2008
Realized oil price ($/Bbl)	$ 61.93	$ 111.97
Realized gas price ($/Mcf)	$ 3.37	$ 9.96
Realized equivalent price ($/MCFE)	$ 5.79	$ 12.94

The combination of relatively consistent production volumes and lower commodity prices between periods resulted in lower oil and gas revenue.

Realized oil and gas hedge gain (loss). We recorded a realized hedge gain of $28.3 million for the three-month period ended September 30, 2009, the majority of which related to favorable settlements on gas hedges, compared with a $53.5 million loss for the same period in 2008, which was primarily due to unfavorable settlements on our oil hedges. Please refer to our discussion above under the heading Oil and Gas Prices.

Gain (loss) on divestiture activity. We had an $11.3 million net loss on divestiture activity for the three-month period ended September 30, 2009, compared with a $5.0 million net loss on divestiture activity

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for the comparable period of 2008. In the third quarter of 2009, we reclassified a portion of assets previously classified as held for sale to assets held and used, as these assets were no longer being actively marketed. In accordance with ASC Topic 360, we measured the assets at the lower of the assets' carrying amount before the assets were classified as held for sale, adjusted for any depreciation and depletion expense that would have been recognized had the assets been continuously classified as held and used, or the assets fair value at the date of the subsequent decision not to sell was made. As a result of this measurement we recognized a $9.8 million loss on unsuccessful sale of properties. The $5.0 million loss on divestiture activity for the three-month period ended September 30, 2008, was due to adjustments relating to the divestiture of non-core oil and gas properties to Abraxas that occurred in the first quarter of 2008.

Marketed gas system revenue and expense. Marketed gas system revenue, which is included in the line item marketed gas system and other operating revenue, decreased $10.3 million to $13.9 million for the quarter ended September 30, 2009, compared with $24.2 million for the comparable period of 2008. Concurrent with the decrease in marketed gas system revenue, marketed gas system expense decreased $8.6 million to $14.4 million for the quarter ended September 30, 2009, compared with $23.0 million for the comparable period of 2008. We expect that marketed gas system revenue and expense will continue to trend with increases and decreases in production and our net realized price.

Oil and gas production expense. Total production costs decreased $24.1 million, or 33 percent, to $48.6 million for the third quarter of 2009 from $72.7 million in the comparable period of 2008. Total oil and gas production costs per MCFE decreased $0.78 to $1.84 for the third quarter of 2009, compared with $2.62 for the same period in 2008. This decrease is comprised of the following:

- A $0.47 decrease in production taxes on a per MCFE basis due to the decrease in realized prices between periods. We expect production taxes to trend with commodity prices.

- A $0.32 decrease in recurring LOE on a per MCFE basis due to reductions in recurring LOE that stem from the slowdown in activity in the exploration and production industry, as well as the broader economy

- A $0.04 decrease in overall transportation costs on a per MCFE basis driven by a decrease in transportation costs on our properties located in the Rocky Mountain region

- A $0.05 increase in overall workover LOE on a per MCFE basis relating to an increase in workover activity in the Rocky Mountain region.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A decreased $5.4 million or seven percent to $67.0 million for the three-month period ended September 30, 2009, compared with $72.4 million for the same period in 2008. DD&A expense per MCFE decreased three percent to $2.54 for the three-month period ended September 30, 2009, compared to $2.61 for the same period in 2008. Our DD&A expense per MCFE decreased due to the significant decrease in the carrying value of our properties as a result of proved property impairments that we incurred in the fourth quarter of 2008 and the first quarter of 2009.

Exploration. Exploration expense increased 47 percent to $15.7 million for the three-month period ended September 30, 2009, compared with $10.7 million for the same period in 2008. Geological and geophysical expense increased $4.2 million due to an increase in the amount spent for seismic analysis. We anticipate that we will continue to spend money on seismic analysis in the fourth quarter and potentially into 2010 in order to minimize risk with respect to the acreage in our emerging resource plays and optimize their future development. Exploration overhead increased $700,000 due to an increase in Net Profits Plan payments as a result of increased oil and gas commodity prices from the second quarter of 2009. We expect payments made under the Net Profits Plan to trend with commodity prices.

General and administrative. General and administrative expense decreased $3.3 million or 14 percent to $20.8 million for the quarter ended September 30, 2009, compared with $24.1 million for the comparable period of 2008. G&A expense per MCFE decreased $0.08 to $0.79 per MCFE for the third quarter of 2009 compared to $0.87 per MCFE for the same period in 2008. The majority of the decrease was as a result of a $4.1 million reduction in payments made under the Net Profits Plan for the quarter ended September 30, 2009, compared with the same period in 2008. The decrease was primarily the result of lower commodity prices, which resulted in smaller Net Profits Plan payments to plan participants. As of the end of the third quarter of 2009, 17 of our 21 pools are in payout status. No additional pools are expected to reach payout in 2009. We expect payments made under the Net Profits Plan to trend with commodity prices.

Bad debt expense. We did not record any bad debt expense for the quarter ended September 30, 2009. For the quarter ended September 30, 2008, we recorded $6.7 million of bad debt expense as a result of the filing for bankruptcy protection by SemGroup, affiliates of which purchased a portion of our crude oil production. This amount related to July 2008 oil production that was reserved for in the three-month period ended September 30, 2008. We currently anticipate that we will recover a portion of the previously written off amount during the fourth quarter of 2009.

Change in Net Profits Plan liability. For the quarter ended September 30, 2009, this non-cash expense was $6.8 million compared to a benefit of $34.9 million for the same period in 2008. The increase in oil and gas commodity prices in 2009 has increased the estimated liability for the future amounts to be paid to plan participants. In the third quarter of 2008 oil and gas commodity prices began to decline, which resulted in the reduction of our estimated liability for future cash payments. 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. We expect the change in this liability to trend with commodity prices.

Unrealized derivative (gain) loss. We recognized a loss of $4.1 million in the third quarter of 2009 compared to a gain of $4.4 million in the third quarter of 2008. This non-cash item is driven by the change in the value of our hedge position, as well as the portion of that position that is considered ineffective for accounting purposes. Please refer to our discussion above under the heading Oil and Gas Prices.

Other expense. Other expense decreased $6.8 million to $968,000 for the quarter ended September 30, 2009, compared with $7.8 for the same period in 2008. In the third quarter of 2009, we incurred an additional loss related to hurricanes of $1.2 million, which was a result of a decrease in our estimate of insurance reimbursements, compared with a loss related to hurricanes of $7.0 million for the same period in 2008. Both losses primarily relate to the Vermillion 281 platform that was lost in Hurricane Ike.

Income tax expense. We recorded a benefit from income tax of $2.6 million for the third quarter of 2009 compared to income tax expense of $50.5 million for the third quarter of 2008 resulting in effective tax rates of 37.1 percent and 36.7 percent, respectively. The change in income tax expense is primarily the result of the changes to components of net income as discussed above. Our effective tax rate reflects changes in the effects of other permanent differences which include the domestic production activities deduction, percentage depletion, the impacts of net operating loss carrybacks, and to a lesser extent, changes in the mix of the highest marginal state tax rates as a result of acquisition and drilling activity. The effects of individual components can vary between periods resulting in fluctuations in our tax rate. Our cash tax expense decreased for the third quarter of 2009 compared to the same period of 2008 due to decreased taxable income estimates caused by reduced revenue resulting from decreased commodity prices and the impact of our drilling activity during 2009. However, with rising commodity prices and delayed drilling activity this trend may not continue into the fourth quarter even though we will receive a $5.0 million refund related to our 2008 federal tax return. If the U.S Congress passes legislation to reduce or eliminate current tax deductions for intangible drilling costs, the domestic production activities deduction, or

percentage depletion, we would expect our effective tax rate and the cash tax portion of our income tax expense to increase.

Comparison of Financial Results and Trends between the nine months ended September 30, 2009, and 2008

Oil and gas production revenue. Average daily production decreased two percent to 303.8 MMCFE for the nine months ended September 30, 2009, compared with 308.8 MMCFE for the same period in 2008. The following table presents the regional changes in our production and oil and gas revenues and costs between the two nine month periods:

	Average Net Daily Production Added (Lost)	Pre-Hedge Oil and Gas Revenues Lost	Production Costs Increase (Decrease)
	(MMCFE)	(In millions)	(In millions)
Mid-Continent	12.6	$ (140.9)	$ (13.3)
ArkLaTex	(5.6)	(98.1)	0.5
Gulf Coast	(15.7)	(96.0)	(11.6)
Permian	6.2	(85.0)	(2.9)
Rocky Mountain	(2.5)	(220.6)	(24.6)
Total	(5.0)	$ (640.6)	$ (51.9)

The largest regional increase between the nine months ended September 30, 2009, and 2008, occurred in the Mid-Continent and Permian regions and was partially offset by decreases in the Gulf Coast and ArkLaTex regions which are described in more detail in the quarterly comparison of financial results and trends discussion above.

The following table summarizes the average realized prices we received in the first nine months of 2009 and 2008, before the effects of hedging. Prices for oil and gas decreased significantly between the two periods:

	For the Nine Months Ended September 30,	
	2009	2008
Realized oil price ($/Bbl)	$ 49.82	$ 108.04
Realized gas price ($/Mcf)	$ 3.49	$ 9.78
Realized equivalent price ($/MCFE)	$ 5.16	$ 12.63

The combination of a decrease in production volumes and lower commodity prices between periods resulted in lower oil and gas revenue.

Realized oil and gas hedge gain (loss). We recorded a realized hedge gain of $127.2 million for the nine-month period ended September 30, 2009, related to favorable settlements on oil and gas hedges, compared with a $145.8 million loss for the same period in 2008, which was primarily due to unfavorable settlements on our oil hedges.

Gain (loss) on divestiture activity. We recorded a $10.6 million net loss on divestiture activity for the nine-month period ended September 30, 2009, resulting primarily from the accounting treatment of certain assets that were held for sale and were then subsequently reclassified as held and used. We recorded a $54.1 million net gain on divestiture activity for the comparable period of 2008 due to the divestiture of non-core oil and gas properties to Abraxas that occurred in the first quarter of 2008. We regularly evaluate potential divestitures of non-strategic properties.

Marketed gas system revenue and expense. Marketed gas system revenue, which is included in the line item marketed gas system and other operating revenue, decreased $23.9 million to $41.5 million for the nine-month period ended September 30, 2009, compared with $65.4 million for the comparable period of 2008. Concurrent with the decrease in marketed gas system revenue, marketed gas system expense decreased $19.5 million to $41.4 million for the nine-month period ended September 30, 2009, compared with $60.9 million for the comparable period of 2008. We expect that marketed gas system revenue and expense will continue to trend with increases and decreases in production and our net realized price.

Oil and gas production expense. Total production costs decreased $51.9 million, or 25 percent, to $153.9 million for the first nine months of 2009 from $205.8 million in the comparable period of 2008. Total oil and gas production costs per MCFE decreased $0.57 to $1.86 for the first nine months of 2009, compared with $2.43 for the same period in 2008. This decrease is comprised of the following:

- A $0.50 decrease in production taxes on a per MCFE basis due to the decrease in realized prices between periods, particularly in the oil-weighted Rocky Mountain and Permian Basin regions

- A $0.07 decrease in recurring LOE on a per MCFE basis due to reductions in recurring LOE that stem from the slowdown in activity in the exploration and production industry, as well as the broader economy, which was offset by generally higher costs in the first quarter of 2009 and in the oil-weighted Permian region for items such as fuel and fluid disposal

- Transportation costs and workover LOE on a per MCFE basis remained flat.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A increased $10.0 million or five percent to $229.1 million for the nine-month period ended September 30, 2009, compared with $219.1 million for the same period in 2008. DD&A expense per MCFE increased seven percent to $2.76 for the nine-month period ended September 30, 2009, compared to $2.59 for the same period in 2008. The DD&A increase reflects the industry trend of increased amounts of investment to add reserves. Generally, as these recently acquired or developed assets become a larger portion of our asset base, our DD&A expense will increase as those acquisitions and developments were made at higher costs. Additionally, the reserves used in the calculation of DD&A expense are impacted by price.

Exploration. Exploration expense increased 15 percent to $48.8 million for the nine-month period ended September 30, 2009, compared with $42.4 million for the same period in 2008. Geological and geophysical expense increased $11.8 million due to an increase in the amount spent for seismic analysis. This increase was offset by a $1.8 million decrease in exploratory dry hole expense, as well as a $3.6 million decrease in exploration overhead due to a decrease in Net Profits Plan payments as a result of decreased oil and gas commodity prices.

Impairment of proved properties. Impairment of proved properties increased 141 percent to $153.2 million for the nine-month period ended September 30, 2009, compared with $10.1 million for the same period in 2008. This impairment was driven by a significant decrease in realized gas prices in the first quarter of 2009, particularly in the Mid-Continent region, and for our coalbed methane project at Hanging Woman Basin. During the second quarter of 2009, we incurred an additional impairment on proved properties of $6.0 million related to the write-down of certain assets located in the Gulf of Mexico in which we are relinquishing our ownership interests.

Abandonment and impairment of unproved properties. Abandonment and impairment of unproved properties increased $16.0 million to $20.3 million for the nine-month period ended September 30, 2009, compared with $4.3 million for the same period in 2008. The largest component of the increase relates to a write-off of Floyd shale acreage located in Mississippi that was recognized in the second quarter of 2009.

Impairment of materials inventory. We recorded a $13.4 million impairment of materials inventory for the nine-month period ended September 30, 2009. There were no impairments recorded for the nine-month period ended September 30, 2008. The inventory impairment was caused by a decrease in the value of tubular goods and other raw materials.

General and administrative. General and administrative expense decreased $11.8 million or 18 percent to $55.3 million for the nine months ended September 30, 2009, compared with $67.1 million for the comparable period of 2008. G&A expense per MCFE decreased $0.12 to $0.67 per MCFE for the first nine months of 2009 compared to $0.79 per MCFE for the same period in 2008. The decrease was a result of a $14.2 million reduction in payments made under the Net Profits Plan for the nine months ended September 30, 2009, compared with the same period in 2008. The decrease was primarily the result of lower commodity prices. Additionally, G&A expense decreased $5.8 million as a result of an increase in COPAS overhead reimbursements for the nine months ended September 30, 2009, compared with the same period in 2008, which is due to an increase in our operated well count.

These decreases were partially offset by an increase in base employee compensation, cash bonus, and long-term incentive compensation totaling approximately $9.8 million for the nine months ended 2009, compared with the same period of 2008. These increases are a result of an increase in employee head count between the two periods and current company performance.

Bad debt expense. We did not record any bad debt expense for the nine months ended September 30, 2009. We recorded $16.6 million of bad debt expense for the nine months ended September 30, 2008, as a result of the filing for bankruptcy protection by SemGroup, affiliates of which purchased a portion of our crude oil production. This amount related to oil produced in June and July of 2008 that was reserved in the nine-month period ended September 30, 2008. We currently anticipate that we will recover a portion of the previously written off amount during the fourth quarter of 2009.

Change in Net Profits Plan liability. For the nine months ended September 30, 2009, this non-cash item was a benefit of $14.0 million compared to an expense of $46.9 million for the same period in 2008. Decreases in oil and gas commodity prices have decreased the estimated liability for the future amounts to be paid to plan participants.

Unrealized derivative loss. We recognized a loss of $17.3 million for the nine months ended September 30, 2009, compared to a loss of $802,000 for the same period in 2008. This non-cash item is driven by the change in the value of our hedge position, as well as the portion of that position that is considered ineffective for accounting purposes.

Other expense. Other expense increased $3.2 million to $12.4 million for the nine months ended September 30, 2009, compared with $9.2 million for the same period in 2008. During the first nine months of 2009, we incurred $1.5 million of expense related to the assignment of a drilling rig contract in our Rocky Mountain region. We also incurred loss related to hurricanes of $8.3 million for the nine months ended September 30, 2009, compared with a loss related to hurricanes of 7.0 million for the same period in 2008.

Income tax expense. Income tax benefit totaled $61.6 million for the nine-month period of 2009 compared to a tax expense of $125.0 million for the same period of 2008 resulting in an effective tax rate of 38.0 percent and 36.8 percent, respectively. The change in income tax expense is primarily the result of changes to components of net income as discussed above. The 2009 increase in effective tax rate from 2008 reflects changes in tax benefit from other permanent differences including the domestic production activities deduction, percentage depletion, the impacts of net operating loss carrybacks, and to a lesser extent, changes in the mix of the highest marginal state tax rates as a result of acquisition and drilling expected in 2009 versus 2008. Our cash tax expense decreased for the nine months ended September 30, 2009, compared to the same period in 2008 due to an $11.0 million refund of taxes paid in 2008 that was received in the first quarter of 2009 and decreased taxable income estimates in 2009 caused

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by reduced revenue resulting from decreased commodity prices and the impact of our 2009 capital expenditures program.

Overview of Liquidity and Capital Resources

We believe that we have sufficient liquidity and capital resources to execute our business plans for the foreseeable future.

Sources of Cash

Based on our current outlook, we plan to keep capital expenditures for our exploration and development activities at a level at or near our operating cash flows in 2009. Accordingly, we do not expect to access the capital markets for the remainder of 2009. We anticipate that we will continue to evaluate our property base for divestiture candidates that we consider non-core to our strategic goals. We presently are marketing non-core assets and have identified assets that we intend to market for sale in the fourth quarter of 2009 depending on acquisition and divestiture market conditions. However, given our strong financial position we will not sell these properties unless we receive value we consider appropriate.

Our primary sources of liquidity are the cash flows provided by operating activities, use of our credit facility, sales of non-core properties, and access to capital markets. All of these sources can be impacted by the general condition of the broad economy and by significant fluctuations in oil and gas prices, operating costs, and volumes produced which affect us and our industry. 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. The borrowing base of our credit facility could be reduced as a result of lower commodity prices or sales of non-core producing properties. Historically, decreases in market prices have limited our industry's access to the capital markets. We believe the public debt markets are currently accessible. Equity and convertible debt issuances are also available to us as alternative financing sources. We do not anticipate the need to raise public debt or equity financing in the near term, however these are options we would consider under the appropriate circumstances. We intend to rely on our credit facility for borrowings.

Current Credit Facility

On April 14, 2009, we entered into an amended $1.0 billion senior secured revolving credit facility with twelve participating banks. The initial borrowing base was set at $900 million. On September 29, 2009, the lending group redetermined our reserve-backed borrowing base under the credit facility at $900 million. We have been provided a $678 million commitment amount by the bank group. The new amended credit facility agreement has a maturity date of July 31, 2012. Management believes that the current commitment is sufficient for our liquidity needs. To date, we have experienced no issues drawing upon our credit facility. No individual bank participating in the credit facility represents more than 16 percent of the lending commitments under the credit facility. We monitor the credit environment closely and have frequent discussions with the lending group.

As of October 27, 2009, we had $462.4 million of available borrowing capacity under this facility. Interest and commitment fees are accrued based on the borrowing base utilization grid located in Note 7 – Long-term Debt in Part I, Item 1 of this report. We have a single letter of credit outstanding under our credit facility in the amount of $569,000 as of October 27, 2009, which reduces the amount available under the commitment amount on a dollar-for-dollar basis. Borrowings under the facility are secured by mortgages on the majority of our oil and gas properties.

Our weighted-average interest rate in the three-month periods ended September 30, 2009, and 2008, was 5.9 percent and 5.7 percent, respectively. Our weighted-average interest rate in the nine-month periods ended September

30, 2009, and 2008, was 5.2 percent and 5.8 percent, respectively. Our weighted-average

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interest rates in the current and prior year include fees paid on the unused portion of the credit facility's aggregate commitment amount and amortization of the debt discount and deferred financing costs.

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 not more 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, 2009, our debt to EBITDA ratio and current ratio as defined by our credit agreement, were 1.16 and 2.59, respectively. We are in compliance with all financial and non-financial covenants under our credit facility.

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 2009 we spent $292.5 million for exploration and development capital expenditures. These amounts differ from our cost incurred amounts based on the timing of cash payments associated with these activities as compared to the accrual based activity upon which cost incurred amounts are presented. These cash flows were funded using cash inflows from operations and available borrowing capacity under our revolving credit facility.

Expenditures for exploration and development of oil and gas properties and acquisitions are the primary use of our capital resources. We expect our capital and exploration expenditures in 2009 will be at or near operating cash flows. The amount and allocation of future capital expenditures will depend upon a number of factors including the number and size of available economic acquisitions and drilling opportunities, our cash flows from operating and financing activities, and our ability to assimilate acquisitions. Also, the impact of oil and gas prices on investment opportunities, the availability of capital and borrowing facilities, and the success of our development and exploratory activities could lead to changes in funding requirements for future development. We regularly review our planned capital expenditures 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. There have been no share repurchases to date in 2009.

During the fourth quarter of 2009, the U.S. Congress plans to give consideration to a 2010 budget. Current proposals to fund proposed programs include eliminating or reducing current tax deductions for intangible drilling costs, the domestic production activities deduction, and percentage depletion. Legislation modifying or eliminating these deductions would have the immediate effect of reducing operating cash flows thereby reducing funding available for our exploration and development capital programs and those of our peers in the industry. These funding reductions could potentially have a significant adverse effect on drilling in the United States for a number of years.

The following table presents amount and percentage changes in cash flows between the nine-month periods ended September 30, 2009, and 2008. 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, 2009	For the Nine Months Ended September 30, 2008	Change	Percent Change
	(In thousands)			
Net cash provided by operating activities	$ 353,052	$ 568,764	$ (215,712)	(38)%
Net cash used in investing activities	$ 260,651	$ 433,208	$ (172,557)	(40)%
Net cash used in financing activities	$ 78,015	$ 173,670	$ (95,655)	(55)%

Analysis of Cash Flow Changes Between the Nine Months Ended September 30, 2009, and September 30, 2008

Operating activities. Cash received from oil and gas production revenue, net of the realized effects of hedging, decreased $365.6 million to $572.0 million for the first nine months of 2009, compared with $937.6 million for the same period in 2008. Included in operating revenues for the nine-month period ended September 30, 2009, is $127.2 million of net realized hedging gains. A significant portion of the decrease in oil and gas production revenue, net of the realized effects of hedging, was the result of decreases in commodity prices. We received a net cash refund for income taxes in the first nine months of 2009 of $10.1 million compared with net cash income taxes paid of $18.9 million for the same period in 2008.

Investing activities. Cash used for investing activities decreased $172.6 million for the nine months ended September 30, 2009, compared with the same period in 2008. Cash outflows for capital expenditures decreased $202.7 million or 41 percent to $292.5 million for the nine months ended September 30, 2009, reflecting a reduced level of activity as a result of lower commodity prices. Proceeds from an insurance settlement relating to Hurricane Ike were $15.3 million for the nine months ended September 30, 2009, compared with the same period in 2008 when we received no proceeds from insurance settlements. Cash outflow relating to the acquisition of oil and gas properties also decreased $83.4 million to $58,000 for the nine months ended September 30, 2009, compared with the same period in 2008 due to reduced activity in acquisition markets during the first nine months of 2009. We acquired assets in the Carthage Field during the first nine months of 2008, which have potential in the Cotton Valley and Haynesville shale formations. These decreases in cash flow were partially offset by a decrease year over year in proceeds from the sale of oil and gas properties. For the nine months ended September 30, 2009, we received $1.1 million from the sale of non-core properties compared with the same period in 2008 when we received $155.2 million, the majority of which was from the sale of non-core properties to Abraxas.

Financing activities. Net repayments on our credit facility decreased by $50.0 million for the nine-month period ended September 30, 2009, compared with the same period in 2008. We spent $11.1 million on debt issuance costs for the Company's amended credit facility during the nine-month period ended September 30, 2009. We did not incur any debt issuance costs during the nine-month period ended September 30, 2008. We spent $77.2 million to repurchase our common stock during the nine-month period ended September 30, 2008. There were no share repurchases during the same period in 2009.

Capital Expenditures

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,	
	2009	2008
	(In thousands)	
Development costs	$ 154,978	$ 456,798
Exploration costs	91,549	73,232
Acquisitions		
Proved properties	55	41,393
Unproved properties – acquisitions of proved properties (1)	-	42,389
Unproved properties - other	20,642	20,154
Total, including asset retirement obligations (2) (3)	$ 267,224	$ 633,966

(1) Represents a portion of the allocated purchase price of unproved properties acquired as part of the acquisition of proved properties.
(2) Includes capitalized interest of $1.4 million in 2009 and $3.5 million in 2008.
(3) Includes amounts relating to estimated asset retirement obligations of $672,000 in 2009 and $8.8 million in 2008.

Costs incurred for capital and exploration activities during the first nine months of 2009 decreased $366.7 million or 58 percent compared to the same period in 2008. Excluding acquisitions, our development and exploration investments decreased $283.5 million or 53 percent compared to the same period in the prior year. This decrease in capital and exploration activities during the first nine months of 2009 compared with the same period in 2008 is a result of our decision to invest at or near our operating cash flows for 2009 and to defer some development projects in order to improve returns on invested capital by taking advantage of expected improved commodity prices and/or lower drilling and completion costs. We currently expect to incur capital expenditures at a higher rate in the fourth quarter compared to the previous three quarters.

We believe our operating cash flows together with the cash available under our credit facility will be sufficient to fund our planned operating, drilling, and acquisition expenditures for some time. 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 gas commodity prices and changes in interest rates as discussed below under the caption Summary of Interest Rate Risk. Changes in interest rates can affect the amount of interest we earn on our cash, cash equivalents, 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

3.50% Senior Convertible Notes, but do affect their fair market value.

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 for the year ended December 31, 2008.

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. Please refer to Note 8 – Derivative Financial Instruments in Part I, Item 1 of this report for additional information regarding accounting for our derivative transactions.

Our net realized oil and gas prices are impacted by hedges we have placed on future forecasted production. Hedging is an important part of our financial risk management program. The amount of production we hedge is driven by the amount of debt on our consolidated balance sheet and the level of capital and long-term commitments we have made. In the case of a significant acquisition of producing properties, we will consider hedging a portion of the anticipated production in order to protect the economics assumed at the time of the acquisition. As of September 30, 2009, our hedged positions of anticipated production through the third quarter of 2012 totaled approximately 7 million Bbls of oil, 45 million MMBtu of natural gas, and 230,000 Bbls of natural gas liquids. As of October 27, 2009, we have hedge contracts in place through the third quarter of 2012 for a total of approximately 7 million Bbls of anticipated crude oil production, 57 million MMBtu of anticipated natural gas production, and 946,000 Bbls of anticipated natural gas liquids production.

In a typical commodity swap agreement, if the agreed upon published third-party index price is lower than the swap fixed price, we receive the difference between the index price and the agreed upon swap fixed price. If the index price is higher than the swap fixed price, we pay the difference. For collar agreements, we receive the difference between an agreed upon index and the floor price if the index price is below the floor price. We pay the difference between the agreed upon contracted ceiling price and the index price if the index price is above the contracted ceiling price. No amounts are paid or received if the index price is between the contracted floor and ceiling prices.

The following tables describe the volumes, average contract prices, and fair values of contracts we have in place as of September 30, 2009, and October 27, 2009. The Company seeks to minimize ineffectiveness by entering into oil derivative contracts indexed to NYMEX WTI and natural gas derivative contracts indexed to regional index prices associated with pipelines in proximity to the Company’s areas of production. As the Company’s derivative contracts contain the same index as the Company’s sales contracts, this results in derivative contracts that are highly correlated with the underlying hedged item.

Oil Contracts

Oil Swaps			
Contract Period	NYMEX WTI Volumes (Bbls)	Weighted-Average Contract Price (per Bbl)	Fair Value at September 30, 2009 Asset/(Liability) (In thousands)
Fourth quarter 2009	459,000	$ 72.31	$ 570
2010	1,596,000	$ 68.77	(8,418)
2011	1,164,000	$ 67.06	(11,222)
2012	566,300	$ 78.95	(46)
All oil swaps	3,785,300		$ (19,116)

Oil Collars				
Contract Period	NYMEX WTI Volumes (Bbls)	Weighted-Average Floor Price (per Bbl)	Weighted-Average Ceiling Price (per Bbl)	Fair Value at September 30, 2009 (Liability) (In thousands)
Fourth quarter 2009	384,500	$ 50.00	$ 67.31	$ (2,371)
2010	1,367,500	$ 50.00	$ 64.91	(17,859)
2011	1,236,000	$ 50.00	$ 63.70	(20,599)
All oil collars	2,988,000			$ (40,829)

Gas Contracts

Gas Swaps			
Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at September 30, 2009 Asset/(Liability)
	(MMBtu)	(per MMBtu)	(In thousands)
Fourth quarter 2009			
IF ANR OK	90,000	$ 7.43	$ 260
IF CIG	150,000	$ 7.42	453
IF EL PASO	300,000	$ 7.01	763
IF HSC	2,620,000	$ 8.60	10,416
IF NGPL	90,000	$ 7.14	235
IF RELIANT	810,000	$ 4.34	(123)
NYMEX Henry Hub	710,000	$ 7.18	1,713
2010			
IF ANR OK	60,000	$ 7.98	134
IF EL PASO	1,090,000	$ 6.79	1,017
IF HSC	6,080,000	$ 8.40	14,923
IF NGPL	990,000	$ 5.51	(425)
IF RELIANT	4,200,000	$ 5.32	(2,130)
NYMEX Henry Hub	3,750,000	$ 7.13	3,509
2011			
IF EL PASO	1,470,000	$ 6.40	40
IF HSC	360,000	$ 9.01	678
IF NGPL	480,000	$ 5.98	(213)
IF RELIANT	1,860,000	$ 5.96	(772)
IF TETCO STX	870,000	$ 6.76	67
NYMEX Henry Hub	2,130,000	$ 6.72	(201)
All gas swaps	28,110,000		$ 30,344

Gas Collars				
Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at September 30, 2009 Asset/(Liability)
	(MMBtu)	(per MMBtu)	(per MMBtu)	(In thousands)
Fourth quarter 2009				
IF CIG	600,000	$ 4.75	$ 8.82	$ 431
IF HSC	210,000	$ 5.57	$ 9.49	241
IF PEPL	1,385,000	$ 5.30	$ 9.25	1,434
NYMEX Henry Hub	90,000	$ 6.00	$ 10.35	118
2010				
IF CIG	2,040,000	$ 4.85	$ 7.08	81
IF HSC	600,000	$ 5.57	$ 7.88	158
IF PEPL	4,945,000	$ 5.31	$ 7.61	1,110
NYMEX Henry Hub	240,000	$ 6.00	$ 8.38	106
2011				
IF CIG	1,800,000	$ 5.00	$ 6.32	(818)
IF HSC	480,000	$ 5.57	$ 6.77	(236)
IF PEPL	4,225,000	$ 5.31	$ 6.51	(1,882)
NYMEX Henry Hub	120,000	$ 6.00	$ 7.25	(36)
All gas collars	16,735,000			$ 707

Natural Gas Liquid Contracts

Natural Gas Liquid Swaps			
Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at September 30, 2009 Asset
	(Bbls)	(per Bbl)	(In thousands)
Fourth quarter 2009	70,000	$ 45.95	$ 744
2010	140,000	$ 49.59	2,227
2011	20,000	$ 49.01	280
All natural gas liquid swaps	230,000		$ 3,251

Hedge Contracts Entered into After September 30, 2009

The following table includes all hedges entered into subsequent to September 30, 2009, through October 27, 2009.

Gas Contracts

Gas Swaps		
Contract Period	Volumes	Weighted-Average Contract Price
	(MMBtu)	(per MMBtu)
2010		
IF ANR OK	460,000	$ 5.61
IF CIG	320,000	$ 5.66
IF PEPL	1,020,000	$ 5.50
IF RELIANT	570,000	$ 5.78
2011		
IF ANR OK	500,000	$ 6.10
IF CIG	780,000	$ 6.01
IF NGPL	560,000	$ 6.17
IF PEPL	900,000	$ 6.12
IF RELIANT	2,120,000	$ 6.30
2012		
IF ANR OK	360,000	$ 6.18
IF NGPL	660,000	$ 6.34
IF PEPL	2,730,000	$ 6.25
IF RELIANT	900,000	$ 6.38
All gas swaps	11,880,000	

Natural Gas Liquid Contracts

Natural Gas Liquid Swaps		
Contract Period	Volumes	Weighted-Average Contract Price
	(Bbls)	(per Bbl)
Fourth quarter 2009	43,000	$ 36.78
2010	245,000	$ 36.78

2011	292,000	$	37.80
2012	136,000	$	38.33
All natural gas liquid swaps	716,000		

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

Summary of Interest Rate Risk

Market risk is estimated as the potential change in fair value resulting from an immediate hypothetical one percentage point parallel shift in the yield curve. For fixed-rate debt, interest rate changes affect the fair market value but do not impact results of operations or cash flows. Conversely, interest rate changes for floating-rate debt generally do not affect the fair market value but do impact future results of operations and cash flows, assuming other factors are held constant. The carrying amount of our floating-rate debt typically approximates its fair value. We had $235.0 million of floating-rate debt outstanding as of September 30, 2009. Our fixed-rate debt outstanding, net of debt discount, at this same date was $264.8 million.

Off-Balance Sheet Arrangements

As part of our ongoing business, we have not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. As of September 30, 2009, we have not been involved in any unconsolidated SPE transactions.

We evaluate our transactions to determine if any variable interest entities exist. If it is determined that we are the primary beneficiary of a variable interest entity, that entity is consolidated into our consolidated financial statements.

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 for the year ended December 31, 2008, and to the footnote disclosures included in Part I, Item 1 of this report.

New Accounting Pronouncements

Please see Note 3 – Recent Accounting Pronouncements, Note 7 – Long-term Debt, Note 8 – Derivative Financial Instruments, and Note 11 – Fair Value Measurements under Part I, Item 1 of this report for new accounting matters.

Environmental

St. Mary’s compliance with applicable environmental regulations has to date not resulted in significant capital expenditures or material 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 future expenditures will be required under the existing regulatory framework. However, we are unable to predict the impact that compliance with future laws or regulations, such as those currently being considered as discussed below, may have on future capital expenditures, liquidity, and results of operations.

The U.S. Congress is currently considering legislation that would amend the Safe Drinking Water Act to eliminate an existing exemption from federal regulation of hydraulic fracturing activities. Hydraulic fracturing is a common process in our industry of creating artificial cracks, or fractures, in deep underground rock formations through the pressurized injection of water, sand and other additives to enable oil or natural gas to move more easily through the rock pores to a production well. This process is often necessary to produce commercial quantities of oil and natural gas from many reservoirs, especially shale rock formations. We routinely utilize hydraulic fracturing in many of our reservoirs, and our Eagle Ford, Haynesville, Marcellus and Woodford shale programs utilize or contemplate the utilization of hydraulic fracturing. Currently, regulation of hydraulic fracturing is primarily conducted at the state level through permitting and other compliance requirements. If adopted, the proposed amendment to the Safe Drinking Water Act could result in additional regulations and permitting requirements at the federal level. Those additional regulations and permitting requirements, as well as other regulatory developments at the state level, could lead to significant operational delays and increased operating costs, and make it more difficult to perform hydraulic fracturing.

The U.S. House of Representatives recently passed the American Clean Energy and Security Act of 2009, which would establish a federal cap-and-trade system whereby major sources of greenhouse gas emissions would be required to acquire emission allowances, which could be done through purchases at auctions or through trades with other allowance holders, and then surrender the allowances to the government. If a regulated party could not acquire sufficient allowances or reduce its emissions to the level of allowances that it did acquire, the party would face regulatory penalties. This legislation would initially cover electrical generation facilities and would phase in coverage of other industrial sources of emissions and natural gas and fossil fuel distribution. If this or similar legislation is enacted into law, or if any other program to tax the emission of greenhouse gases is adopted, it could have a material adverse effect on our operations through significant increases in operating costs and decreases in the demand for oil and natural gas.

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 with respect to our financial condition, results of operations, or economic performance that we expect, believe, or anticipate will or may occur in the future, or that address plans and objectives of management for future operations, are forward-looking statements. The words "anticipate," "assume," "believe," "budget," "estimate," "expect," "forecast," "intend," "plan," "project 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 activities and 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 natural gas production estimates
- Our outlook on future oil and natural gas prices and service costs
- Cash flows, anticipated liquidity, and the future repayment of debt
- Business strategies and other plans and objectives for future operations, including plans for expansion and growth of operations or to defer capital investment, and our outlook on our future financial condition or results of operations
- Other similar matters such as those discussed in the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section of this Form 10-Q.

Our forward-looking statements are based on assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments, and other factors that we believe are appropriate under the circumstances. These statements are subject to a number of known and unknown risks and uncertainties which may cause our actual results and performance to be materially different from any future results or performance expressed or implied by the forward-looking statements. These risks are described in the "Risk Factors" section of our 2008 Annual Report on Form 10-K and subsequent Quarterly Reports on Form 10-Q, including this Form 10-Q, and include such factors as:

- The volatility and level of realized oil and natural gas prices
- A contraction in demand for oil and natural gas as a result of adverse general economic conditions
- The availability of economically attractive exploration, development, and property acquisition opportunities and any necessary financing, including constraints on the availability of opportunities and

financing due to currently distressed capital and credit market conditions

- Our ability to replace reserves and sustain production

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- Unexpected drilling conditions and results
- Unsuccessful exploration and development drilling
- The risks of hedging strategies, including the possibility of realizing lower prices on oil and natural gas sales as a result of commodity price risk management activities
- The pending nature of reported divestiture plans for certain non-core oil and gas properties as well as the ability to complete divestiture transactions
- The uncertain nature of the expected benefits from acquisitions and divestitures of oil and natural gas properties, including uncertainties in evaluating oil and natural gas reserves of acquired properties and associated potential liabilities, and uncertainties with respect to the amount of proceeds that may be received from divestitures
- The imprecise nature of oil and natural gas reserve estimates
- Uncertainties inherent in projecting future rates of production from drilling activities and acquisitions
- Declines in the values of our oil and natural gas properties resulting in impairment charges and write-downs
- 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, and the risk that one or more of these parties may not satisfy their contractual commitments
- The negative impact that lower oil and natural gas prices could have on our ability to borrow and fund capital expenditures
- The potential effects of increased levels of debt financing
- Our ability to compete effectively against other independent and major oil and natural 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 performance 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, Summary of Oil and Gas Production Hedges in Place, and Summary of Interest Rate Risk 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 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, 2009, there have been no material changes from the risk factors as previously disclosed in our Form 10-K for the year ended December 31, 2008, in response to Item 1A of Part I of such Form 10-K.

Proposed federal legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

The U.S. Congress is currently considering legislation that would amend the Safe Drinking Water Act to eliminate an existing exemption from federal regulation of hydraulic fracturing activities. Hydraulic fracturing is a common process in our industry of creating artificial cracks, or fractures, in deep underground rock formations through the pressurized injection of water, sand and other additives to enable oil or natural gas to move more easily through the rock pores to a production well. This process is often necessary to produce commercial quantities of oil and natural gas from many reservoirs, especially shale rock formations. We routinely utilize hydraulic fracturing techniques in many of our reservoirs, and our Eagle Ford, Haynesville, Marcellus, and Woodford shale programs utilize or contemplate the utilization of hydraulic fracturing. Currently, regulation of hydraulic fracturing is primarily conducted at the state level through permitting and other compliance requirements. If adopted, the proposed amendment to the Safe Drinking Water Act could result in additional regulations and permitting requirements at the federal level. Those additional regulations and permitting requirements, as well as other regulatory developments at the state level, could lead to significant operational delays and increased operating costs, and make it more difficult to perform hydraulic fracturing.

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

(c) The following table provides information about purchases by the Company or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the fiscal quarter ended September 30, 2009, of shares of the Company's common stock, which is the sole class of equity securities registered by the Company pursuant to Section 12 of the Exchange Act.

PURCHASES OF EQUITY SECURITIES BY ISSUER
AND AFFILIATED PURCHASERS

Period		(a) Total Number of Shares Purchased (1)	(b) Average Price Paid per Share		(c) Total Number of Shares Purchased as Part of Publicly Announced Program	(d) Maximum Number of Shares that May Yet Be Purchased Under the Program (2)
	07/01/09 –07/31/09	324	$	23.75	-0-	3,072,184
	08/01/09 – 08/31/09	-	$	-	-0-	3,072,184
	09/01/09 – 09/30/09	88	$	28.97	-0-	3,072,184
Total:		412	$	24.86	-0-	3,072,184

(1) Includes 412 shares withheld (under the terms of grants under the Equity Incentive Compensation Plan) to offset tax withholding obligations that occur upon the delivery of outstanding shares underlying restricted stock units.

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

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

ITEM 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 and Restricted Stock Unit Award Agreement (filed as Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, and incorporated herein by reference)
10.2†	St. Mary Land & Exploration Company Form of Performance Share and Restricted Stock Unit Award Notice (filed as Exhibit 10.6 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, and incorporated herein by reference)
10.3*†	Third Amendment to St. Mary Land & Exploration Company Employee Stock Purchase Plan dated September 23, 2009
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 18 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 agreement.

SIGNATURES

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

ST. MARY LAND & EXPLORATION COMPANY

November 3, 2009	By: /s/ ANTHONY J. BEST Anthony J. Best President and Chief Executive Officer
November 3, 2009	By: /s/ A. WADE PURSELL A. Wade Pursell Executive Vice President and Chief Financial Officer
November 3, 2009	By: /s/ MARK T. SOLOMON Mark T. Solomon Controller