ST MARY LAND & EXPLORATION CO
Form 10-Q
August 04, 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 June 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 July 28, 2009 the registrant had 62,497,724 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)

	June 30, 2009	December 31, 2008 (As adjusted, Note 7)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10,389	$ 6,131
Short-term investments	-	1,002
Accounts receivable, net of allowance for doubtful accounts of $16,941 in 2009 and $16,788 in 2008	108,384	157,690
Refundable income taxes	-	13,161
Prepaid expenses and other	14,111	22,161
Accrued derivative asset	67,143	111,649
Total current assets	200,027	311,794
Property and equipment (successful efforts method), at cost:		
Land	1,371	1,350
Proved oil and gas properties	2,916,495	2,969,722
Less - accumulated depletion, depreciation, and amortization	(1,047,505)	(947,207)
Unproved oil and gas properties, net of impairment allowance of $51,774 in 2009 and $42,945 in 2008	156,011	168,817
Wells in progress	38,079	90,910
Materials inventory, at lower of cost or market	37,565	40,455
Oil and gas properties held for sale less accumulated depletion, depreciation, and amortization	48,410	1,827
Other property and equipment, net of accumulated depreciation of $15,652 in 2009 and $13,848 in 2008	15,274	13,458
	2,165,700	2,339,332
Other noncurrent assets:		
Accrued derivative asset	10,668	21,541
Restricted cash subject to Section 1031 Exchange	-	14,398
Other noncurrent assets	19,344	10,182
Total other noncurrent assets	30,012	46,121
Total Assets	$ 2,395,739	$ 2,697,247

LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities:				
Accounts payable and accrued expenses	$	207,342	$	254,811
Accrued derivative liability		23,583		501
Deferred income taxes		16,938		41,289
Total current liabilities		247,863		296,601
Noncurrent liabilities:				
Long-term credit facility		275,000		300,000
Senior convertible notes, net of unamortized discount of $24,763 in 2009, and $28,787 in 2008		262,737		258,713
Asset retirement obligation		85,882		108,755
Asset retirement obligation associated with oil and gas properties held for sale		9,336		238
Net Profits Plan liability		156,524		177,366
Deferred income taxes		280,144		354,328
Accrued derivative liability		54,198		27,419
Other noncurrent liabilities		12,627		11,318
Total noncurrent liabilities		1,136,448		1,238,137
Commitments and contingencies				
Stockholders' equity:				
Common stock, $0.01 par value: authorized - 200,000,000 shares; issued: 62,622,664 shares in 2009 and 62,465,572 shares in 2008; outstanding, net of treasury shares: 62,495,771 shares in 2009 and 62,288,585 shares in 2008		626		625
Additional paid-in capital		145,972		141,283
Treasury stock, at cost: 126,893 shares in 2009 and 176,987 shares in 2008		(1,256)		(1,892)
Retained earnings		858,135		957,200
Accumulated other comprehensive income		7,951		65,293
Total stockholders' equity		1,011,428		1,162,509
Total Liabilities and Stockholders' Equity	$	2,395,739	$	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 June 30, 2009	For the Three Months Ended June 30, 2008 (As adjusted, Note 7)	For the Six Months Ended June 30, 2009	For the Six Months Ended June 30, 2008 (As adjusted, Note 7)
Operating revenues and other income:				
Oil and gas production revenue	$ 145,279	$ 399,961	$ 275,696	$ 710,393
Realized oil and gas hedge gain (loss)	43,279	(68,396)	98,899	(92,346)
Gain on sale of proved properties	1,244	3,038	645	59,055
Marketed gas system and other operating revenue	15,396	22,339	29,178	41,942
Total operating revenues and other income	205,198	356,942	404,418	719,044
Operating expenses:				
Oil and gas production expense	49,465	73,625	105,294	133,101
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	70,391	76,354	162,103	146,708
Exploration	19,490	17,401	33,088	31,709
Impairment of proved properties	6,043	9,566	153,092	9,566
Abandonment and impairment of unproved properties	11,631	2,056	15,533	3,064
Impairment of materials inventory	2,719	-	11,335	-
General and administrative	18,160	21,867	34,559	43,004
Bad debt expense	-	9,951	-	9,942
Change in Net Profits Plan liability	2,449	68,142	(20,842)	81,768
Marketed gas system expense	13,609	20,213	26,992	37,958
Unrealized derivative (gain) loss	11,288	(1,186)	13,134	5,231
Other expense	5,814	702	11,456	1,402

Total operating expenses	211,059	298,691	545,744	503,453
Income (loss) from operations	(5,861)	58,251	(141,326)	215,591
Nonoperating income (expense):				
Interest income	105	59	127	156
Interest expense	(7,663)	(7,243)	(13,759)	(13,836)
Income (loss) before income taxes	(13,419)	51,067	(154,958)	201,911
Income tax benefit (expense)	5,097	(18,598)	59,013	(74,468)
Net income (loss)	$ (8,322)	$ 32,469	$ (95,945)	$ 127,443
Basic weighted-average common shares outstanding	62,418	61,714	62,377	62,287
Diluted weighted-average common shares outstanding	62,418	62,749	62,377	63,404
Basic net income (loss) per common share	$ (0.13)	$ 0.53	$ (1.54)	$ 2.05
Diluted net income (loss) per common share	$ (0.13)	$ 0.52	$ (1.54)	$ 2.01

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 withholdings	482,602	5	(6,910)	-	-	-	-	(6,905)
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	-	-	-	-	-	(95,945)	-	(95,945)
Change in derivative instrument fair value	-	-	-	-	-	-	(11,852)	(11,852)
Reclassification to earnings	-	-	-	-	-	-	(45,494)	(45,494)
Minimum pension liability adjustment	-	-	-	-	-	-	4	4
Total comprehensive loss								(153,287)
Cash dividends, $ 0.05 per share	-	-	-	-	-	(3,120)	-	(3,120)
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	86,505	1	(3,249)	-	-	-	-	(3,248)
Sale of common stock, including income tax benefit of stock option exercises	19,570	-	207	-	-	-	-	207
Stock-based compensation expense	1,250	-	6,873	50,094	636	-	-	7,509
Balances, June 30, 2009	62,622,664	$626	$145,972	(126,893)	$(1,256)	$858,135	$7,951	$1,011,428

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 Six Months Ended June 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)	$ (95,945)	$ 127,443
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Gain on sale of proved properties	(645)	(59,055)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	162,103	146,708
Exploratory dry hole expense	4,667	6,606
Impairment of proved properties	153,092	9,566
Abandonment and impairment of unproved properties	15,533	3,064
Impairment of materials inventory	11,335	-
Stock-based compensation expense*	7,509	7,057
Bad debt expense	-	9,942
Change in Net Profits Plan liability	(20,842)	81,768
Unrealized derivative (gain) loss	13,134	5,231
Loss related to hurricanes	7,120	-
Amortization of debt discount and deferred financing costs	5,703	4,606
Deferred income taxes	(63,148)	54,762
Other	(736)	876
Changes in current assets and liabilities:		
Accounts receivable	49,149	(71,854)
Refundable income taxes	13,161	(8,921)
Prepaid expenses and other	(7,091)	(6,570)
Accounts payable and accrued expenses	(12,338)	14,850
	-	(9,565)

Excess income tax benefit from the exercise of stock options					
Net cash provided by operating activities		241,761			316,514	
Cash flows from investing activities:					
Proceeds from sale of oil and gas properties		1,081			154,597	
Capital expenditures		(215,826	)		(329,666	)
Acquisition of oil and gas properties		(44	)		(62,927	)
Receipts from restricted cash		14,398			-	
Deposits to restricted cash		-			(25,266	)
Deposits to short-term investments		1,002			173	
Other		-			(9,987	)
Net cash used in investing activities		(199,389	)		(273,076	)
Cash flows from financing activities:					
Proceeds from credit facility		1,766,000			638,000	
Repayment of credit facility		(1,791,000	)		(628,000	)
Debt issuance costs related to credit facility		(11,060	)		-	
Excess income tax benefit from the exercise of stock options		-			9,565	
Proceeds from sale of common stock		1,066			10,684	
Repurchase of common stock		-			(77,202	)
Dividends paid		(3,120	)		(3,076	)
Net cash used in financing activities		(38,114	)		(50,029	)
Net change in cash and cash equivalents		4,258			(6,591	)
Cash and cash equivalents at beginning of period		6,131			43,510	
Cash and cash equivalents at end of period	$	10,389		$	36,919	

* Stock-based compensation expense is a component of exploration expense and general and
administrative expense on the consolidated statements of operations. For the six months ended June 30, 2009,
and 2008, respectively, approximately $2.9 million and $2.2 million of stock-based compensation
expense was included in exploration expense. For the six months ended June 30, 2009, and 2008,

respectively, approximately $4.6 million and $4.9 million of stock-based compensation expense was included in general and administrative expense.

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

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

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

	For the Six Months Ended June 30, 2009	For the Six Months Ended June 30, 2008
	(In thousands)	
Cash paid for interest	$ 8,837	$ 11,720
Cash paid or (refunded) for income taxes	$ (10,441)	$ 18,687

For the period ended June 30, 2008, the Company issued 427,607 restricted stock units to employees as equity-based compensation, pursuant to the Company's Equity Incentive Compensation Plan. The total fair value of this issuance was $23.3 million.

As of June 30, 2009, and 2008, $57.9 million, and $140.0 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 commons stock from treasury to its non-employee directors pursuant to the Company's Equity Incentive Compensation Plan. The Company recorded compensation expense related to non-employee director shares of approximately $636,000, and $803,000 for the six-month periods ended June 30, 2009 and 2008, respectively.

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

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

June 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 and offshore in the Gulf of Mexico.

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 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 preparation of the condensed consolidated financial statements of St. Mary and in accordance with the recently issued Statement of Financial Accounting Standards ("SFAS") No. 165 "Subsequent Events" ("SFAS No. 165"), the Company evaluated subsequent events after the balance sheet date of June 30, 2009, through the filing of this report on August 4, 2009.

On January 1, 2009, the Company adopted Financial Accounting Standards Board ("FASB") Staff Position ("FSP") Accounting Principles Board Opinion ("APB") 14-1, "Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement)" ("FSP APB 14-1"), which required retrospective application. As a result, prior period balances presented have been adjusted to reflect the period-specific effects of applying FSP APB 14-1. 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 and the Company acquires materials inventory for use in future drilling or repair operations. Materials inventory is valued at the lower of cost or market. Materials inventory totaled $37.6 million and $40.5 million at June 30, 2009, and December 31, 2008, respectively. The Company incurred net materials inventory write-downs for the three-month and six-month periods ended June 30, 2009, totaling $2.7 million and $11.3 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 six-month periods ended June 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 consolidated financial statements be read in conjunction with the consolidated financial statements and notes included in St. Mary's Form 10-K for the year ended December 31, 2008.

Note 3 – Recent Accounting Pronouncements

The Company adopted SFAS No. 141(R), "Business Combinations" ("SFAS No. 141(R)") on January 1, 2009, which requires the acquiring entity in a business combination to recognize and measure all assets and liabilities assumed in the transaction and any non-controlling interest in the acquiree at fair value as of the acquisition date. SFAS No. 141(R) 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 require possible recognition of goodwill given differences between the purchase price and fair value of assets received. The impact of SFAS No. 141(R) 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.

The Company adopted FSP SFAS No. 141(R)-1, "Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies" ("FSP 141(R)-1") on January 1, 2009, which amends the guidance in SFAS No. 141(R) relating to the initial recognition and measurement, subsequent measurement and accounting, and disclosures of assets and liabilities arising from contingencies in a business combination. The impact of FSP 141(R)-1 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.

The Company adopted SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements – an amendment to ARB No. 51" on January 1, 2009, which 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 adoption of this pronouncement did not have a material impact on the Company's consolidated financial statements.

On April 1, 2009, the Company adopted FSP SFAS 107-1 and APB No. 28-1, "Interim Disclosures about Fair Value of Financial Instruments" ("FSP 107-1"). FSP 107-1 amends SFAS No. 107, "Disclosures about Fair Value of Financial Instruments," and APB No. 28, "Interim Financial Reporting," which requires an entity to provide disclosures about fair value of financial instruments in interim financial information. FSP 107-1 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 adoption of this pronouncement did not have any material impact on the Company's consolidated financial statements.

The Company adopted SFAS No. 165 on April 1, 2009, which 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. SFAS No. 165 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 adoption of this pronouncement did not have a material impact on the Company's consolidated financial statements.

In December 2008 the Securities and Exchange Commission ("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 is a widely accepted standard for the management of petroleum resources developed by several industry organizations. 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 SEC will require companies to comply with the amended disclosure requirements 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 SEC is working with the FASB to facilitate corresponding accounting standard revisions, which may affect the adoption date. The Company is currently assessing the impact that the adoption will have on the Company's consolidated financial statements and disclosures.

In December 2008 the FASB issued FSP SFAS No. 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets" ("FSP 132(R)-1"). FSP 132(R)-1 amends the disclosure requirements of plan assets for defined benefit pensions and other postretirement plans. The objective of FSP 132(R)-1 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. FSP 132(R)-1 will be effective for fiscal years ending after December 15, 2009. The Company will adopt the new disclosure requirements in Form 10-K for the fiscal year ending December 31, 2009. The Company is currently assessing the impact that the adoption will have on the Company's consolidated financial statements and disclosures.

In June 2009 the FASB issued SFAS No. 168, "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles, a replacement of FASB Statement No. 162" ("SFAS No. 168"). SFAS No. 168 establishes the FASB Accounting Standards Codification as the source of authoritative U.S. generally accepted accounting principles ("GAAP") recognized by the FASB to be applied to rules and interpretive releases of the SEC under federal securities laws as authoritative GAAP for SEC registrants. SFAS No. 168 is effective for interim and annual periods ending on or after September 15, 2009. The adoption of this pronouncement is not anticipated to have a material impact 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 recently adopted accounting standards.

Note 4 – Earnings per Share

Basic net income per common share of stock is calculated by dividing net income available to common stockholders by the weighted-average basic common shares outstanding for the respective period. The shares represented by vested restricted stock units ("RSUs") are included in the calculation of the weighted-average basic common shares outstanding. The earnings per share calculations reflect the impact of any repurchases of shares of common stock made by the Company.

Diluted net income per common share of stock is calculated by dividing adjusted net income by the weighted-average diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted earnings per share calculations consist of unvested RSUs, in-the-money outstanding options to purchase the Company's common stock, Performance Share Awards ("PSAs"), and shares into which the 3.50% Senior Convertible Notes due 2027 (the "3.50% Senior Convertible Notes") are convertible.

The Company's 3.50% Senior Convertible Notes, which were issued April 4, 2007, have a net-share settlement right whereby each $1,000 principal amount of notes may be surrendered for conversion to cash in an amount equal to the principal amount and, if applicable, shares of common stock for the amount in excess of the principal amount. The treasury stock method is used to measure the potentially dilutive impact of shares associated with that conversion feature. The 3.50% Senior Convertible Notes have not been dilutive for any reporting period that they have been outstanding and therefore do not impact the diluted earnings per share calculation for the three-month or six-month periods ended June 30, 2009, and 2008.

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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 measure 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 six-month periods ended June 30, 2009, and 2008. For additional discussion on 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 SFAS No. 128, "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 six-month periods ended June 30, 2009. The unvested RSUs and in-the-money options had a dilutive impact for the three-month and six-month periods ended June 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 June 30,		For the Six Months Ended June 30,	
	2009	2008 (As adjusted, Note 7)	2009	2008 (As adjusted, Note 7)
	(In thousands, except per share amounts)			
Net income (loss)	$ (8,322)	$ 32,469	$ (95,945)	$ 127,443
Basic weighted-average common stock outstanding	62,418	61,714	62,377	62,287
Add: dilutive effect of stock options, unvested RSUs, and PSAs	-	1,035	-	1,117
Add: dilutive effect of 3.50% senior convertible notes	-	-	-	-
Diluted weighted-average common shares outstanding	62,418	62,749	62,377	63,404
Basic net income (loss) per common share	$ (0.13)	$ 0.53	$ (1.54)	$ 2.05
Diluted net income (loss) per common share	$ (0.13)	$ 0.52	$ (1.54)	$ 2.01

Note 5 – Compensation Plans

Cash Bonus Plan

The Company paid $6.0 million for cash bonuses earned in the 2008 performance year and $3.5 million for cash bonuses earned in the 2007 performance year during the first quarter of 2009 and 2008, respectively. Included in the general and administrative expense and exploration expense line items in the accompanying consolidated statements of operations was $2.9 million and $2.7 million of cash bonus expense related to the specific performance year for the three-month periods ended June 30, 2009, and 2008, respectively, and $5.3 million and $4.5 million for the six-month periods ended June 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 and six-month periods ended June 30, 2009, was $1.1 million and $2.5 million, respectively. There was no stock-based compensation expense related to PSAs for the three-month or six-month periods ended June 30, 2008.

A summary of the status and activity of PSAs for the six-month period ended June 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	-	$ -
Vested	-	$ -
Forfeited	(22,547)	$ 26.48
Non-vested, at June 30, 2009	441,786	$ 26.48

Subsequent to June 30, 2009, the Company granted PSAs. A total of 725,092 PSAs were granted on August 1, 2009. The PSAs represent the right to receive, upon settlement of the PSAs after the completion of the three-year performance period ending June 30, 2012. The PSAs will vest 1/7th on August 1, 2010, 2/7ths on August 1, 2011, and 4/7ths on August 1, 2012.

Restricted Stock Incentive Program Under the Equity Incentive Compensation Plan

The total RSU compensation expense for the three-month periods ended June 30, 2009, and 2008, was $1.7 million and $3.0 million, respectively, and $3.8 million and $6.0 million for the six-month periods ended June 30, 2009, and 2008, respectively. As of June 30, 2009, there was $8.5 million of total unrecognized compensation expense related to unvested RSU awards. The unrecognized compensation expense is being amortized through 2011.

During the first half of 2009, the Company converted 125,284 RSUs, which relate to those awards granted in 2008, 2007, and 2006, into 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 87,755 shares of common stock associated with these grants. The remaining 37,529 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 six-month period ended June 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	-	$ -
Vested	(119,426)	$ 34.99
Forfeited	(16,686)	$ 53.92
Non-vested, at June 30, 2009	266,185	$ 53.82

As of June 30, 2009, a total of 267,418 RSUs were outstanding, of which 1,233 were vested.

Subsequent to June 30, 2009, the Company granted RSUs. A total of 241,745 RSUs were granted on August 1, 2009. Each RSU represents a right to receive one share of the Company's common stock to be delivered upon settlement of the vested RSUs. The RSUs will 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 six-month activity for stock options outstanding as of June 30, 2009:

	Options		Weighted-Average Exercise Price	Weighted Average Remaining Contractual Term (In years)		Aggregate Intrinsic Value (In thousands)
Outstanding, beginning of period	1,509,710	$	12.69			
Exercised	(19,570)	$	10.56			
Forfeited	(45,050)	$	13.38			
Outstanding, end of period	1,445,090	$	12.70	3.21	$	11,803
Vested, or expect to vest, end of period	1,445,090	$	12.70	3.21	$	11,803
Exercisable, end of period	1,445,090	$	12.70	3.21	$	11,803

As of June 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 $517,000 and $673,000 of compensation expense for the three-month periods ended June 30, 2009, and 2008, and $636,000 and $803,000 for the six-month periods ended June 30, 2009, and 2008, respectively.

Employee Stock Purchase Plan

Under the St. Mary Land & Exploration Company Employee Stock Purchase Plan (the "ESPP"), eligible employees may purchase shares of the Company's common stock through payroll deductions of up to 15 percent of eligible compensation. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on the first or last day of the purchase period, and shares issued under the ESPP are restricted for a period of 18 months from the date issued. The ESPP is intended to qualify under Section 423 of the 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 June 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 half of 2009 and 2008, respectively. The Company expensed $390,000 and $90,000 for the three-month periods ended June 30, 2009, and 2008, respectively and $541,000 and $165,000 for the six-month periods ended June 30, 2009, and 2008, respectively based on the estimated fair value on the respective grant date.

Net Profits Plan

Cash payments made under the Net Profits Interest Bonus Plan (“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 June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
	(In thousands)			
General and administrative expense	$ 4,541	$ 9,332	$ 7,774	$ 17,865
Exploration expense	471	3,038	877	5,217
Total	$ 5,012	$ 12,370	$ 8,651	$ 23,082

Additionally, the Company made cash payments under the Net Profits Plan of $1.6 million and $12.4 million for the three-month and six-month periods ended June 30, 2008, respectively, as a result of sales proceeds from the Abraxas and Greater Green River Basin divestitures that closed during the first half of 2008. The cash payments are accounted for as a reduction in the gain on sale of proved properties in the accompanying consolidated statements of operations. There were no cash payments made under the Net Profits Plan as a result of divestitures during the first half of 2009.

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. Of the changes recorded under the Net Profits Plan, nine percent and 25 percent would have been classified as exploration expense in the accompanying unaudited consolidated statements of operations for the three-month periods ended June 30, 2009, and 2008, respectively, and 10 percent and 23 percent would have been classified as exploration expense in the accompanying unaudited consolidated statements of operations for the six-month periods ended June 30, 2009, and 2008, respectively. 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 June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
	(In thousands)			
General and administrative expense (benefit)	$ 2,218	$ 51,406	$ (18,730)	$ 63,288
Exploration expense (benefit)	231	16,736	(2,112)	18,480
Total	$ 2,449	$ 68,142	$ (20,842)	$ 81,768

Note 6 – Income Taxes

Income tax expense (benefit) for the six-month periods ended June 30, 2009, and 2008, differs from the amount that would be provided by applying the statutory U.S. federal income tax rate to income before income taxes as a result of the estimated effect of the domestic production activities deduction, percentage depletion, the effect of state income taxes, and other permanent differences.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
	(In thousands)			
Current portion of income tax expense:				
Federal	$ 2,166	$ 12,859	$ 3,249	$ 18,740
State	495	466	886	966
Deferred portion of income tax expense (benefit):	(7,758)	5,273	(63,148)	54,762
Total income tax expense (benefit)	$ (5,097)	$ 18,598	$ (59,013)	$ 74,468
Effective tax rates	38.0%	36.4%	38.1%	36.9%

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. Currently 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, and the impact of potential permanent state differences have impacted 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 2004. The Internal Revenue Service completed its 2005 audit in March 2009 with a refund due to the Company of $278,000 plus interest of $41,000. These amounts were received and 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.

During the second half of 2009, the U.S. Congress will give consideration to a 2010 budget. Current proposals to fund proposed programs the Administration include eliminating or reducing current deductions for intangible drilling costs, the manufacturer's deduction, and percentage depletion. Legislation eliminating these deductions would increase the Company's current income tax expense, increase the Company's effective tax rate and reduce operating cash flows thereby reducing funding available for St. Mary's exploration and development capital programs. These funding reductions would also impact the Company's peers in the industry and could potentially have a significant adverse effect on drilling in the United States for a number of years.

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 as of the date of this filing is $900 million and is subject to regular semi-annual redeterminations. The borrowing base redetermination process considers the value of St. Mary’s oil and gas properties and other assets, as determined by the bank syndicate. The Company has 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 June 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 $275.0 million and $255.0 million outstanding under its revolving credit agreement as of June 30, 2009, and July 28, 2009, respectively. The Company had $401.7 million and $421.7 million of available borrowing capacity under this facility as of June 30, 2009, and July 28, 2009, respectively. The Company has a single letter of credit outstanding in the amount of $1.3 million as of June 30, 2009, and through the date of this filing. This letter of credit reduces the amount available under the commitment amount on a dollar-for-dollar basis.

Adoption of FSP APB 14-1

On January 1, 2009, the Company adopted FSP APB 14-1. FSP APB 14-1 requires 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. FSP APB 14-1 applies to the Company's 3.50% Senior Convertible Notes. Upon adopting the provisions of FSP APB 14-1 the Company retrospectively applied its provisions and restated the Company's consolidated financial statements for prior periods.

In applying FSP APB 14-1, $42 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 would have been the Company's borrowing rate for a similar debt instrument without the conversion feature 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, 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 of 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
Deferred income taxes	354,328	358,334
Additional paid-in capital	141,283	99,440
Retained earnings	957,200	964,019

As of June 30, 2009, and December 31, 2008, the carrying value of the equity component was $42 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 June 30, 2009	As of December 31, 2008 (Adjusted)
	(In thousands)	
3.50% Senior Convertible Notes	$ 287,500	$ 287,500
Unamortized debt discount	(24,763)	(28,787)
Net carrying amount of the 3.50% Senior Convertible Notes	$ 262,737	$ 258,713

The remaining unamortized debt discount will be recognized under the interest method over the next 33 months.

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

	For the Three Months Ended June 30, 2008		For the Six Months Ended June 30, 2008	
	As Adjusted	As Originally Reported	As Adjusted	As Originally Reported
	(In thousands except per share amounts)			
Interest expense	$ 7,243	$ 5,528	$ 13,836	$ 10,499
Income tax expense	18,598	19,232	74,468	75,702
Net income	32,469	33,550	127,443	129,546
Basic net income per common share	$ 0.53	$ 0.54	$ 2.05	$ 2.08
Diluted net income per common share	$ 0.52	$ 0.53	$ 2.01	$ 2.04

The Company recognized $2.0 million and $1.9 million of non-cash interest expense relating to the debt discount for the three months ended June 30, 2009, and 2008, respectively, and $4.0 million and $3.8 million for the six months ended June 30, 2009, and 2008, respectively. Accumulated amortization related to the debt discount was $17.1 million as of June 30, 2009.

Note 8 – Derivative Financial Instruments

Adoption of SFAS No. 161

On January 1, 2009, the Company adopted SFAS No. 161, “Disclosures about Derivative Instruments and Hedging Activities - an amendment of FASB Statement No. 133” (“SFAS No. 161”). SFAS No. 161 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 under SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities” (“SFAS No. 133”) 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, 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 June 30, 2009, the Company has hedge contracts in place through mid-2012 for a total of approximately 7 million Bbls of anticipated crude oil production, 52 million MMBtu of anticipated natural gas production, and 447,000 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 SFAS No. 133 and related pronouncements. The Company formally documents all relationships between the derivative instruments and the hedged production, as well as the Company’s risk management objective and strategy for the particular derivative contracts. This process includes linking all derivatives that are designated as cash flow hedges to the specific forecasted sale of oil or gas at its physical location. The Company also formally assesses (both at the derivative’s inception and on an ongoing basis) whether the derivatives being utilized have been highly effective 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 June 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 evaluations 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 SFAS No. 133 was a net asset of $30,000 and $105.3 million at June 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 June 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	$ 67,143	$ 111,649
Oil, natural gas, and NGL commodity	Other noncurrent assets	10,668	21,541
Total derivative assets designated as cash flow hedges under SFAS No. 133		$ 77,811	$ 133,190
Derivative liabilities designated as cash flow hedges:			
Oil, natural gas, and NGL commodity	Current liabilities	$ (23,583)	$ (501)
Oil, natural gas, and NGL commodity	Noncurrent liabilities	(54,198)	(27,419)
Total derivative liabilities designated as cash flow hedges under SFAS No. 133		$ (77,781)	$ (27,920)

The Company realized a net gain of $43.3 million and a net loss of $68.4 million from its oil and natural gas derivative contracts for the three months ended June 30, 2009, and 2008, respectively and realized a net gain of $98.9 million and a net loss of $92.3 million from its oil and natural gas derivative contracts for the six months ended June 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 recognized in earnings upon the sale of the hedged production. As of June 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 statement of operations in the next twelve months is $30.6 million.

Any change in fair value resulting from ineffectiveness is recognized currently in unrealized derivative loss in the accompanying consolidated statements of operations. Unrealized derivative loss for the three months ended June 30, 2009, and 2008, includes a net loss of $11.3 million and a net gain of

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$1.2 million, respectively, from ineffectiveness related to oil and natural gas derivative contracts. Unrealized derivative loss for the six months ended June 30, 2009, and 2008, includes net losses of $13.1 million and $5.2 million, respectively, from ineffectiveness related to oil and natural gas derivative contracts.

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 seeks to minimize ineffectiveness by entering into oil derivative contracts indexed to the New York Mercantile Exchange West Texas Intermediate ("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.

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

	Derivatives Qualifying as Cash Flow Hedges	Location of (Gain) Loss Reclassified from AOCI to Income (Effective Portion)	For the Six Months Ended June 30,	
			2009	2008
			(In thousands)	
Amount of (Gain) Loss on Derivatives Recognized in OCI (Effective Portion)	Commodity hedges	Realized oil and gas hedge gain (loss)	$ (11,852)	$ (451,893)
Amount of (Gain) Loss Reclassified from AOCI to Income (Effective Portion)	Commodity hedges	Realized oil and gas hedge gain (loss)	$ (45,494)	$ 58,698

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 June 30,		For the Six Months Ended June 30,	
		2009	2008	2009	2008
		(In thousands)			
Commodity hedges	Unrealized derivative (gain) loss	$ 11,288	$ (1,186)	$ 13,134	$ 5,231

Credit Related Contingent Features

As of June 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, and the liability balance above which the Company is required to post collateral varies from one dollar to an unlimited amount. With the other non-member bank, the Company is required to post collateral if the liability balance exceeds $5.0 million. The Company had $3.6 million and $4.9 million of collateral posted with non-member banks as of June 30, 2009, and July 28, 2009, respectively.

Convertible Note Derivative Instruments

The contingent interest provision of the 3.50% Senior Convertible Notes is a derivative instrument. As of June 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 components of the net periodic cost for both the Qualified Pension Plan and the Nonqualified Pension Plan:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
	(In thousands)			
Service cost	$ 625	$ 460	$ 1,250	$ 920
Interest cost	233	222	467	443
Expected return on plan assets	(107)	(168)	(215)	(335)
Amortization of net actuarial loss	93	40	186	80
Net Periodic benefit cost	$ 844	$ 554	$ 1,688	$ 1,108

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 plans to contribute $1.9 million during 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 June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
	(In thousands)			
Beginning asset retirement obligation	$ 118,018	$ 103,981	$ 116,274	$ 108,284
Liabilities incurred	184	2,060	540	6,089
Liabilities settled	(2,170)	(1,873)	(5,176)	(12,470)
Accretion expense	2,209	1,718	4,510	3,383
Revision to estimated cash flow	5,010	600	7,103	1,200
Ending asset retirement obligation	$ 123,251	$ 106,486	$ 123,251	$ 106,486

As of June 30, 2009, accounts payable and accrued expenses contain $28.0 million related to the Company's current asset retirement obligation liability. These estimated retirement costs are associated with the estimated retirement of some of the Company's offshore platforms.

The Company recorded a loss related to hurricanes of $5.0 million and $7.1 million for the three-month and six-month periods ended June 30, 2009, respectively, which is due to an increase in the estimated remediation costs and a reduction in the estimated insurance proceeds relating to the Vermilion 281 platform that was lost in Hurricane Ike.

Note 11 – Fair Value Measurements

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

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

Effective January 1, 2009, the Company adopted SFAS No. 157 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 SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," ("SFAS No. 144") and asset retirement obligations initially measured at fair value under SFAS No. 143, "Accounting for Asset Retirement Obligations" ("SFAS No. 143"). The adoption of SFAS No.157 for nonfinancial assets and liabilities did not have a material impact on the Company's financial statements.

The following is a listing of the Company's financial and nonfinancial assets and liabilities and where they are classified within the hierarchy as of June 30, 2009.

	Level 1	Level 2	Level 3
		(In thousands)	
Assets:			
Accrued derivative(a)	$ -	$ 77,811	$ -
Proved oil and gas properties(b)	$ -	$ -	$ -
Liabilities:			
Accrued derivative(a)	$ -	$ 77,781	$ -
Net Profits Plan(a)	$ -	$ -	$ 156,524

(a) This represents a financial asset or liability that is measured at fair value on a recurring basis.
(b) This represents a nonfinancial asset or liability that is measured at fair value on a nonrecurring basis. The Company recorded $6.0 million of proved property impairments for properties located in the Gulf of Mexico during the second quarter of 2009. As of June 30, 2009, there was no carrying value for these assets included in the proved oil and gas properties line item in the accompanying consolidated balance sheets. The Company uses level 3 inputs to measure these assets at fair value.

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

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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 provide 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 SFAS No. 157 and with other marketplace participants, the Company recognizes that third parties may use different methodologies or assumptions to determine the fair value of certain financial instruments that could result in a different estimate of fair value at the reporting date.

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 June 30, 2009, would differ by approximately $12 million. A one percentage point decrease in the discount rate would result in an increase to the liability of approximately $9 million, while a one percentage point increase in the discount rate would result in a decrease to the liability of approximately $8 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 the management estimates as described within this footnote. While some inputs to the Company's calculation of the fair value of the Net Profits Plan's future payments are from published sources, others, such as the discount rate and the expected future cash flows, are derived from the Company's own calculations and estimates. The following table reflects the activity for the liabilities measured at fair value using Level 3 inputs for the three-month and six-month periods ended June 30, 2009, and 2008.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
	(In thousands)			
Beginning balance	$ 154,075	$ 225,032	$ 177,366	$ 211,406
Net increase (decrease) in liability (a)	7,461	82,127	(12,192)	117,283
Net settlements (a)(b)	(5,012)	(13,985)	(8,650)	(35,515)
Transfers in (out) of Level 3	-	-	-	-
Ending balance	$ 156,524	$ 293,174	$ 156,524	$ 293,174

(a) Net changes in the Net Profits Plan liability are shown in the Change in Net Profits Plan liability line item of the accompanying consolidated statements of operations.
(b) Settlements represent cash payments made or accrued 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 $241.5 million and $204.0 million as of June 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 SFAS No. 144. 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 June 30, 2009. The Company adopted SFAS No. 157 for all 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 SFAS No. 143. 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 June 30, 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 $6.0 million of proved property impairments during the second quarter of 2009. The impairments were associated with proved properties in the Gulf of Mexico. The Company recorded a total of $153.1 million of proved property impairments during the first six months of 2009. A significant decrease in the market price for natural gas during the first quarter, including differentials in effect at March 31, 2009, caused the majority of this non-cash impairment of proved properties. The largest portion of the impairment was $97.3 million related to assets located in the Mid-Continent region. The Company recorded $9.6 million of proved property impairments for both the three-month and six-month periods ended June 30, 2008, which related to a write-down of assets located at the Apple Springs Field in Louisiana.

The Company recorded $11.6 million of abandonment and impairment of unproved properties in the second quarter of 2009 for a total of $15.5 million for the six months ended June 30, 2009. The largest portion of this impairment was related to Floyd Shale acreage located in Mississippi. The Company recorded $2.1 million and $3.1 million of abandonment and impairment of unproved properties, respectively, for the three-month and six-month periods ended June 30, 2008.

Note 13 – Assets Held for Sale

As of June 30, 2009, the Company is engaged in marketing for sale certain non-core oil and gas properties. In accordance with SFAS No. 144, these properties have been separately presented in the balance sheet at the lower of carrying value or estimated fair value less the cost to sell. The accompanying consolidated balance sheet as of June 30, 2009, presents $48.4 million of assets held for sale, net of accumulated depletion, depreciation and amortization. Assets held for sale were measured at carrying value, which was less than estimated fair value less cost to sell as of June 30, 2009. 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. Asset retirement obligation liabilities of $9.3 million related to these properties have also been reclassified to liabilities associated with oil and gas properties held for sale on the consolidated balance sheet as of June 30, 2009. The Company determined that these sales do not qualify for discontinued operations accounting under FASB Emerging Issues Task Force Issue No. 03-13 "Accounting for the Impairment or Disposal of Long-Lived Assets".

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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 adoption of FSP APB 14-1. Please refer to Note 7 – Long-term Debt within Part 1, 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 and offshore Gulf of Mexico. We have developed a balanced and diverse portfolio of proved reserves, development drilling opportunities, and unconventional resource prospects.

Our mission is to deliver outstanding net asset value per share growth to our investors via attractive oil and gas investments. Historically, we have 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, in 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 standing and liquidity have become increasingly important as concerns have been raised regarding the pace of drilling activity in the exploration and production industry and the ability of companies to fund their planned activity. In addition, fears of a prolonged global recession or depression leading to declining energy demand have resulted in a significant decline in oil and natural gas prices. We expect our remaining 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 second quarters of 2009 and 2008 and the first quarter of 2009.

	For the Three Months Ended		
	June 30, 2009	March 31, 2009	June 30, 2008
Crude Oil (per Bbl):			
Average NYMEX price	$ 59.62	$ 43.08	$ 123.98
Realized price, before the effects of hedging	$ 53.96	$ 34.40	$ 120.20
Net realized price, including the effects of hedging	$ 56.72	$ 44.16	$ 88.40
Natural Gas (per Mcf):			
Average NYMEX price	$ 3.72	$ 4.86	$ 10.80
Realized price, before the effects of hedging	$ 3.07	$ 4.00	$ 10.83
Net realized price, including the effects of hedging	$ 5.19	$ 6.14	$ 9.97

Average quarterly NYMEX crude oil prices increased 38 percent from the first quarter of 2009 to the second quarter of 2009 from $43.08 per barrel to $59.62 per barrel. The 36-month forward strip price for crude oil also increased 22 percent to $76.46 per barrel at the end of the second quarter of 2009 compared with $62.79 per barrel at the end of the first quarter of 2009. The increase appears to be related to a more positive view of future oil demand, as well as the weakening of the U.S. dollar and announced production cuts by OPEC. On July 28, 2009, the 36-month forward strip price had increased from the end of the second quarter 2009 by one percent to $76.95 per barrel. At the same time, the near month price was $67.23 per barrel, which was four percent lower than the June 30, 2009, near month price of $69.89 per barrel.

Average quarterly NYMEX natural gas prices decreased 23 percent from the first quarter of 2009 to the second quarter of 2009 from $4.86 per Mcf to $3.72 per Mcf. Natural gas prices have been under downward pressure due to concerns regarding high levels of natural gas in storage, and anemic demand related to current economic conditions fueling concerns of over-supply in the market. The 36-month forward strip price for natural gas at the end of the first quarter of 2009 was $5.97 per MMBtu. At the end of the second quarter of 2009, the 36-month forward contract price had increased by six percent to $6.33 per MMBtu. As of July 28, 2009, the 36-month forward strip price had decreased four percent to $6.07 per MMBtu. At the same time, the near month price had decreased from the June 30, 2009 near month price of $3.84 per MMBtu by an additional eight percent to $3.54 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 contracts 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 six months ended June 30, 2009, were positively impacted by $78.3 million and $20.6 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. Taking into account all oil and gas production hedge contracts in place at June 30, 2009, we have hedged anticipated future production of approximately 7 million Bbls of oil, 52 million MMBtu of natural gas, and 447,000 Bbls of natural gas liquids through the middle of 2012. 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 swings 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 SFAS No. 133 and related pronouncements. Changes in the value of our hedge positions are primarily reflected in our consolidated balance sheets. A small 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 $11.3 million in non-cash derivative loss in the second quarter primarily as a result of increases in the price of oil shifting previous oil hedge assets into hedge liabilities, previous hedge ineffectiveness gains on hedge assets to become ineffectiveness losses from 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 that we use to hedge and otherwise manage our financial risks related to swings in oil and gas commodity prices.

Second 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 in 2007 through 2009 through a combination of property acquisitions, leasing activity, and participation in a joint venture with industry partners. Lastly, late in 2008 we entered into two arrangements that allow us to earn or purchase acreage in the Marcellus shale in north central Pennsylvania.

During the second quarter of 2009, testing continued in several of the emerging resource plays in which we have exposure. In Webb County, Texas we successfully completed our first operated horizontal Eagle Ford shale well. We also assumed operatorship of a joint venture between ourselves and two industry partners in the second quarter. This program is currently testing the potential of the Eagle Ford shale. Between the joint venture and our other acreage holding, we currently have a total of 225,000 net acres with potential for the Eagle Ford shale in Dimmitt, LaSalle, Maverick, and Webb counties in Texas. We operated two drilling rigs in the program for much of the second quarter. After fulfilling our 2009 acreage earning commitments in the joint venture, we released one of these rigs. Currently, one operated rig is drilling on high working interest acreage outside of the joint venture area. For the remainder of 2009, we anticipate completing two previously drilled wells and plan to drill an additional six wells on our 100 percent working interest acreage.

Early in the second quarter we announced the results of our first operated horizontal well in the Haynesville shale play of eastern Texas and northern Louisiana. This well is located in DeSoto Parish, Louisiana. We believe the completion of the well was compromised by faulting in the area and its performance did not meet our expectations. During the quarter, we drilled our second well targeting the Haynesville shale in northern San Augustine County, Texas. The well is awaiting completion pending core and logging analysis, and it is anticipated that we will complete the well vertically. Approximately 40,000 net acres of our total 50,000 net acres with exposure to the Haynesville shale are located in eastern Texas, with the largest portion being located along the border between San Augustine and Shelby Counties. We plan to drill one additional well targeting the Haynesville shale in eastern Texas later this year and will continue to participate with partners in non-operated wells.

In the Marcellus shale program in Pennsylvania, we exercised our lease option on approximately 25,000 net acres late in the second quarter. We now have over 40,000 net acres in north central Pennsylvania with potential for the Marcellus shale. At the end of the quarter, we had begun drilling our first operated horizontal well in McKean County. We plan to drill one additional well in 2009 to further test our acreage.

Downward pressure on cost structure. During the second quarter, reductions in costs that have long been anticipated by the exploration and production industry for the drilling, completion, and operation of oil and gas properties began to occur. While costs for these services are still highly dependent on specific regional factors, we have seen significant reductions in the cost to drill and complete wells in response to the slowdown of drilling activity. Lease operating costs also are decreasing as a result of the slowdown in the exploration and production industry, as well as weakness in the broader economy.

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

	Mid-Continent	ArkLaTex	Gulf Coast	Permian	Rocky Mountain	Total (1)
Second Quarter 2009 Production:						
Oil (MBbl)	74.3	38.0	105.3	495.7	935.1	1,648.4
Gas (MMcf)	9,068.4	3,733.9	1,724.4	1,083.3	2,719.3	18,329.3
Equivalent (MMCFE)	9,514.2	3,962.1	2,356.3	4,057.3	8,329.6	28,219.5
Avg. Daily Equivalents (MMCFE/d)	104.6	43.5	25.9	44.6	91.5	310.1
Relative percentage	34%	14%	8%	14%	30%	100%

(1) Totals may not add due to rounding

For the second quarter of 2009 our oil and gas production and revenues were slightly better than originally budgeted. We saw strong production performance from a majority of our regions during the quarter. However, production has declined over the last two quarters as a result of lower levels of capital investment. Our ability to fund capital investments is influenced significantly by the price we receive for produced oil and natural gas, which have declined significantly since mid-2008, resulting in reduced operating cash flows for 2009. Prices for these commodities have been and are expected to remain volatile. We plan to fund our 2009 capital investments primarily from our operating cash flows, which are expected to be significantly lower in 2009 compared to 2008. As a result, we anticipate sequential decline in production over the next couple of quarters.

First Six Months 2009 Highlights

Impairments. We have recognized significant non-cash impairments during the first half of 2009, the majority of which occurred in the first quarter of the year. During the second quarter, 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. Our total impairment of proved properties for the six months ended June 30, 2009, totaled $153.1 million. We 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 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 that were significantly impacted by wider than normal differentials at that time. During the second quarter, we recognized a charge of $11.6 million for the abandonment and impairment of unproved properties primarily associated with our Floyd shale leasehold in Mississippi. We have recognized $15.5 million for the abandonment and impairment of unproved properties for the six-month period ended June 30, 2009. Lastly, we incurred inventory write-downs in the second quarter of $2.7 million for a total of $11.3 million for the six-month period ended June 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 six months ended June 30, 2009, the change in the value of this liability resulted in a non-cash benefit of $20.8 million compared to non-cash expense of $81.8 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 $8.7 million and $35.5 million for the six months ended June 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 in Part I, Item 1. An increasing percentage of the costs associated with the payments for 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 June 30, 2009, would differ by approximately $12 million. A one percentage point decrease in the discount rate would result in an increase to the liability of approximately $9 million, while a one percentage point increase in the discount rate would result in a decrease to the liability of approximately $8 million. We frequently re-evaluate the assumptions used in our calculations and consider the possible impacts stemming from the current market environment including current and future oil and gas prices, discount rates, and overall market conditions.

Production results. The table below details the regional breakdown of our first half of 2009 production.

	Mid-Continent	ArkLaTex	Gulf Coast	Permian	Rocky Mountain	Total (1)
First six months of 2009 Production:						
Oil (MBbl)	147.9	73.6	197.7	1,005.1	1,863.8	3,288.1
Gas (MMcf)	17,764.3	7,810.5	3,660.8	2,069.9	5,539.0	36,844.5
Equivalent (MMCFE)	18,651.8	8,251.9	4,847.0	8,100.6	16,721.9	56,573.2
Avg. Daily Equivalents (MMCFE/d)	103.0	45.6	26.8	44.8	92.4	312.6
Relative percentage	33%	14%	9%	14%	30%	100%

(1) Totals may not add due to rounding

For the first half 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

Unlike prior years, we entered 2009 without a specific capital budget for exploration and development activities. Our plan for the remainder of 2009 is to make capital investments for exploration and development activities at a level at or near our operating cash flows. Given the volatility of commodity prices in recent months, we have established a flexible capital program that can be quickly adjusted rather than setting a fixed budget.

Our first priority in the current environment is to focus our limited capital dollars on the testing of emerging resource plays. Our second priority is the rational development of existing assets. We believed a significant decline in commodity prices would cause the exploration and production industry to slow its level of activity. We have seen this occur, and as a result the United States natural gas rig count has declined approximately 58 percent from its peak of over 1,600 rigs in the third quarter of 2008 to its current level of approximately 675. This in turn has led to a decline in the cost of services provided by the oilfield service industry, and we have seen this trend accelerate throughout the second quarter. Prices for drilling and completion services have declined significantly during the year as a result of continued declines in rig utilization. Accordingly, we elected to defer much of our capital investment in development programs with the goal of improving our returns on invested capital. Our lack of significant long-term rig commitments and limited meaningful near term leasehold expiry allowed us to quickly slow our drilling activity. In recent months, in response to the reduction in drilling and completion costs and an increase in oil prices, we have shifted more of our development activity to primarily oil producing properties. We have recently added a drilling rig in our Wolfberry tight oil program in the Permian Basin and we plan to add a second rig in the basin later this year. Additionally, the Company plans to operate a drilling rig in the Williston Basin beginning in September of this year that will focus on oil-weighted Bakken and Three Forks projects.

With respect to development activity focused on natural gas projects, we remain selective with our capital investment given the current price environment. In our exploration program, we continue to test the potential in the emerging resource plays to which we have exposure. In the Eagle Ford shale, we plan to have one rig operate in the play for the remainder of 2009. This rig will operate on high working interest acreage in the southern part of our acreage holdings. Our goal is to delineate our acreage position in order to allow for a more rational development program should the play concept prove successful. In the Haynesville shale, our plans for the remainder of the year include completing the first well drilled on our acreage as well as drilling and completing our second East Texas Haynesville well. In the Marcellus shale, we plan to have two wells drilled and completed by the end of 2009.

Financial Results of Operations and Additional Comparative Data

We recorded a net loss of $8.3 million or ($0.13) per diluted share for the three months ended June 30, 2009, compared to second quarter 2008 results of net income of $32.5 million or $0.52 per diluted share.

The table below provides information regarding selected production and financial information for the quarter ended June 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			
	June 30, 2009	March 31, 2009	December 31, 2008	September 30, 2008
	(In millions, except production sales data)			
Production (BCFE)	28.2	28.4	30.0	27.7
Oil and gas production revenue, excluding the effects of hedging	$ 145.3	$ 130.4	$ 190.5	$ 358.5
Realized oil and gas hedge gain (loss)	$ 43.3	$ 55.6	$ 44.8	$ (53.5)
Lease operating expense	$ 35.6	$ 41.2	$ 47.7	$ 43.6
Transportation costs	$ 4.6	$ 5.5	$ 6.1	$ 6.6
Production taxes	$ 9.3	$ 9.1	$ 11.8	$ 22.5
DD&A	$ 70.4	$ 91.7	$ 95.1	$ 72.4
Exploration	$ 19.5	$ 13.6	$ 17.7	$ 10.7
Impairment of proved properties	$ 6.0	$ 147.0	$ 292.1	$ 0.5
Abandonment and impairment of unproved properties	$ 11.6	$ 3.9	$ 34.7	$ 1.2
Impairment of materials inventory	$ 2.7	$ 8.6	$ -	$ -
Impairment of goodwill	$ -	$ -	$ 9.5	$ -
General and administrative expense	$ 18.2	$ 16.4	$ 12.4	$ 24.1
Bad debt expense	$ -	$ -	$ -	$ 6.7
Change in Net Profits Plan liability	$ 2.4	$ (23.3)	$ (80.9)	$ (34.9)
Unrealized derivative (gain) loss	$ 11.3	$ 1.8	$ (12.0)	$ (4.4)
Net income (loss)	$ (8.3)	$ (87.6)	$ (127.1)	$ 87.0
Percentage change from previous quarter:				
Production (BCFE)	(1)%	(5)%	8%	(3)%
Oil and gas production revenue, excluding the effects	11%	(32)%	(47)%	(10)%

of hedging				
Realized oil and gas hedge gain (loss)	(22)%	24%	(184)%	(22)%
Lease operating expense	(14)%	(14)%	9%	6%
Transportation costs	(16)%	(10)%	(8)%	18%
Production taxes	2%	(23)%	(48)%	(17)%
DD&A	(23)%	(4)%	31%	(5)%
Exploration	43%	(23)%	65%	(39)%
Impairment of proved properties	(96)%	(50)%	N/M	(95)%
Abandonment and impairment of unproved properties	197%	(89)%	N/M	(43)%
Impairment of materials inventory	(69)%	N/A	N/A	N/A
Impairment of goodwill	N/A	(100)%	N/A	N/A
General and administrative expense	11%	32%	(49)%	10%
Bad debt expense	N/A	N/A	(100)%	(33)%
Change in Net Profits Plan liability	(110)%	(71)%	132%	(151)%
Unrealized derivative (gain) loss	528%	(115)%	173%	267%
Net income (loss)	(91)%	(31)%	(246)%	168%

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 in recent quarters. This reduction in activity has begun to diminish the upward cost pressure we had seen in recent years and we anticipate that oil and gas production expenses in absolute dollars will decrease throughout the remainder of 2009. Production taxes are largely dependent on the prices we receive for oil and natural gas. Depreciation, depletion, and amortization generally has 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 half of 2009, we have seen our DD&A rate fluctuate as a result of swings in commodity prices that impact impairments and proved reserve volumes. Additionally, the accounting treatment for high DD&A per MCFE gas assets that are currently classified as assets held for sale lowered our DD&A rate significantly in the second quarter. Our general and administrative expense will be impacted by cash payments made under the Net Profits Plan, which generally reflect our realized commodity prices. Part of executing our business plan has required the addition of employees, particularly lease operators who manage our operations in the field.

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

Selected Operations Data (In thousands, except sales price, volume, and per MCFE amounts):	For the Three Months Ended June 30, 2009	For the Three Months Ended June 30, 2008	Percent Change Between Periods	For the Six Months Ended June 30, 2009	For the Six Months Ended June 30, 2008	Percent Change Between Periods
Net production volumes						
Oil (MBbl)	1,648	1,644	-%	3,288	3,312	(1)%
Natural gas (MMcf)	18,329	18,684	(2)%	36,844	37,027	-%
MMCFE (6:1)	28,219	28,551	(1)%	56,573	56,898	(1)%
Average daily production						
Oil (Bbl per day)	18,114	18,071	-%	18,166	18,197	-%
Natural gas (Mcf per day)	201,422	205,322	(2)%	203,561	203,443	-%
MCFE per day (6:1)	310,104	313,748	(1)%	312,559	312,626	-%
Oil & gas production revenues (1)						
Oil production revenue	$ 93,487	$ 145,365	(36)%	$ 165,900	$ 272,493	(39)%
Gas production revenue	95,071	186,200	(49)%	208,695	345,554	(40)%
Total	$ 188,558	$ 331,565	(43)%	$ 374,595	$ 618,047	(39)%
Oil & gas production expense						
Lease operating expense	$ 35,602	$ 40,975	(13)%	$ 76,850	$ 76,080	1%
Transportation costs	4,568	5,624	(19)%	10,027	9,501	6%
Production taxes	9,295	27,026	(66)%	18,417	47,520	(61)%
Total	$ 49,465	$ 73,625	(33)%	$ 105,294	$ 133,101	(21)%
Average realized sales price (1)						
Oil (per Bbl)	$ 56.72	$ 88.40	(36)%	$ 50.45	$ 82.28	(39)%
Natural gas (per Mcf)	$ 5.19	$ 9.97	(48)%	$ 5.66	$ 9.33	(39)%
Per MCFE Data:						
Average net realized price (1)	$ 6.68	$ 11.61	(42)%	$ 6.62	$ 10.86	(39)%
Lease operating expenses	(1.26)	(1.43)	(12)%	(1.36)	(1.33)	2%
Transportation costs	(0.16)	(0.20)	(20)%	(0.18)	(0.17)	6%

Production taxes	(0.33)	(0.95)	(65)%	(0.33)	(0.84)	(61)%
General and administrative	(0.64)	(0.77)	(17)%	(0.61)	(0.76)	(20)%
Operating profit	$ 4.29	$ 8.26	(48)%	$ 4.14	$ 7.76	(47)%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$ 2.49	$ 2.67	(7)%	$ 2.87	$ 2.58	11%

(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 downward move in commodity prices over the last year while our cost structure has remained relatively steady. Our operating margin of $4.29 for the second quarter of 2009 per MCFE decreased 48 percent from the $8.26 we realized in the second quarter of 2008. However, it has increased seven percent from the $4.03 per MCFE reported for the first quarter of this year.

We experienced a decline in our operating margins in the first half of 2009, compared with the same period in 2008, due to a decrease in commodity prices and increases in operating costs. For the six months ended June 30, 2009, our operating margin was $4.14 per MCFE compared to $7.76 per MCFE for the same period in 2008.

Average daily production for the first six months of 2009 remained the same at 312.6 MMCFE compared with the same period in 2008. For the six months ended June 30, 2009, our average net realized price decreased $4.24 per MCFE to $6.62 per MCFE compared with the same period in 2008. Lower commodity prices were the principal driver of the decrease in the first half of 2009, compared with same period in 2008. Unit costs decreased for the period as production taxes decreased $0.51 per MCFE to $0.33 per MCFE and general and administrative expense decreased $0.15 per MCFE to $0.61 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. These decreases in costs were offset by a $0.03 per MCFE increase in lease operating expenses year over year. Transportation costs also increased $0.01 per MCFE, or six percent to $0.18 per MCFE as compared to the same period in 2008.

For the six months ended June 30, 2009, depletion, depreciation, and amortization, including asset retirement obligation accretion expense, increased $0.29 per MCFE to $2.87 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 six months of 2009 was $33.1 million, which was four percent higher than the $31.7 million incurred during the first six months of 2008. Geological and geophysical expense increased $7.6 million due to an increase in the amount spent for seismic analysis. This increase was offset by a $4.3 million decrease in exploration overhead due to a decrease in Net Profits Plan payments resulting from decreased oil and gas commodity prices and a $1.9 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):			Percent Change Between Periods
	June 30, 2009	December 31, 2008	
Working capital (deficit)	$ (47,836)	$ 15,193	(415)%
Long-term debt	$ 537,737	$ 558,713	(4)%
Stockholders' equity	$ 1,011,428	$ 1,162,509	(13)%

	For the Three Months Ended June 30,		Percent Change Between Periods	For the Six Months Ended June 30,		Percent Change Between Periods
	2009	2008		2009	2008	
Basic net income (loss) per common share	$ (0.13)	$ 0.53	(125)%	$ (1.54)	$ 2.05	(175)%
Diluted net income (loss) per common share	$ (0.13)	$ 0.52	(125)%	$ (1.54)	$ 2.01	(177)%
Basic weighted-average shares outstanding	62,418	61,714	(1)%	62,377	62,287	-%
Diluted weighted-average shares outstanding	62,418	62,749	(1%)	62,377	63,404	(2)%

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 six months or three months ended June 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 June 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 19,570 and 812,376 shares of common stock during the six-month periods ended June 30, 2009, and 2008, respectively, as a result of stock option exercises. The first half 2008 share issuances 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 six months of 2009. Additionally, the number of RSUs that vested during the first six months of 2009 and 2008 were 119,426 and 196,245, respectively.

Additional Comparative Data in Tabular Form:

	Change Between the Three Months Ended June 30, 2009, and 2008	Change Between the Six Months Ended June 30, 2009, and 2008
Decrease in oil and gas production revenues, net of hedging (In thousands)	$ 143,007	$ 243,452

Components of revenue increases (decreases):

Oil		
Realized price change per Bbl, including the effects of hedging	$ (31.68)	$ (31.83)
Realized price percentage change	(36)%	(39)%
Production change (MBbl)	4	(24)
Production percentage change	-%	(1)%
Natural Gas		
Realized price change per Mcf, including the effects of hedging	$ (4.78)	$ (3.67)
Realized price percentage change	(48)%	(39)%
Production change (MMcf)	(355)	(183)
Production percentage change	(2)%	-%

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
Revenue	2009	2008	2009	2008
Oil	50%	44%	44%	44%
Natural gas	50%	56%	56%	56%
Production				
Oil	35%	35%	35%	35%
Natural gas	65%	65%	65%	65%

Information regarding the components of exploration expense:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008

Summary of Exploration Expense	(In millions)			
Geological and geophysical expenses	$ 6.3	$ 1.4	$ 10.7	$ 3.1
Exploratory dry hole expense	4.6	5.9	4.7	6.6
Overhead and other expenses	8.6	10.1	17.7	22.0
Total	$ 19.5	$ 17.4	$ 33.1	$ 31.7

Information regarding the effects of oil and gas hedging activity:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
Oil Hedging				
Percentage of oil production hedged	47%	63%	48%	60%
Oil volumes hedged (MBbl)	782	1,044	1,569	1,997
Increase (decrease) in oil revenue	$ 4.6 millionn	$ (52.3 million)	$ 20.6 million	$ (79.1 million)
Average realized oil price per Bbl before hedging	$ 53.96	$ 120.20	$ 44.21	$ 106.17
Average realized oil price per Bbl after hedging	$ 56.72	$ 88.40	$ 50.45	$ 82.28
Natural Gas Hedging				
Percentage of gas production hedged	49%	43%	49%	41%
Natural gas volumes hedged (MMBtu)	$ 9.6 million	$ 8.6 million	$ 19.0 million	$ 16.1 million
Increase (decrease) in gas revenue	$ 38.7 million	$ (16.1 million)	$ 78.3 million	$ (13.2 million)
Average realized gas price per Mcf before hedging	$ 3.07	$ 10.83	$ 3.54	$ 9.69
Average realized gas price per Mcf after hedging	$ 5.19	$ 9.97	$ 5.66	$ 9.33

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

Oil and gas production revenue. Average daily production decreased one percent to 310.1 MMCFE for the quarter ended June 30, 2009, compared with 313.7 MMCFE for the quarter ended June 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)	Pre-Hedge Oil and Gas Revenues Lost	Production Costs Decrease
	(MMCFE)	(In millions)	(In millions)
Mid-Continent	19.1	$ (53.1)	$ (6.3)
ArkLaTex	(3.6)	(39.2)	(0.6)
Gulf Coast	(21.6)	(42.5)	(4.9)
Permian	6.3	(32.2)	(0.5)
Rocky Mountain	(3.8)	(87.7)	(11.9)
Total	(3.6)	$ (254.7)	$ (24.2)

Our daily production decreased slightly for the second quarter of 2009 compared to the same period in 2008. The largest regional increase occurred in the Mid-Continent region as a result of the success in the Woodford shale assets 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. Our organic increases offset most of a decrease in the Gulf Coast region's production caused primarily by an exchange of assets that occurred in late 2008 whereby we received an increased interest in assets located at Sweetie Peck in exchange for assets located in the Judge Digby Field.

The following table summarizes the average realized prices we received in the second 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 June 30,	
	2009	2008
Realized oil price ($/Bbl)	$ 53.96	$ 120.20
Realized gas price ($/Mcf)	$ 3.07	$ 10.83
Realized equivalent price ($/MCFE)	$ 5.15	$ 14.01

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 $43.3 million for the three-month period ended June 30, 2009, the majority of which related to favorable settlements on gas hedges, compared with a $68.4 million loss for the same period in 2008, which was primarily due to unfavorable settlements on our oil hedges.

Marketed gas system revenue and expense. Marketed gas system revenue, which is included in the line item marketed gas and other operating revenue, decreased $8.1 million to $14.2 million for the quarter ended June 30, 2009, compared with $22.3 million for the comparable period of 2008. Concurrent with the decrease in marketed gas system revenue, marketed gas system expense decreased $6.6 million to $13.6 million for the quarter ended June 30, 2009, compared with $20.2 million for the comparable period of 2008. The net margin has stayed relatively consistent with historical performance. 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 $49.5 million for the first quarter of 2009 from $73.6 million in the comparable period of 2008. Total oil and gas production costs per MCFE decreased $0.83 to $1.75 for the second quarter of 2009, compared with $2.58 for the same period in 2008. This decrease is comprised of the following:

- A $0.62 decrease in production taxes on a per MCFE basis due to the decrease in realized prices between periods

- An $0.11 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 an decrease in transportation costs on our properties located in the Rocky Mountain region

- A $0.06 decrease in overall workover LOE on a per MCFE basis relating to a decrease in workover activity in the Mid-Continent and Gulf Coast regions.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A decreased $6.0 million or eight percent to $70.4 million for the three-month period ended June 30, 2009, compared with $76.4 million for the same period in 2008. DD&A expense per MCFE decreased seven percent to $2.49 for the three-month period ended June 30, 2009, compared to $2.67 for the same

period in 2008. The depletion, depreciation, and amortization decrease is largely a result of our exclusion of higher DD&A expense properties that are currently classified as assets held for sale from the DD&A calculation. Additionally, 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 12 percent to $19.5 million for the three-month period ended June 30, 2009, compared with $17.4 million for the same period in 2008. Geological and geophysical expense increased $4.9 million due to an increase in the amount spent for seismic analysis. This increase was partially offset by a $1.5 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. We recognized $6.0 million for impairment of proved properties in the second quarter of 2009 related principally to impairments of properties in the Gulf of Mexico for which we are relinquishing our ownership interests. This compares to $9.6 million for the same period in 2008 that related to wells located in the Apple Springs Field in the ArkLaTex.

Abandonment and impairment of unproved properties. A charge of $11.6 million was recognized in the second quarter of 2009 for abandonment and impairment of unproved properties. This charge related primarily to the write-off of Floyd shale acreage. This compares to a charge of $2.1 million that was recognized for the same period in 2008.

General and administrative. General and administrative expense decreased $3.7 million or 17 percent to $18.2 million for the quarter ended June 30, 2009, compared with $21.9 million for the comparable period of 2008. G&A expense per MCFE decreased $0.13 to $0.64 per MCFE for the second quarter of 2009 compared to $0.77 per MCFE for the same period in 2008.

Payments made under the Net Profits Plan decreased $4.8 million for the quarter ended June 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 second quarter of 2009, 17 of our 21 pools are in payout status. No additional pools are expected to reach payout in 2009. This decrease in Net Profits Plan payments was offset by an increase in base employee compensation, including payroll taxes and benefits, of approximately $2.1 million from the second quarter of 2008 to the second quarter of 2009. The increase is a result of an increase in employee head count between the two periods. A significant driver of this headcount increase has been our conversion from contract lease operators to employee lease operators.

Cash bonus and long-term incentive compensation expense remained relatively flat from quarter to quarter. A $1.0 million increase in COPAS overhead reimbursements due was to an increase in our operated well count.

Change in Net Profits Plan liability. For the quarter ended June 30, 2009, this non-cash expense was $2.4 million compared to $68.1 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.

Unrealized derivative (gain) loss. We recognized a loss of $11.3 million in the second quarter of 2009 compared to a gain of $1.2 million in the second 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.

Other expense. Other expense increased $5.1 million to $5.8 million for the quarter ended June 30, 2009, compared with $702,000 for the same period in 2008. In the second quarter of 2009, we incurred an additional loss related to hurricanes of $5.0 million, which relates to a decrease in our estimate of insurance reimbursements related to the Vermillion 281 platform that was lost in Hurricane Ike.

Income tax expense. We recorded a benefit from income tax of $5.1 million for the second quarter of 2009 compared to income tax expense of $18.6 million for the second quarter of 2008 resulting in effective tax rates of 38.0 percent and 36.4 percent, respectively. The change in income tax expense is primarily the result of us recording a loss before income taxes, as discussed above. The 2009 increase in effective tax rate from 2008 reflects changes in the effects of other permanent differences including the domestic production activities deduction and to a lesser extent, changes in the mix of the highest marginal state tax rates as a result of acquisition and drilling activity expected in 2009 versus 2008. Our cash tax expense decreased for the second 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. This trend is expected to continue throughout the remainder of 2009 based upon our current projected capital expenditures program and commodity price outlook. If the U.S Congress passes legislation to reduce or eliminate current deductions for intangible drilling costs, the manufacturer's 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 six months ended June 30, 2009, and 2008

Oil and gas production revenue. Average daily production remained consistent at 312.6 MMCFE for the respective six months ended June 30 in 2009 and 2008. The following table presents the regional changes in our production and oil and gas revenues and costs between the two six 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	15.6	$ (91.4)	$ (8.0)
ArkLaTex	(2.5)	(60.0)	1.2
Gulf Coast	(17.9)	(67.9)	(7.6)
Permian	7.8	(57.7)	0.1
Rocky Mountain	(3.0)	(157.7)	(13.5)
Total	0.0	$ (434.7)	$ (27.8)

Our daily production remained flat for the first six months of 2009 compared to the same period in 2008. The largest regional increases occurred in the Mid-Continent and Permian regions and offset a decrease in the Gulf Coast region which is described in more detail above.

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

	For the Six Months Ended June 30,	
	2009	2008

Realized oil price ($/Bbl)	$	44.21	$	106.17
Realized gas price ($/Mcf)	$	3.54	$	9.69
Realized equivalent price ($/MCFE)	$	4.87	$	12.49

The combination of flat production volumes and lower commodity prices between periods resulted in lower oil and gas revenue. We expect this trend to continue throughout 2009 based on current futures market pricing.

Realized oil and gas hedge gain (loss). We recorded a realized hedge gain of $98.9 million for the six-month period ended June 30, 2009, related to settlements on oil and gas hedges, compared with a $92.3 million loss for the same period in 2008, which was primarily due to unfavorable settlements on our oil hedges.

Marketed gas system revenue and expense. Marketed gas system revenue, which is included in the line item marketed gas and other operating revenue, decreased $13.6 million to $27.6 million for the six-month period ended June 30, 2009, compared with $41.2 million for the comparable period of 2008. Concurrent with the decrease in marketed gas system revenue, marketed gas system expense decreased $11.0 million to $27.0 million for the six-month period ended June 30, 2009, compared with $38.0 million for the comparable period of 2008. The net margin has stayed relatively consistent with historical performance. We expect that marketed gas system revenue and expense will continue to trend with increases and decreases in production and our net realized price.

Gain on sale of proved properties. We had a $645,000 net gain on sale of proved properties for the six-month period ended June 30, 2009, compared with a $59.1 million gain on sale 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.

Oil and gas production expense. Total production costs decreased $27.8 million, or 21 percent, to $105.3 million for the first six months of 2009 from $133.1 million in the comparable period of 2008. Total oil and gas production costs per MCFE decreased $0.47 to $1.87 for the first six months of 2009, compared with $2.34 for the same period in 2008. This decrease is comprised of the following:

- A $0.51 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 $0.06 increase in recurring LOE on a per MCFE basis due to generally higher costs in the first quarter of 2009 and in the oil-weighted Permian region for items such as fuel and fluid disposal, as well as in the ArkLaTex
- A $0.01 increase in overall transportation cost on a per MCFE basis
- A $0.03 decrease in overall workover LOE on a per MCFE basis relating to a decrease in workover activity in the Mid-Continent and Gulf Coast regions.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A increased $15.4 million or ten percent to $162.1 million for the six-month period ended June 30, 2009, compared with $146.7 million for the same period in 2008. DD&A expense per MCFE increased 11 percent to $2.87 for the six-month period ended June 30, 2009, compared to $2.58 for the same period in 2008. The depletion, depreciation, and amortization 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. Additionally, the reserves used in the calculation of DD&A expense are impacted by price. The price for oil and gas that we have seen since mid-2008 has had a downward impact on the amount of proved reserves used by our Company in the calculation of DD&A expense, which has a corresponding upward impact on our DD&A per MCFE.

Exploration. Exploration expense increased four percent to $33.1 million for the six-month period ended June 30, 2009, compared with $31.7 million for the same period in 2008. Geological and

geophysical expense increased $7.6 million due to an increase in the amount spent for seismic analysis. This increase was offset by a $4.3 million decrease in exploration overhead due to 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 to $153.1 million for the six-month period ended June 30, 2009, compared with $9.6 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.

Abandonment and impairment of unproved properties. Abandonment and impairment of unproved properties increased to $15.5 million for the six-month period ended June 30, 2009, compared with $3.1 million for the same period in 2008. The charge related primarily to a write-off of Floyd shale acreage located in Mississippi.

Impairment of materials inventory. We recorded an $11.3 million impairment of materials inventory for the six-month period ended June 30, 2009. There were no impairments recorded for the six-month period ended June 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 $8.4 million or 20 percent to $34.6 million for the six months ended June 30, 2009, compared with $43.0 million for the comparable period of 2008. G&A expense per MCFE decreased $0.15 to $0.61 per MCFE for the first six months of 2009 compared to $0.76 per MCFE for the same six-month period in 2008.

Payments made under the Net Profits Plan decreased $10.1 million for the six months ended June 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. This decrease in Net Profits Plan payments was partially offset by an increase in base employee compensation, including payroll taxes and benefits, of approximately $5.4 million from the first six months of 2008 to the first six months of 2009. The increase is a result of an increase in employee head count. A significant driver of this headcount increase has been our conversion from contract lease operators to employee lease operators. Cash bonus and long-term incentive compensation expense remained relatively flat from year to year.

The above amounts combined with a $600,000 decrease in other G&A expenses, including charitable contributions, were offset by a $3.1 million increase in COPAS overhead reimbursements, which is due to an increase in our operated well count.

Change in Net Profits Plan liability. For the six months ended June 30, 2009, this non-cash item was a benefit of $20.8 million compared to an expense of $81.8 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.

Unrealized derivative (gain) loss. We recognized a loss of $13.1 million for the six months ended June 30, 2009, compared to a loss of $5.2 million 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 $10.1 million to $11.5 million for the six months ended June 30, 2009, compared with $1.4 million for the same period in 2008. In the first quarter of 2009, we incurred $2.6 million of expense related to the assignment of a drilling rig contract in our Rocky Mountain region. We also incurred an additional loss related to hurricanes of $7.1 million for the six months ended June 30, 2009.

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Income tax expense. Income tax benefit totaled $59.0 million for the six-month period of 2009 compared to income tax expense of $74.5 million for the same period of 2008 resulting in effective tax rates of 38.1 percent and 36.9 percent, respectively. The change in income tax expense is primarily the result of us recording a loss before income taxes as discussed above. The 2009 increase in effective tax rate from 2008 reflects changes in other permanent differences including the domestic production activities deduction and to a lesser extent, changes in the mix of the highest marginal state tax rates as a result of acquisition and drilling expected in 2009 versus 2008. Our cash tax expense decreased for the six months ended June 30, 2009, compared to the six months ended June 30, 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.

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 second half 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, debt financing, 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. A decrease in market prices reduces expected cash flow from operating activities and could reduce the borrowing base of our credit facility as well as the value of non-strategic properties we might consider selling. Historically, decreases in market prices have limited our industry’s access to the capital markets. The public debt markets are currently accessible, although at higher costs. Equity and convertible debt financings are still an available alternative. We do not anticipate raising public debt or equity financing in the foreseeable future. We intend to rely on our credit facility for borrowings. However, a significant transaction could necessitate raising additional public debt or equity financing.

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 has been set 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 are monitoring the borrowing environment closely and have frequent discussions with the lending group.

As of July 28, 2009, we had $421.7 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 $1.3 million as of June 30, 2009, and through the date of this filing. Such borrowings and letter of credit reduce the amount available under the commitment amount on a dollar-for-dollar basis. Borrowings under the facility are secured by mortgages on the majority of our oil and gas properties. As of July 28, 2009, we also had approximately $20 million of cash on hand that we could use to further reduce the outstanding balance under our credit facility.

Our weighted-average interest rate in the three-month periods ended June 30, 2009, and 2008, was 5.5 percent and 5.6 percent, respectively. Our weighted-average interest rate in the six-month periods ended June 30, 2009, and 2008, was 4.9 percent and 5.9 percent, respectively. Our weighted-average 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 new amended credit facility, including limitations on dividend payments and requirements to maintain certain financial ratios, which include debt to earnings before interest, taxes, depreciation, and amortization ("EBITDA") of less than 3.5 to 1.0 and a current ratio as defined by our credit agreement of not less than 1.0 to 1.0. These covenants are substantially the same as those under our previous credit facility. As of June 30, 2009, our debt to EBITDA ratio and current ratio as defined by our credit agreement, were 1.08 and 2.38, 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 six months of 2009 we spent $215.8 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 costs 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.

During the second half of 2009, the U.S. Congress will give consideration to a 2010 budget. Current proposals to fund programs proposed by the Administration include eliminating or reducing current deductions for intangible drilling costs, the manufacturer's deduction, and percentage depletion. Legislation 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 affect on drilling in the United States for a number of years.

The following table presents amount and percentage changes in cash flows between the six-month periods ended June 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 Six Months Ended June 30,			Percent
	2009	2008	Change	Change
	(In thousands)			
Net cash provided by operating activities	$ 241,761	$ 316,514	$ (74,753)	(24)%
Net cash used in investing activities	$ 199,389	$ 273,076	$ (73,687)	(27)%
Net cash used in financing activities	$ 38,114	$ 50,029	$ (11,915)	(24)%

Analysis of Cash Flow Changes Between the Six Months Ended June 30, 2009, and June 30, 2008

Operating activities. Cash received from oil and gas production revenue, net of the realized effects of hedging, decreased $185.8 million to $398.9 million for the first six months of 2009, compared with $584.7 million for the first six months of 2008. Included in operating revenues for the six-month period ended June 30, 2009, is $98.9 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 six months of 2009 of $10.4 million compared with net cash income taxes paid of $18.7 million for the same period in 2008.

Investing activities. Cash used for investing activities decreased $73.7 million for the six months ended June 30, 2009, compared with the same period in 2008. Cash outflows for capital expenditures decreased $113.8 million or 35 percent to $215.8 million for the six months ended June 30, 2009, reflecting a reduced level of activity as a result of lower commodity prices. Cash outflow relating to the acquisition of oil and gas properties also decreased $62.9 million to $44,000 for the six months ended June 30, 2009, compared with the same period in 2008 due to reduced activity in acquisition markets during the first six months of 2009. We acquired assets in the Carthage Field during the first half 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 six months ended June 30, 2009, there were no major divestitures compared with the same period in 2008 when we received $154.6 million from the sale of non-core properties to Abraxas.

Financing activities. Net repayments on our credit facility increased by $35.0 million for the six-month period ended June 30, 2009, compared with the same period in 2008. We spent $11.0 million on debt issuance costs for the Company’s amended credit facility during the six-month period ended June 30, 2009. We did not incur any debt issuance costs during the six-month period ended June 30, 2008. We spent $77.2 million to repurchase our common stock during the six-month period ended June 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 Six Months Ended June 30,	
	2009	2008
	(In thousands)	
Development costs (1)	$ 127,624	$ 306,109
Exploration costs	38,730	53,710
Acquisitions		
Proved properties	51	37,578
Unproved properties – acquisitions of proved properties (2)	-	25,696
Unproved properties - other	19,864	13,723
Total, including asset retirement obligations (3)	$ 186,269	$ 436,816

(1) Includes capitalized interest of $1.0 million in 2009 and $2.5 million in 2008.
(2) Represents a portion of the allocated purchase price of unproved properties acquired as part of the acquisition of proved properties.
(3) Includes amounts relating to estimated asset retirement obligations of $506,000 in 2009 and $6.1 million in 2008.

Costs incurred for capital and exploration activities during the first six months of 2009 decreased $250.5 million or 57 percent compared to the same period in 2008. Excluding acquisitions, our development and exploration investments decreased $193.5 million compared to the same period in the prior year. This decrease in capital and exploration activities during the first six 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 into the second half of 2009 and beyond in order to improve returns on invested capital by taking advantage of expected improved commodity prices and/or lower drilling and completion costs.

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 the foreseeable future. The amount and allocation of future capital and exploration expenditures will depend upon a number of factors, including the number and size of available economic acquisition and drilling opportunities, our cash flows from operating and financing activities, and our ability to assimilate leasehold and producing property acquisitions. In addition, the impact of oil and natural gas prices on investment opportunities, the availability of capital and borrowing facilities, and the success of our development and exploratory activities may lead to changes in funding requirements for future development.

Commodity Price Risk and Interest Rate Risk

We are exposed to market risk, including the effects of changes in oil and 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.

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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 June 30, 2009, and through the date of this filing, our hedged positions of anticipated production through mid-2012 totaled approximately 7 million Bbls of oil, 52 million MMBtu of natural gas, and 447,000 Bbls of natural gas liquids.

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 June 30, 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 (Bbl)	Weighted-Average Contract Price (per Bbl)	Fair Value at June 30, 2009 Asset/(Liability) (In thousands)
Third quarter 2009	509,000	$ 71.96	$ 475
Fourth quarter 2009	459,000	$ 72.31	(224)
2010	1,596,000	$ 68.77	(9,886)
2011	1,164,000	$ 67.06	(12,106)
2012	183,000	$ 81.15	220
All oil swaps	3,911,000		$ (21,521)

Oil Collars				
Contract Period	NYMEX WTI Volumes (Bbl)	Weighted-Average Floor Price (per Bbl)	Weighted-Average Ceiling Price (per Bbl)	Fair Value at June 30, 2009 Liability (In thousands)
Third quarter 2009	384,500	$ 50.00	$ 67.31	$ (2,289)
Fourth quarter 2009	384,500	$ 50.00	$ 67.31	(3,552)
2010	1,367,500	$ 50.00	$ 64.91	(18,558)
2011	1,236,000	$ 50.00	$ 63.70	(20,958)
All oil collars	3,372,500			$ (45,357)

Gas Contracts

Gas Swaps			
Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at June 30, 2009 Asset/(Liability)
	(MMBtu)	(per MMBtu)	(In thousands)
Third quarter 2009			
IF ANR OK	100,000	$ 7.11	$ 380
IF CIG	300,000	$ 6.64	1,175
IF EL PASO	300,000	$ 6.94	1,092
IF HSC	2,680,000	$ 8.25	11,910
IF NGPL	100,000	$ 6.86	355
IF PEPL	360,000	$ 7.47	1,529
IF RELIANT	510,000	$ 3.84	249
NYMEX Henry Hub	420,000	$ 7.76	1,609
Fourth quarter 2009			
IF ANR OK	90,000	$ 7.43	284
IF CIG	150,000	$ 7.42	540
IF EL PASO	300,000	$ 7.01	864
IF HSC	2,620,000	$ 8.60	10,602
IF NGPL	90,000	$ 7.14	255
IF RELIANT	810,000	$ 4.34	68
NYMEX Henry Hub	710,000	$ 7.18	1,626
2010			
IF ANR OK	60,000	$ 7.98	152
IF EL PASO	1,090,000	$ 6.79	1,414
IF HSC	6,080,000	$ 8.40	16,393
IF NGPL	990,000	$ 5.51	(123)
IF RELIANT	4,200,000	$ 5.32	(1,001)
NYMEX Henry Hub	3,750,000	$ 7.13	4,031
2011			
IF EL PASO	1,470,000	$ 6.40	325
IF HSC	360,000	$ 9.01	777
IF NGPL	480,000	$ 5.98	(188)
IF RELIANT	1,860,000	$ 5.96	(690)
IF TETCO STX	870,000	$ 6.76	-
NYMEX Henry Hub	2,130,000	$ 6.72	(228)
All gas swap contracts	32,880,000		$ 53,400

Gas Collars				
Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at June 30, 2009 Asset/(Liability)
	(MMBtu)	(per MMBtu)	(per MMBtu)	(In thousands)
Third quarter 2009				
IF CIG	600,000	$ 4.75	$ 8.82	$ 1,190
IF HSC	210,000	$ 5.57	$ 9.49	377
IF PEPL	1,385,000	$ 5.30	$ 9.25	2,853
NYMEX Henry Hub	90,000	$ 6.00	$ 10.35	192
Fourth quarter 2009				
IF CIG	600,000	$ 4.75	$ 8.82	746
IF HSC	210,000	$ 5.57	$ 9.49	284
IF PEPL	1,385,000	$ 5.30	$ 9.25	1,928
NYMEX Henry Hub	90,000	$ 6.00	$ 10.35	131
2010				
IF CIG	2,040,000	$ 4.85	$ 7.08	675
IF HSC	600,000	$ 5.57	$ 7.88	262
IF PEPL	4,945,000	$ 5.31	$ 7.61	2,096
NYMEX Henry Hub	240,000	$ 6.00	$ 8.38	133
2011				
IF CIG	1,800,000	$ 5.00	$ 6.32	(581)
IF HSC	480,000	$ 5.57	$ 6.77	(206)
IF PEPL	4,225,000	$ 5.31	$ 6.51	(1,821)
NYMEX Henry Hub	120,000	$ 6.00	$ 7.25	(36)
All gas collars	19,020,000			$ 8,223

Natural Gas Liquid Contracts

Natural Gas Liquid Swaps			
Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at June 30, 2009 Asset
	(Bbls)	(per Bbl)	(In thousands)
Third quarter 2009	217,000	$ 41.46	$ 1,710
Fourth quarter 2009	70,000	$ 45.95	872
2010	140,000	$ 49.59	2,403
2011	20,000	$ 49.01	300

All natural gas liquid swaps	447,000	$ 5,285

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 $275.0 million of floating-rate debt outstanding as of June 30, 2009. Our fixed-rate debt outstanding, net of debt discount, at this same date was $262.7 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 June 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. 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 this Quarterly Report on 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

  - 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 gas sales as a result of commodity price risk management activities
- 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
- 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

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, except as follows:

Proposed legislation to eliminate or reduce certain federal income tax incentives and deductions available to oil and gas exploration and production companies could, if enacted into law, have a material adverse effect on our results of operations and cash flows.

On April 23, 2009, the "Oil Industry Tax Break Repeal Act of 2009" was introduced in the U.S. Senate. This bill proposes amendments to the Internal Revenue Code of 1986 to eliminate or reduce certain federal income tax incentives and deductions currently available to oil and gas exploration and production companies. The proposed amendments include the elimination or reduction of current deductions for intangible drilling and development costs, percentage depletion allowances, and the manufacturing deduction for oil and gas properties. If some or all of these provisions are enacted into law, our effective tax rate and current income tax expense will increase, potentially significantly, which would reduce cash flows from operating activities and in turn reduce cash available for drilling and other exploration and development activities.

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

(c) The following table provides information about purchases by the Company or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the fiscal quarter ended June 30, 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)
04/01/09 –04/30/09	253	$ 17.65	-0-	3,072,184
05/01/09 – 05/31/09	88	$ 21.66	-0-	3,072,184
06/01/09 – 06/30/09	-	$ -	-0-	3,072,184
Total:	341	$ 18.69	-0-	3,072,184

(1) Includes 341 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 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

At the Company's annual stockholders' meeting on May 20, 2009, the stockholders elected management's current slate of directors and approved the two additional proposals described below. Each director was elected by a majority vote. The directors elected and the vote tabulation for each director were as follows:

Director	For	Withheld
Barbara M. Baumann	39,963,671	19,312,709
Anthony J. Best	55,919,083	3,357,297
Larry W. Bickle	55,714,283	3,562,097
William J. Gardiner	57,705,224	1,571,156
Julio M. Quintana	57,744,292	1,532,088
John M. Seidl	55,906,313	3,370,067
William D. Sullivan	57,484,287	1,792,093

The stockholders also approved the proposal to approve amendments to the 2006 Equity Incentive Compensation Plan, which as part of the amendments was renamed the Equity Incentive Compensation Plan (the "Plan"), to increase the number of shares available for issuance under the Plan and to change the fungible share counting provisions of the Plan to provide that "full share awards" under the Plan, which are awards other than stock options or stock appreciation rights, made after May 20, 2009, will be counted against the total share authorization limit as 1.43 shares for every one share issued.

For	37,889,664
Against	13,061,573
Abstain	952,531
Non Votes	7,372,612

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

For	57,504,724
Against	1,746,297
Abstain	25,359

ITEM 5. OTHER INFORMATION

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

Compensatory Arrangements of Certain Officers

On August 1, 2009, the Company granted awards (the "2009 Awards") of performance shares and restricted stock units ("RSUs") pursuant to the Company's long term incentive program ("LTIP") under the Company's Equity Incentive Compensation Plan, as amended and restated as of March 26, 2009 (the "Plan"), to various employees of the Company selected to participate in the LTIP, including the named executive officers of the Company listed below. The grants of the performance shares and RSUs were approved by the Compensation Committee of the Board of Directors of the Company. The following table sets forth the number of performance shares and RSUs that were granted to the Company's Chief Executive Officer, Chief Financial Officer, and the other executive officers of the Company for whom compensation disclosure was required in the Company's most recent proxy statement filed with the Securities and Exchange Commission.

Name and Position	Number of Performance Shares	Number of Restricted Stock Units
Anthony J. Best, President and Chief Executive Officer	52,500	17,500
A. Wade Pursell, Executive Vice President and Chief Financial Officer	28,500	9,500
Mark T. Solomon, Controller	5,437	1,813
Milam Randolph Pharo, Senior Vice President and General Counsel	10,875	3,625
Paul M. Veatch, Senior Vice President and Regional Manager	16,500	5,500
David J. Whitcomb, Vice President - Marketing	9,075	3,025

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

The performance criteria for the calculation of the actual number of shares to be issued upon settlement of the award is a combination of (i) the absolute measure of the total shareholder return ("TSR") over the performance period and the associated compound annual growth rate ("CAGR") of the Company for the performance period, and (ii) the relative measure of the Company's TSR and CAGR for the performance period compared with the TSR and CAGR of the Company's peer companies for the performance period, as reflected in a peer group index. The performance criteria are reflected in a payout matrix, which is used to determine the final number of shares, if any, to be awarded upon settlement of the performance shares to a 2009 Award recipient and is attached to the Performance Share and Restricted Stock Unit Award Agreement, a form of which is filed as Exhibit 10.5 hereto (the "Award Agreement").

The performance period for the performance shares began on July 1, 2009 and will end on June 30, 2012. The performance share awards granted in the 2009 will vest 1/7th on August 1, 2010, 2/7ths on August 1, 2011, and 4/7ths on August 1, 2012. Except as described below, shares issued upon settlement of vested performance shares will settle on or about August 1, 2012.

Each RSU represents the right to receive one share of the Company's common stock to be delivered upon settlement of the vested RSU. The RSUs will vest 1/7th on August 1, 2010, 2/7ths on August 1, 2011, and 4/7ths on August 1, 2012. Except as described below, for each vested portion of the RSUs, the settlement date will be the same date as the vesting date.

Except under certain circumstances described in the Award Agreement, if a 2009 Award recipient ceases to be an employee of the Company prior to the vesting of all of the performance shares or RSUs awarded in the 2009 Award, any remaining unvested performance shares or RSUs under the 2009 Award shall be forfeited.

The performance shares and RSUs of a 2009 Award recipient shall become fully vested in the event of a Change of Control Termination (as defined in the Award Agreement) with respect to such 2009 Award recipient's employment with the Company that occurs (i) within thirty months of a Change of Control (as defined in the Plan) of the Company and (ii) with respect to the performance shares, prior to the normal completion of vesting of the performance shares at the end of the performance period, or, with respect to the RSUs, prior to the normal completion of the vesting of the RSUs. In such case, with respect to the performance shares, the performance period used to determine the extent to which the performance criteria have been achieved shall be shortened to end as of the effective date of the Change of Control. Any shares that such recipient has earned under the 2009 Award shall be settled in shares or in cash of equivalent value within thirty days following the effective date of the Change of Control Termination.

The foregoing description of the Award Agreements does not purport to be complete and is qualified in its entirety by reference to the form of Award Agreement, a copy of which is filed as Exhibit 10.5 hereto and incorporated herein by reference. A form of the Performance Share and Restricted Stock Unit Award Notice to participants is filed as Exhibit 10.6 hereto and is incorporated herein by reference.

ITEM 6. EXHIBITS

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

Exhibit	Description
10.1	Third Amended and Restated Credit Agreement dated April 14, 2009 among St. Mary Land & Exploration Company, Wachovia Bank, National Association, as Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on April 20, 2009, and incorporated herein by reference)
10.2	Supplement and Amendment to Deed of Trust, Mortgage, Line of Credit Mortgage, Assignment, Security Agreement, Fixture Filing and Financing Statement for the benefit of Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 14, 2009 (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on April 20, 2009, and incorporated herein by reference)
10.3	Deed of Trust to Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 14, 2009 (filed as Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on April 20, 2009, and incorporated herein by reference)
10.4†	Equity Incentive Compensation Plan as Amended and Restated as of March 26, 2009 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on May 27, 2009)
10.5*†	St. Mary Land & Exploration Company Form of Performance Share and Restricted Stock Unit Award Agreement
10.6*†	St. Mary Land & Exploration Company Form of Performance Share and Restricted Stock Unit Award Notice
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
32.1**	Certification pursuant to U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes – Oxley Act of 2002

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* Filed with this report.

** Furnished with this report.

† Exhibit constitutes a management contract or compensatory plan or agreement.

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SIGNATURES

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

ST. MARY LAND & EXPLORATION COMPANY

August 4, 2009	By:	/s/ ANTHONY J. BEST Anthony J. Best President and Chief Executive Officer
August 4, 2009	By:	/s/ A. WADE PURSELL A. Wade Pursell Executive Vice President and Chief Financial Officer
August 4, 2009	By:	/s/ MARK T. SOLOMON Mark T. Solomon Controller