Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2010

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.)
1775 Sherman Street, Suite 1200, 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 x 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 (§232.405 of this chapter) 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 x	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 in Rule 12b-2 of the Exchange Act). Yes o No x

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date.

As of April 27, 2010 the registrant had 62,888,061 shares of common stock, $0.01 par value, outstanding.

Table of Contents

ST. MARY LAND & EXPLORATION COMPANY

INDEX

Table of Contents

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(In thousands, except share amounts)

	March 31, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 40,424	$ 10,649
Accounts receivable	129,302	116,136
Refundable income taxes	19,770	32,773
Prepaid expenses and other	9,772	14,259
Derivative asset	58,364	30,295
Deferred income taxes		4,934
Total current assets	257,632	209,046
Property and equipment (successful efforts method), at cost:		
Land	1,371	1,371
Proved oil and gas properties	2,889,235	2,797,341
Less - accumulated depletion, depreciation, and amortization	(1,116,733)	(1,053,518)
Unproved oil and gas properties, net of impairment allowance of $63,390 in 2010 and $66,570 in 2009	137,192	132,370
Wells in progress	89,676	65,771
Materials inventory, at lower of cost or market	25,094	24,467
Oil and gas properties held for sale less accumulated depletion, depreciation, and amortization	15,578	145,392
Other property and equipment, net of accumulated depreciation of $15,430 in 2010 and $14,550 in 2009	14,979	14,404
	2,056,392	2,127,598
Other noncurrent assets:		
Derivative asset	23,695	8,251
Restricted cash subject to Section 1031 Exchange	36,160	
Other noncurrent assets	14,435	16,041
Total other noncurrent assets	74,290	24,292
Total Assets	**$ 2,388,314**	**$ 2,360,936**
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 271,986	$ 236,242
Derivative liability	57,682	53,929
Deposit associated with oil and gas properties held for sale		6,500
Deferred income taxes	2,631	
Total current liabilities	332,299	296,671

Noncurrent liabilities:				
Long-term credit facility				188,000
Senior convertible notes, net of unamortized discount of $18,480 in 2010, and $20,598 in 2009		269,020		266,902
Asset retirement obligation		61,002		60,289
Asset retirement obligation associated with oil and gas properties held for sale		4,245		18,126
Net Profits Plan liability		143,019		170,291
Deferred income taxes		384,292		308,189
Derivative liability		46,823		65,499
Other noncurrent liabilities		14,023		13,399
Total noncurrent liabilities		922,424		1,090,695
Commitments and contingencies				
Stockholders equity:				
Common stock, $0.01 par value: authorized 200,000,000 shares; issued: 62,950,794 shares in 2010 and 62,899,122 shares in 2009; outstanding, net of treasury shares: 62,823,901 shares in 2010 and 62,772,229 shares in 2009		630		629
Additional paid-in capital		165,715		160,516
Treasury stock, at cost: 126,893 shares in 2010 and 2009		(1,179)		(1,204)
Retained earnings		974,620		851,583
Accumulated other comprehensive loss		(6,195)		(37,954)
Total stockholders equity		1,133,591		973,570
Total Liabilities and Stockholders Equity	**$**	**2,388,314**	**$**	**2,360,936**

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

Table of Contents

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

(In thousands, except per share amounts)

	For the Three Months Ended March 31, 2010	2009
Operating revenues and other income:		
Oil and gas production revenue	$ 212,887	$ 130,417
Realized oil and gas hedge gain	2,595	55,620
Gain (loss) on divestiture activity	120,978	(599)
Marketed gas system and other operating revenue	23,675	13,782
Total operating revenues and other income	360,135	199,220
Operating expenses:		
Oil and gas production expense	48,340	55,829
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	77,765	91,712
Exploration	13,898	13,598
Impairment of proved properties		147,049
Abandonment and impairment of unproved properties	904	3,902
Impairment of materials inventory		8,616
General and administrative	23,486	16,399
Change in Net Profits Plan liability	(27,272)	(23,291)
Marketed gas system expense	22,046	13,383
Unrealized derivative (gain) loss	(7,735)	1,846
Other expense	952	5,642
Total operating expenses	152,384	334,685
Income (loss) from operations	207,751	(135,465)
Nonoperating income (expense):		
Interest income	129	22
Interest expense	(6,787)	(6,096)
Income (loss) before income taxes	201,093	(141,539)
Income tax benefit (expense)	(74,915)	53,916
Net income (loss)	**$ 126,178**	**$ (87,623)**
Basic weighted-average common shares outstanding	62,792	62,335
Diluted weighted-average common shares outstanding	64,377	62,335
Basic net income (loss) per common share	**$ 2.01**	**$ (1.41)**
Diluted net income (loss) per common share	**$ 1.96**	**$ (1.41)**

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

Table of Contents

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, 2008	**62,465,572**	**$ 625**	**$ 141,283**	**(176,987)**	**$ (1,892)**	**$ 957,200**	**$ 65,293**	**$ 1,162,509**
Comprehensive loss, net of tax:								
Net loss						(99,370)		(99,370)
Change in derivative instrument fair value							(35,977)	(35,977)
Reclassification to earnings							(67,344)	(67,344)
Minimum pension liability adjustment							74	74
Total comprehensive loss								(202,617)
Cash dividends, $ 0.10 per share						(6,247)		(6,247)
Issuance of common stock under Employee Stock Purchase Plan	86,308	1	1,515					1,516
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	156,252	1	(1,951)					(1,950)
Sale of common stock, including income tax benefit of stock option exercises	189,740	2	1,592					1,594
Stock-based compensation expense	1,250		18,077	50,094	688			18,765
Balances, December 31, 2009	**62,899,122**	**$ 629**	**$ 160,516**	**(126,893)**	**$ (1,204)**	**$ 851,583**	**$ (37,954)**	**$ 973,570**
Comprehensive income, net of tax:								
Net Income						126,178		126,178
Change in derivative instrument fair value							33,702	33,702
Reclassification to earnings							(1,945)	(1,945)
Minimum pension liability adjustment							2	2
Total comprehensive income								157,937
Cash dividends, $ 0.05 per share						(3,141)		(3,141)
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	33,458	1	(647)					(646)
Sale of common stock, including income tax benefit of stock option exercises	18,214		268					268
Stock-based compensation expense			5,578		25			5,603

Balances, March 31, 2010	**62,950,794**	**$**	**630**	**$**	**165,715**	**(126,893)**	**$**	**(1,179)**	**$**	**974,620**	**$**	**(6,195)**	**$**	**1,133,591**

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

Table of Contents

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(In thousands)

	For the Three Months Ended March 31, 2010	2009
Cash flows from operating activities:		
Net income (loss)	$ 126,178	$ (87,623)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
(Gain) loss on divestiture activity	(120,978)	599
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	77,765	91,712
Exploratory dry hole expense	163	94
Impairment of proved properties		147,049
Abandonment and impairment of unproved properties	904	3,902
Impairment of materials inventory		8,616
Stock-based compensation expense	5,603	3,776
Change in Net Profits Plan liability	(27,272)	(23,291)
Unrealized derivative (gain) loss	(7,735)	1,846
Loss related to hurricanes		2,093
Amortization of debt discount and deferred financing costs	3,291	2,092
Deferred income taxes	64,608	(55,390)
Plugging and abandonment	(2,234)	(2,018)
Other	949	1,189
Changes in current assets and liabilities:		
Accounts receivable	(13,244)	43,703
Refundable income taxes	13,003	13,161
Prepaid expenses and other	1,489	(5,414)
Accounts payable and accrued expenses	31,402	(20,921)
Net cash provided by operating activities	**153,892**	**125,175**
Cash flows from investing activities:		
Proceeds from sale of oil and gas properties	239,247	1,063
Capital expenditures	(132,445)	(133,625)
Acquisition of oil and gas properties		(53)
Deposits to restricted cash	(36,160)	
Receipts from restricted cash		4,348
Other	(6,500)	
Net cash provided by (used in) investing activities	**64,142**	**(128,267)**
Cash flows from financing activities:		
Proceeds from credit facility	177,559	1,190,000
Repayment of credit facility	(365,559)	(1,191,000)
Proceeds from sale of common stock	268	172
Other	(527)	
Net cash used in financing activities	**(188,259)**	**(828)**
Net change in cash and cash equivalents	29,775	(3,920)
Cash and cash equivalents at beginning of period	10,649	6,131
Cash and cash equivalents at end of period	**$ 40,424**	**$ 2,211**

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

Table of Contents

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED) (Continued)

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

	For the Three Months Ended March 31, 2010	2009
	(In thousands)	
Cash paid for interest	$ 2,136	$ 1,509
Cash refunded for income taxes	$ (3,553)	$ (10,907)

Dividends of approximately $3.1 million have been declared by the Company s Board of Directors, but not paid, as of March 31, 2010.

As of March 31, 2010, and 2009, $104.6 million, and $76.4 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.

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

Table of Contents

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

March 31, 2010

Note 1 The Company and Business

St. Mary Land & Exploration Company (St. Mary or the Company) is an independent energy company engaged in the exploration, exploitation, development, acquisition, and production of natural gas and crude oil. The Company s operations are conducted entirely in the continental United States.

Note 2 Basis of Presentation and Significant Accounting Policies

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements of St. Mary have been prepared in accordance with accounting principles generally accepted in the United States for interim financial information and the instructions to Form 10-Q and Regulation S-X. They do not include all information and notes required by generally accepted accounting principles 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, 2009, (the 2009 Form 10-K). In the opinion of management, all adjustments, consisting of normal recurring accruals that are considered necessary for a fair presentation of the interim financial information, have been included. Operating results for the periods presented are not necessarily indicative of expected results for the full year. In connection with the preparation of the condensed consolidated financial statements of St. Mary, the Company evaluated subsequent events after the balance sheet date of March 31, 2010, through the filing of this report.

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 2009 Form 10-K , and are supplemented throughout the notes to consolidated financial statements in this report. It is suggested that these condensed consolidated financial statements be read in conjunction with the consolidated financial statements and notes included in the 2009 Form 10-K.

Note 3 Divestitures and Assets Held for Sale

Legacy Divestiture

In February 2010 the Company completed the divestiture of certain non-strategic oil properties located in Wyoming to Legacy Reserves Operating LP, a wholly-owned subsidiary of Legacy Reserves LP (Legacy). The transaction has an effective date of November 1, 2009. Total cash received, before commission costs and Net Profits Interest Bonus Plan (Net Profits Plan) payments, was $125.2 million, of which $6.5 million was received as a deposit in December 2009. The final sale price is subject to normal post-closing adjustments and is expected to be finalized during the second half of 2010. The estimated gain on sale related to the divestiture is approximately $65.1 million and may be impacted by the forthcoming post-closing adjustments mentioned above. The Company determined that the sale does not qualify for discontinued operations accounting under Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 205, Presentation of Financial Statements (ASC Topic 205). A portion of the transaction was structured to qualify as a like-kind exchange under Section 1031 of the Internal Revenue Code of 1986, as amended.

Table of Contents

Sequel Divestiture

In March 2010 the Company completed the divestiture of certain non-strategic oil properties located in North Dakota to Sequel Energy Partners, LP, Bakken Energy Partners, LLC, and Three Forks Energy Partners (collectively referred to as Sequel). The transaction has an effective date of November 1, 2009. Total cash received, before commission costs and Net Profits Plan payments, was $126.9 million. The final sale price is subject to normal post-closing adjustments and is expected to be finalized during the second half of 2010. The estimated gain on sale related to the divestiture is approximately $50.8 million and may be impacted by the forthcoming post-closing adjustments mentioned above. The Company determined that the sale does not qualify for discontinued operations accounting under ASC Topic 205. A portion of the transaction was structured to qualify as a like-kind exchange under Section 1031 of the Internal Revenue Code of 1986, as amended.

Assets Held for Sale

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

As of March 31, 2010, the accompanying consolidated balance sheets present $15.6 million in book value of assets held for sale, net of accumulated depletion, depreciation, and amortization. The corresponding asset retirement obligation liability of $4.2 million is also separately presented. The Company determined that these planned asset sales do not qualify for discontinued operations accounting under ASC Topic 205. Subsequent to March 31, 2010, the Company has either divested of or entered into an agreement to sell the $15.6 million in book value of non-core properties that were classified as held for sale at March 31, 2010.

Note 4 Income Taxes

Income tax expense (benefit) for the three-month periods ended March 31, 2010, and 2009, differs from the amounts that would be provided by applying the statutory U.S. federal income tax rate to income (loss) before income taxes as a result of the estimated effect of the domestic production activities deduction, percentage depletion, the effect of state income taxes, and other permanent differences. The provision for income taxes consists of the following:

	For the Three Months Ended March 31, 2010	2009
	(In thousands)	
Current portion of income tax expense:		
Federal	$ 9,975	$ 1,083
State	332	390
Deferred portion of income tax expense (benefit)	64,608	(55,389)
Total income tax expense (benefit)	$ 74,915	$ (53,916)

Effective tax rate	37.3%	38.1%

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. Non-core asset sales through

Table of Contents

March 31, 2010 and the Company s anticipated drilling budget for the rest of 2010 are having an offsetting rate impact when compared to the low commodity price environment in the first quarter of 2009 and 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 tax differences affect the presented periods differently.

The Company and 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 these tax authorities for years before 2006. In late 2009 the Internal Revenue Service announced a National Research Program (NRP) study of employment tax compliance that it would begin audits of randomly selected taxpayers to collect data for. During the first quarter of 2010, the Internal Revenue Service initiated an audit of St. Mary for the 2006 tax year directed toward compensation which the Company believes is related to the NRP. The Company s 2005 income tax audit was concluded in the first quarter of 2009 with a refund to the Company of $278,000 plus interest of $41,000. There was no change to the provision for income tax expense as a result of the 2005 examination. At March 31, 2010, the Company is awaiting a $5.5 million refund related to its 2006 tax year as a result of a net operating loss carry back from the Company s 2008 tax year. This refund claim has been combined with the compensation audit discussed above and cannot be received until the audit is completed and submitted to the Joint Committee on Taxation for review. The Company s remaining refundable income tax balance reflects its intention to utilize the extended carry back period for a taxable net operating loss generated for the 2009 tax year.

Note 5 Earnings per Share

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

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

The Company s 3.50% Senior Convertible Notes have a net-share settlement right whereby each $1,000 principal amount of notes may be surrendered for conversion to cash in an amount equal to the principal amount and, if applicable, shares of common stock or cash or any combination of common stock and cash for the amount of conversion value 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 periods ended March 31, 2010, and 2009.

The Company s PSAs have a three-year performance period. The PSAs represent the right to receive, upon settlement of the PSAs after the completion of the three-year performance period, a number of shares of the Company s common stock that may be from zero to two times the number of PSAs granted on the award date, depending on the extent to which the Company s performance criteria have been achieved and the extent to which the PSAs have vested. The performance criteria for the PSAs are based on a combination of the Company s total shareholder return (TSR) for the performance period and the relative performance of the Company s TSR compared with the TSR of certain peer companies for the performance period. The number of potentially dilutive shares related to PSAs is based on the number of

Table of Contents

shares, if any, which would be issuable at the end of the respective reporting period, assuming that date was the end of the contingency period. For additional discussion on PSAs, please see Note 7 Compensation Plans - *Performance Share Awards Under the Equity Incentive Compensation Plan*.

The treasury stock method is used to measure the dilutive impact of stock options, RSUs, 3.50% Senior Convertible Notes, and PSAs. In accordance with FASB ASC Topic 260, Earnings Per Share when there is a loss from continuing operations, all potentially dilutive shares will be anti-dilutive. There were no dilutive shares for the three-month period ended March 31, 2009, because the Company recorded a loss for that period. Unvested RSUs, contingent PSAs, and in-the-money options had a dilutive impact for the three-month period ended March 31, 2010, 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 March 31,	
	2010	**2009**
Net income (loss)	$ 126,178	$ (87,623)
Basic weighted-average common shares outstanding	62,792	62,335
Add: dilutive effect of stock options, unvested RSUs, and contingent PSAs	1,585	
Add: dilutive effect of 3.50% senior convertible notes		
Diluted weighted-average common shares outstanding	64,377	62,335
Basic net income (loss) per common share	$ 2.01	$ (1.41)
Diluted net income (loss) per common share	$ 1.96	$ (1.41)

Table of Contents

Note 6 Commitments and Contingencies

In February 2010 the Company entered into an agreement whereby it is subject to a certain natural gas gathering through-put contract that requires a minimum volume delivery of 100 Bcf by the end of the ten year contract term. The Company will be required to pay $0.18 per Mcf for any shortfall in delivering the minimum volume. At the current time, the Company does not have proved developed reserves in the service area to fulfill this contractual commitment, but fully intends to develop proved undeveloped reserves that will exceed the through-put commitment. The pipeline volume commitments associated with this agreement for the next five years and thereafter are presented below:

Years Ending December 31,	Committed Volumes (In Bcf)		Undiscounted Cash Outflows (In thousands)
2010	3.0	$	540
2011	6.0		1,080
2012	6.0		1,080
2013	10.0		1,800
2014	10.0		1,800
Thereafter	65.0		11,700
Total	100.0	$	18,000

Note 7 Compensation Plans

Cash Bonus Plan

During the first quarter of 2010 and 2009, the Company paid $7.7 million and $6.0 million for cash bonuses earned in the 2009 and 2008 performance years, respectively. Within the general and administrative expense and exploration expense line items in the accompanying consolidated statements of operations was $3.1 million and $2.4 million of cash bonus expense related to the specific performance year for the three-month periods ended March 31, 2010, and 2009, respectively.

Performance Share Awards Under the Equity Incentive Compensation Plan

Total stock-based compensation expense related to PSAs for the three-month periods ended March 31, 2010, and 2009, was $3.6 million and $1.4 million, respectively. As of March 31, 2010, there was $19.7 million of total unrecognized compensation expense related to unvested PSAs. The unrecognized compensation expense will be amortized through 2012.

A summary of the status and activity of PSAs for the three-month period ended March 31, 2010, is presented in the following table:

	PSAs		Weighted-Average Grant-Date Fair Value
Non-vested, at January 1, 2010	1,069,090	$	32.52
Granted		$	
Vested	(5,362)	$	30.73
Forfeited	(34,718)	$	31.27
Non-vested, at March 31, 2010	1,029,010	$	32.57

Table of Contents

Restricted Stock Unit Incentive Program Under the Equity Incentive Compensation Plan

Total RSU compensation expense for the three-month periods ended March 31, 2010, and 2009, was $1.8 million and $2.1 million, respectively. As of March 31, 2010, there was $7.5 million of total unrecognized compensation expense related to unvested RSU awards. The unrecognized compensation expense will be amortized through 2012.

During the first three months of 2010, the Company settled 49,558 RSUs, which relate to awards granted in 2008 and 2007, through the issuance of shares of the Company s common stock in accordance with the 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 33,458 shares of common stock associated with these grants. The remaining 16,100 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 RSUs for the three-month period ended March 31, 2010, is presented in the following table:

	RSUs		**Weighted-Average Grant-Date Fair Value**
Non-vested, at January 1, 2010	407,123	$	34.67
Granted		$	
Vested	(48,725)	$	36.30
Forfeited	(11,398)	$	39.43
Non-vested, at March 31, 2010	347,000	$	34.28

As of March 31, 2010, a total of 347,400 RSUs were outstanding, of which 400 were vested.

Stock Option Grants Under Prior Stock Option Plans

The following table summarizes the three-month activity for stock options outstanding as of March 31, 2010:

	Options		**Weighted-Average Exercise Price**	**Weighted Average Remaining Contractual Term (In years)**	**Aggregate Intrinsic Value (In thousands)**
Outstanding, at January 1, 2010	1,274,920	$	13.31		
Exercised	(18,214)	$	14.71		

Forfeited		$					
Outstanding, end of period	1,256,706	$	13.29	2.7	$	27,045
Vested, or expect to vest, at March 31, 2010	1,256,706	$	13.29	2.7	$	27,045
Exercisable, end of period	1,256,706	$	13.29	2.7	$	27,045

As of March 31, 2010, there was no unrecognized compensation cost related to unvested stock option awards.

Table of Contents

Net Profits Plan

Under the Company s Net Profits Plan, all oil and gas wells that were completed or acquired during each plan year prior to 2008 were designated within a specific pool for that year. Key employees become entitled to payments under the Net Profits Plan after the Company has received net cash flows returning 100 percent of all costs associated with that pool. Thereafter, ten percent of future net cash flows generated by the pool are allocated among the participants and distributed at least annually. The portion of net cash flows from the pool to be allocated among the participants increases to 20 percent after the Company has recovered both 200 percent of the total costs for the pool, and payments made under the Net Profits Plan at the ten percent level. The 2007 Net Profits Plan pool was the last pool established by the Company.

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

	For the Three Months Ended March 31,	
	2010	2009
	(In thousands)	
General and administrative expense	$ 6,934	$ 3,233
Exploration expense	591	406
Total	$ 7,525	$ 3,639

Additionally, the Company accrued cash payments under the Net Profits Plan of $18.2 million for the three-month period ended March 31, 2010, as a result of sales proceeds from the Legacy and Sequel divestitures. The cash payments are accounted for as a reduction of proceeds, which reduced the gain (loss) on divestiture activity in the accompanying consolidated statements of operations. There were no cash payments made under the Net Profits Plan as a result of divestitures that occurred during the first quarter 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 consolidated statements of operations. The change in the estimated liability is recorded as a non-cash expense or benefit in the current period. The amount recorded as an expense or benefit associated with the change in the estimated liability is not allocated to general and administrative expense or exploration expense because it is associated with the future net cash flows from oil and gas properties in the respective pools rather than results being realized through current period production. The table below presents the estimated allocation of the change in the liability if the Company did allocate the adjustment to these specific functional line items based on the current allocation of actual distributions made by the Company. As time progresses, less of the distributions relate to prospective exploration efforts as more of the distributions are made to participants that have terminated employment and do not provide ongoing exploration support to the Company.

	For the Three Months Ended March 31,	
	2010	2009
	(In thousands)	
General and administrative benefit	$ 26,645	$ 20,694
Exploration benefit	627	2,597
Total benefit	$ 27,272	$ 23,291

14

Table of Contents

Note 8 Pension Benefits

Pension Plans

The Company has a non-contributory pension plan covering substantially all employees who meet age and service requirements (the Qualified Pension Plan). The Company also has a supplemental non-contributory pension plan covering certain management employees (the Nonqualified Pension Plan).

Components of Net Periodic Benefit Cost for Both Plans

The following table presents the total components of the net periodic cost for both the Qualified Pension Plan and the Nonqualified Pension Plan:

	For the Three Months Ended March 31, 2010	2009
	(In thousands)	
Service cost	$ 848	$ 625
Interest cost	280	234
Expected return on plan assets	(159)	(108)
Amortization of net actuarial loss	91	93
Net periodic benefit cost	$ 1,060	$ 844

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 not required to make a minimum contribution to the pension plans in 2010.

Note 9 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

Table of Contents

federal or state regulators enact new requirements regarding the abandonment of wells. The asset retirement obligation is considered settled when the well has been plugged and abandoned or divested.

A reconciliation of the Company s asset retirement obligation liability is as follows:

		For the Three Months Ended March 31, 2010 (In thousands)
Beginning asset retirement obligation	$	102,080
Liabilities incurred		625
Liabilities settled		(17,010)
Accretion expense		1,511
Revision to estimated cash flow		
Ending asset retirement obligation	$	87,206

As of March 31, 2010, the Company had $4.2 million of asset retirement obligation associated with the oil and gas properties held for sale included in a separate line item on the Company s accompanying consolidated balance sheets. Additionally, as of March 31, 2010, accounts payable and accrued expenses contained $22.0 million related to the Company s current asset retirement obligation liability associated with the estimated retirement of some of the Company s offshore platforms.

Note 10 Derivative Financial Instruments

Oil, Natural Gas and NGL Commodity Hedges

To mitigate a portion of the potential exposure to adverse market changes in oil and gas prices and the associated impact on cash flows, the Company has entered into various derivative contracts. The Company s derivative contracts in place include swap and collar arrangements for oil, natural gas, and natural gas liquids (NGLs). As of March 31, 2010, the Company has hedge contracts in place through the end of 2012 for a total of approximately 6 million Bbls of anticipated crude oil production, 54 million MMBtu of anticipated natural gas production, and 1 million Bbls of anticipated natural gas liquids production. As of April 27, 2010, the Company has hedge contracts in place through the first quarter of 2013 for a total of approximately 6 million Bbls of anticipated crude oil production, 54 million MMBtu of anticipated natural gas production, and 2 million Bbls of anticipated natural gas liquids production.

The Company attempts to qualify its oil, natural gas, and NGL derivative instruments as cash flow hedges for accounting purposes under FASB ASC Topic 815, Derivatives and Hedging (ASC Topic 815). The Company formally documents all relationships between the derivative instruments and the hedged production, as well as the Company s risk management objective and strategy for the particular derivative contracts. This process includes linking all derivatives that are designated as cash flow hedges to the specific forecasted sale of oil, natural gas or NGLs. 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 March 31, 2010, all oil, natural gas, and NGL derivative instruments qualified as cash flow hedges for accounting purposes. The Company anticipates

Table of Contents

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, natural gas, and NGL hedges are measured at fair value and are included in the accompanying consolidated balance sheets as derivative assets and liabilities. The Company derives internal valuation estimates taking into consideration the counterparties credit worthiness, the Company s credit worthiness, and the time value of money. Those internal valuations are then compared to the counterparties mark-to-market statements. The consideration of the factors results in an estimated exit-price for each derivative asset or liability under a market place participant s view. Management believes that this approach provides a reasonable, non-biased, verifiable, and consistent methodology for valuing commodity derivative instruments. The derivative instruments utilized by the Company are not considered by management to be complex, structured, or illiquid. The oil, natural gas, and NGL derivative markets are highly active. The fair value of oil, natural gas, and NGL derivative contracts designated and qualifying as cash flow hedges under ASC Topic 815 was a net liability of $22.4 million and $80.9 million at March 31, 2010, and December 31, 2009, 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 March 31, 2010**	**Fair Value at December 31, 2009**
		(In thousands)	
Derivative assets designated as cash flow hedges:			
Oil, natural gas, and NGL commodity	Current assets	$ 58,364	$ 30,295
Oil, natural gas, and NGL commodity	Other noncurrent assets	23,695	8,251
Total derivative assets designated as cash flow hedges under ASC Topic 815		$ 82,059	$ 38,546
Derivative liabilities designated as cash flow hedges:			
Oil, natural gas, and NGL commodity	Current liabilities	$ (57,682)	$ (53,929)
Oil, natural gas, and NGL commodity	Noncurrent liabilities	(46,823)	(65,499)
Total derivative liabilities designated as cash flow hedges under ASC Topic 815		$ (104,505)	$ (119,428)

Realized gains or losses from the settlement of oil, natural gas, and NGL derivative contracts are reported in the total operating revenues section of the accompanying consolidated statements of operations. The Company realized a net gain of $2.6 million and a net gain of $55.6 million from its oil, natural gas, and NGL derivative contracts for the three month periods ended March 31, 2010, and 2009, respectively.

After-tax changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributed to the hedged risk, are recorded in accumulated other comprehensive income in the accompanying consolidated balance sheets until the hedged item is realized in earnings upon the sale of the associated hedged production. As of March 31, 2010, the amount of unrealized loss net of deferred income taxes to be reclassified from accumulated other comprehensive income to realized oil and gas hedge gain (loss) in the Company s accompanying consolidated statements of operations in the next twelve months is $6.5 million.

The Company seeks to minimize ineffectiveness by entering into oil derivative contracts indexed to the New York Mercantile Exchange West Texas Intermediate (NYMEX WTI) index, natural gas derivative contracts indexed to regional index prices associated with pipelines in proximity to the

Table of Contents

Company s areas of production, and NGL derivative contracts indexed to Oil Price Information Service Mont Belvieu. As the Company s derivative contracts contain the same index as the Company s sales contracts, this results in derivative contracts that are highly correlated with the underlying hedged item.

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

	Derivatives Qualifying as Cash Flow Hedges	For the Three Months Ended March 31, 2010 (In thousands)	2009
Amount of (gain) loss on derivatives recognized in OCI during the period (effective portion)	Commodity hedges	$ (33,702)	$ (14,148)
Amount of (gain) loss reclassified from AOCI to realized oil and gas hedge gain (loss) (effective portion)	Commodity hedges	$ (1,945)	$ (26,550)

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

Derivatives Qualifying as Cash Flow Hedges	Classification of (Gain) Loss Recognized in Earnings	(Gain) Loss Recognized in Earnings (Ineffective Portion) For the Three Months Ended March 31, 2010 (In thousands)	2009
Commodity hedges	Unrealized derivative (gain) loss	$ (7,735)	$ 1,846

Credit Related Contingent Features

As of March 31, 2010, only one of the Company s hedge counterparties was not a member of the Company s credit facility bank syndicate. Member banks are secured by the Company s oil and gas assets, and therefore 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 the one non-member bank, the amount of collateral, if any, that the Company is required to post depends on a number of financial metrics that are calculated quarterly. No collateral was posted as of March 31, 2010, or April 27, 2010.

18

Table of Contents

Convertible Note Derivative Instruments

The contingent interest provision of the 3.50% Senior Convertible Notes is a derivative instrument. As of March 31, 2010, and December 31, 2009, the value of this derivative was determined to be immaterial.

Note 11 Fair Value Measurements

The Company follows the authoritative accounting guidance under FASB ASC Topic 820, Fair Value Measurements and Disclosures (ASC Topic 820) for all assets and liabilities measured at fair value. ASC Topic 820 establishes a framework for measuring fair value and requires enhanced disclosures about fair value measurements. ASC Topic 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The topic establishes market or observable inputs as the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The topic establishes a hierarchy for grouping these assets and liabilities based on the significance level of the following inputs:

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

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

- Level 3 Significant inputs to the valuation model are unobservable

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 March 31, 2010:

	Level 1	Level 2 (In thousands)	Level 3
Assets:			
Derivatives	$	$ 82,059	$
Liabilities:			
Derivatives	$	$ 104,505	$
Net Profits Plan	$	$	$ 143,019

There were no nonfinancial assets or liabilities measured at fair value on a nonrecurring basis at March 31, 2010.

Table of Contents

The following is a listing of the Company s assets and liabilities that are measured at fair value and where they are classified within the hierarchy as of December 31, 2009:

	Level 1	Level 2 (In thousands)	Level 3
Assets:			
Derivatives(a)	$	$ 38,546	$
Proved oil and gas properties(b)	$	$	$ 11,740
Materials inventory(b)	$	$ 13,882	$
Liabilities:			
Derivatives(a)	$	$ 119,428	$
Net Profits Plan(a)	$	$	$ 170,291

(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.

Both financial and non-financial 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 derives internal valuation estimates taking into consideration the counterparties credit ratings, the Company s credit rating, and the time value of money. These valuations are then compared to the respective counterparties mark-to-market statements. The considered factors result in an estimated exit-price that management believes provides a reasonable and consistent methodology for valuing derivative instruments.

Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. However, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. The Company monitors the credit ratings of its counterparties and may ask counterparties to post collateral if their ratings deteriorate. In some instances the Company will attempt to novate the trade to a more stable counterparty.

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

The methods described above may result in a fair value estimate that may not be indicative of net realizable value or may not be reflective of future fair values and cash flows. While the Company believes that the valuation methods utilized are appropriate and consistent with the requirements of ASC Topic 820 and with other marketplace participants, the Company recognizes that third parties may use different methodologies or assumptions to determine the fair value of certain financial instruments that could result in a different estimate of fair value at the reporting date.

Table of Contents

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 and their impact on net cash flows and the amount of the Net Profits Plan liability. Generally, higher commodity prices result in a larger Net Profits Plan liability and vice versa.

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 Company continually evaluates the assumptions used in this calculation in order to consider the current market environment for oil and gas prices, costs, discount rates, and overall market conditions. The Net Profits Plan liability was determined using price assumptions that were computed using five one-year strip prices with the fifth year s pricing being carried out indefinitely. The average price was adjusted to include the effects of hedge prices for the percentage of forecasted production hedged in the relevant periods. The 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.

Table of Contents

If the commodity prices used in the calculation changed by five percent, the liability recorded at March 31, 2010, would differ by approximately $11 million. A one percentage point change in the discount rate would change the liability by approximately $7 million. Actual cash payments to be made to participants in future periods are dependent on realized actual production, realized commodity prices, and costs associated with the properties in each individual pool of the Net Profits Plan. Consequently, actual cash payments are inherently different from the amounts estimated. No published market quotes exist on which to base the Company s estimate of fair value of the Net Profits Plan liability. As such, the recorded fair value is based entirely on management estimates that are described within this footnote. While some inputs to the Company s calculation of fair value on 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 Months Ended March 31, 2010	2009
	(In thousands)	
Beginning balance	$ 170,291	$ 177,366
Net increase (decrease) in liability (a)	(1,536)	(19,653)
Net settlements (a)(b)	(25,736)	(3,638)
Transfers in (out) of Level 3		
Ending balance	$ 143,019	$ 154,075

(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 and include $18.2 million of cash payments related to the Legacy and Sequel divestitures.

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 $286.8 million and $290.0 million as of March 31, 2010, and December 31, 2009, respectively.

Proved Oil and Gas Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value if the sum of the expected undiscounted future cash flows is less than net book value pursuant to ASC Topic 360. The Company uses Level 3 inputs and the income valuation technique, which converts future amounts to a single present value amount, to measure the fair value of proved properties through an application of discount rates and price forecasts selected by the Company s management. The discount rate is a rate that management believes is representative of current market conditions and includes the following factors: estimates 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.

In accordance with ASC Topic 820, of the $2.1 billion worth of long-lived assets, excluding materials inventory, $11.7 million were measured at fair value at December 31, 2009. There were no long-lived assets measured at fair value within the accompanying consolidated balance sheets at March 31, 2010.

Table of Contents

Asset Retirement Obligations

The Company estimates asset retirement obligations pursuant to the provisions of FASB ASC Topic 410, Asset Retirement and Environmental Obligations. 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 March 31, 2010.

Refer to Note 10 Derivative Financial Instruments and Note 9 Asset Retirement Obligations for more information regarding the Company s hedging instruments and asset retirement obligations.

Note 12 Recent Accounting Pronouncements

The Company partially adopted FASB ASC Update 2010-06, Fair Value Measurements and Disclosures (ASC Update 2010-06) that requires additional disclosures surrounding transfers between Levels 1 and 2, inputs and valuation techniques used to value Level 2 and 3 measurements, and push down of previously prescribed fair value disclosures to each class of asset and liability for Levels 1, 2, and 3. These disclosures were effective for the Company for the quarter ended March 31, 2010. The partial adoption of this pronouncement did not have a material impact on the Company s consolidated financial statements.

ASC Update 2010-06 also requires that purchases, sales, issuances, and settlements for Level 3 measurements be disclosed. This portion of the new authoritative guidance is effective for interim and annual reporting periods beginning after December 15, 2010. The Company will apply this new authoritative guidance in the Company s March 31, 2011, Quarterly Report on Form 10-Q. The adoption of ASC Update 2010-06 will not have a material impact on the Company s financial statements.

The Company adopted FASB ASC Update 2010-09, Amendments to Certain Recognition and Disclosure Requirements, that removes the requirement for SEC filers to disclose the date through which an entity has evaluated subsequent events. However, the date-disclosure exemption does not relieve management of an SEC filer from its responsibility to evaluate subsequent events through the date on which financial statements are issued. This authoritative guidance was effective upon issuance on February 24, 2010. The adoption of this pronouncement did not have a material impact on the Company s consolidated financial statements.

Note 13 Subsequent Event

On April 29, 2010, the Company entered into a Carry and Earning Agreement (the CEA), which effectively provides for a third party to earn 95 percent of St. Mary s interest in approximately 8,400 net acres in a portion of the Company s East Texas Haynesville shale acreage, as well as an interest in several wells currently drilling, and five percent of St. Mary s interest in approximately 23,400 net acres in a separate portion of the Company s Haynesville acreage in East Texas. In exchange for these interests, the third party has agreed to invest $91.3 million to fund the drilling and completion costs of horizontal wells in the portion of the leases where the Company is retaining 95 percent of its current interest. Of this, $86.7 million represents St. Mary s carried drilling and completion costs, being 95 percent of the total amount invested by the third party. The Company received an initial payment of $45.6 million on April 29, 2010, and the CEA provides that the Company will receive the balance of the committed funds less any adjustments allowed under the CEA for title defects within 30 days of the completion of the fourth commitment well. Once St. Mary has completed the expenditure of the total carry amount, the parties will share all costs of operations within the area of joint ownership in accordance with their respective ownership interests.

Table of Contents

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.

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, natural gas liquids, and crude oil in the continental United States. Generally, we generate nearly all our revenues and cash flows from the sale of produced natural gas and crude oil. However, in 2010 we have generated significant revenues from the sale of non-strategic oil and gas properties. Our oil and gas reserves and operations are concentrated primarily in the Rocky Mountain Williston Basin; the Mid-Continent Anadarko and Arkoma basins; the Permian Basin; the productive formations of East Texas and North Louisiana; north central Pennsylvania; the Maverick Basin in South Texas; and the onshore Gulf Coast. We have developed a balanced and diverse portfolio of proved reserves, development drilling opportunities, and 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 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 more on capturing upside from potential resource plays early and at a lower cost. We believe this shift allows for more stable and predictable production and proved reserves growth. Going forward, we will focus on continuing to acquire significant leasehold positions at reasonable costs in existing and emerging resource plays in North America.

Financial Standing and Liquidity

On March 17, 2010, the borrowing base on our credit facility was redetermined and maintained by our bank group at a value of $900 million despite the divestiture of non-strategic Rocky Mountain oil properties during the quarter. The commitment amount of the bank group remained unchanged at $678 million. At the end of the first quarter 2010 and through the filing date, we had no outstanding borrowings under the revolving credit facility. We have no debt maturities until 2012, at which time our credit facility matures and our outstanding convertible notes can be put to us. Given our debt levels, credit standing, and relationships with the participants in our bank group, we believe we will be able to enter into an amended credit facility before our current credit facility matures in 2012. We also believe our convertible notes could be put to us in 2012, at which time we have the option of settling with cash and/or common stock. The condition of the capital markets has improved significantly since last year and therefore we believe we could access capital through the public markets, if necessary, to redeem these notes.

We expect our generated cash flow from operations in 2010 plus proceeds from our Rocky Mountain oil and other non-core asset divestitures will fund our capital budget for 2010. Accordingly, we do not anticipate accessing the equity or public debt markets for the remainder of 2010. Given the size of and commitments associated with our existing inventory of potential drilling projects, our needs for capital could increase significantly in 2011 and beyond. As a result, we may consider accessing the capital markets, as well as other alternatives, as we determine how to best fund our capital programs. We continue to believe we have adequate liquidity available as discussed below under the caption Overview of Liquidity and Capital Resources.

Table of Contents

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. We account for our natural gas sales as if they occurred at the wellhead and accordingly we do not present a separate production stream for natural gas liquids that are processed from our production. We receive value for the NGL content in our natural gas stream, which can result in us realizing a higher per unit price for our reported gas production. 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 first quarters of 2010 and 2009 and the fourth quarter of 2009:

	For the Three Months Ended		
	March 31, 2010	**December 31, 2009**	**March 31, 2009**
Crude Oil (per Bbl):			
Average NYMEX price	$ 78.84	$ 76.03	$ 43.18
Realized price, before the effects of hedging	$ 72.73	$ 68.98	$ 34.40
Net realized price, including the effects of hedging	$ 66.96	$ 64.43	$ 44.16
Natural Gas (per Mcf):			
Average NYMEX price	$ 5.09	$ 4.37	$ 4.56
Realized price, before the effects of hedging	$ 6.15	$ 4.88	$ 4.00
Net realized price, including the effects of hedging	$ 6.84	$ 6.07	$ 6.14

We expect future prices for oil, NGLs, and natural gas to be volatile. In addition to supply and demand fundamentals, the relative strength of the U.S. Dollar will likely continue to impact crude prices. Generally, NGL prices historically have trended and correlated with the price for crude oil. The supply of NGLs is expected to grow in the near term as a result of a number of industry participants targeting projects that produce these products and this could negatively impact future pricing.   Future natural gas prices are facing downward pressure as a result of a perceived supply overhang resulting from increased levels of drilling activity across the country, as well as slow demand recovery due to the recession. The 12-month strip prices for NYMEX WTI crude oil and NYMEX Henry Hub gas as of March 31, 2010, were $85.12 per Bbl and $4.64 per MMBTU, respectively; comparable prices as of April 27, 2010, were $88.40 per Bbl and $4.96 per MMBTU, respectively.

While changes in quoted NYMEX oil and natural gas prices are generally used as a basis for comparison within our industry, the price we receive for oil and natural gas is affected by quality, energy content, location, and transportation differentials for these products. We refer to this price as our realized price, which excludes the effects of hedging. Our realized price is further impacted by the results of our hedging arrangements that are settled in the respective periods. We refer to this price as our net realized price. For the three months ended March 31, 2010, our net natural gas price realization was positively impacted by $11.4 million of realized hedge settlements and our net oil price realization was negatively impacted by $8.8 million of realized hedge settlements.

Table of Contents

Hedging Activities

Hedging is an important part of our financial risk management program. We have a Board-authorized financial risk management policy that governs our practices related to hedging. The amount of production we hedge is driven by the amount of debt on our consolidated balance sheet and the level of capital commitments and long-term obligations we have in place. In the case of a significant acquisition of producing properties, we will consider hedging a portion of the acquired production in order to protect the economics assumed in the acquisition. With the hedges we have in place, we believe we have established a base cash flow stream for our future operations, and our use of collars for a portion of the hedges allows us to participate in upward movements in oil and gas prices while also setting a price floor for a portion of our production. Please see Note 10 Derivative Financial Instruments of Part I, Item 1 of this report for additional information regarding our oil and gas hedges, and see the caption, *Summary of Oil and Gas Production Hedges in Place,* later in this section.

We attempt to qualify our oil and gas derivative instruments as cash flow hedges for accounting purposes under ASC Topic 815. Changes in the value of our hedge positions are primarily reflected in our consolidated balance sheets. A portion of the change in the value of our hedge positions is recognized in our consolidated statements of operations due to hedges being partially ineffective. We recognized $7.7 million in non-cash derivative gain in the first quarter of 2010. This was primarily caused by decreases in the price of natural gas causing hedge liabilities to decrease, which in turn resulted in ineffectiveness gains.

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

First Quarter 2010 Highlights

Developments in emerging resource plays. During the first quarter, we saw a number of positive developments in many of our emerging resource plays as a result of our activity as well as the activity of industry peers. In the Eagle Ford shale, well results on our operated acreage in the quarter continued to be favorable. These results indicate that production from a significant portion of our acreage should contain condensate and rich gas. These results improve our net back pricing at current commodity prices. The consistent results we have seen across our acreage position are encouraging to us. On our joint venture acreage, our partner began to accelerate activity during the quarter. We participated in its nascent infrastructure development to service current and future development on the joint venture acreage. In the Haynesville shale, successful wells by offset operators around our acreage in East Texas continue to de-risk this play for us. We began drilling on this acreage in the first quarter. We had a couple of successful completions in the North Dakota portion of the Williston Basin during the quarter in the Bakken and Three Forks formations. In the Mayfield area of the Anadarko Basin in Oklahoma, we also began drilling our first horizontal Granite Wash well in the first quarter.

Shift toward oil-weighted projects. As a result of continued downward pressure on natural gas prices and strong oil prices, we focused our capital investment dollars toward oil-weighted projects starting in the third quarter of 2009. We continue to expect strong levels of future activity in our Permian and Rocky Mountain regions, as well as in projects with NGL-rich natural gas like the Eagle Ford shale, as a result of current commodity price levels.

Legacy Divestiture. On February 17, 2010, we closed on a divestiture of non-core properties in Wyoming to Legacy Reserves Operating LP. Total cash received, before commission costs and Net Profits Plan payments, was $125.2 million. The final sale price is subject to normal post-closing adjustments and is expected to be finalized during the second half of 2010. The estimated gain on sale of proved properties

Table of Contents

related to the divestiture is approximately $65.1 million and may be impacted by the forthcoming post-closing adjustments mentioned above. We diverted a portion of the proceeds from this divestiture to restricted cash and will attempt to use these funds in a tax deferral strategy under Section 1031 of the Internal Revenue Code.

Sequel Divestiture. On March 12, 2010, we completed the divestiture of certain non-strategic oil and gas properties located in North Dakota to Sequel Energy Partners, LP, Bakken Energy Partners, LLC, and Three Forks Energy Partners. Total cash received, before commission costs and Net Profits Plan payments, was $126.9 million. The final sale price is subject to normal post-closing adjustments and is expected to be finalized during the second half of 2010. The estimated gain on sale of proved properties related to the divestiture is approximately $50.8 million and may be impacted by the forthcoming post-closing adjustments mentioned above. We diverted a portion of the proceeds from this divestiture to restricted cash and will attempt to use these funds in a tax deferral strategy under Section 1031 of the Internal Revenue Code.

Financial and production results. We recorded net income for the quarter ended March 31, 2010, of $126.2 million or $1.96 per diluted share, which reflects a $121.0 million pre-tax gain on divestiture activity, compared to first quarter 2009 results of a net loss of $87.6 million or $1.41 per diluted share.

The table below details the regional breakdown of our first quarter 2010 production:

	Mid-Continent	ArkLaTex	South Texas & Gulf Coast	Permian	Rocky Mountain	Total (1)
First Quarter 2010 Production:						
Oil (MBbl)	61.3	19.4	136.8	445.8	862.2	1,525.5
Gas (MMcf)	8,352.8	3,104.7	2,648.0	949.3	1,511.9	16,566.6
Equivalent (MMCFE)	8,720.6	3,221.2	3,468.6	3,624.1	6,685.2	25,719.6
Avg. Daily Equivalents (MMCFE/d)	96.9	35.8	38.5	40.3	74.3	285.8
Relative percentage	34%	13%	13%	14%	26%	100%

(1) Totals may not add due to rounding

For the first quarter of 2010 our production and oil and gas production revenues have outperformed our initial budget for 2010 due to stronger than anticipated production results from our Mid-Continent and South Texas & Gulf Coast regions. Please refer to *Comparison of Financial Results and Trends between the three months ended March 31, 2010, and 2009,* below for additional discussion on production.

Net Profits Plan. For the three months ended March 31, 2010, the change in the value of this liability resulted in a non-cash benefit of $27.3 million compared with a $23.3 million benefit for the same period in 2009. Current year payments accrued as part of allocating the proceeds received from first quarter 2010 divestitures 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 from the Net Profits Plan have been expensed as compensation costs in the amounts of $7.5 million and $3.6 million for the three months ended March 31, 2010, and 2009, respectively. Additionally, the above described sales of oil and gas properties supporting a number of profit pools resulted in the accrual of payments under the Net Profits Plan of $18.2 million during the first quarter of 2010. These accrued cash payments are accounted for as a reduction of sale proceeds and impact the gain (loss) on divestiture activity in the accompanying consolidated statements of operations. There were no

Table of Contents

significant cash payments made or accrued under the Net Profits Plan as a result of divestitures during the first quarter of 2009.

The recurring Net Profits Plan 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 analysis 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 from the Net Profits Plan are now being categorized as general and administrative expense as compared to exploration expense. This is a function of the normal departure of employees who previously contributed to our exploration efforts.

The calculation of the estimated liability for the Net Profits Plan is highly sensitive to our price estimates and discount rate assumptions. For example, if we changed the commodity prices in our calculation by five percent, the liability recorded on the balance sheet at March 31, 2010, would differ by approximately $11 million. A one percentage point change in the discount rate would change the liability by approximately $7 million. We frequently re-evaluate the assumptions used in our calculations and consider the possible impacts stemming from the current market environment including current and future oil and gas prices, discount rates, and overall market conditions.

Outlook for the Remainder of 2010

Our development program entering 2010 was focused on the drilling of oil and rich gas projects. This decision has been reinforced as a result of a declining natural gas price outlook. We continue to evaluate ways to shift capital away from natural gas drilling wherever possible, except for activities necessary to satisfy leasehold commitments or key test wells in emerging resource plays. The most significant change from the plan we announced earlier this year is an increase in activity in the non-operated portion of our Eagle Ford shale program. We plan to continue operating two drilling rigs in the Eagle Ford shale program this year, although we now expect our partner to operate between four and six rigs on our joint venture acreage for the remainder of the year. This compares to two rigs that were assumed in our initial plan. As a result, we are increasing our Eagle Ford shale budget by roughly $68 million, most of which will be spent in the non-operated joint venture program in the Eagle Ford shale. We also anticipate that we will be making volume commitments for a portion of our Eagle Ford acreage later this year so midstream partners can begin building infrastructure to serve this play. Infrastructure investment is becoming larger and occurring at a faster pace than we previously anticipated. We have increased our facilities budget by $22 million to reflect increased levels of investment that are planned for Eagle Ford and Marcellus infrastructure. Offsetting these increases to our capital budget is a reduction of capital investment in the Haynesville shale program resulting from our recent sharing arrangement involving our East Texas acreage position as discussed in Note 13 Subsequent Event under Part I, Item 1 of this report. Under that arrangement, we will receive approximately $87 million dollars in carried drilling and completion costs. We will continue to operate a large portion of our East Texas Haynesville position. In exchange, our partner will be able to earn roughly 9,100 net acres in East Texas in two blocks located in Shelby and San Augustine Counties, Texas. The arrangement allows us to de-risk our Haynesville shale acreage in East Texas with considerably reduced capital investment on our part. Accordingly, we are reducing the Haynesville shale budget by $82 million to reflect the effect of this agreement. Given the decline in the outlook for natural gas prices, we are also reducing our capital program by approximately $8 million since we plan on deferring several wells in the Woodford and Marcellus shale programs. In total, our capital program remains unchanged at $725 million although it does reflect additional activity as a result of the Haynesville transaction.

Table of Contents

Financial Results of Operations and Additional Comparative Data

The table below provides information regarding selected production and financial information for the quarter ended March 31, 2010, and the immediately preceding three quarters. Additional details of per MCFE costs are contained later in this section.

	For the Three Months Ended			
	March 31, 2010	December 31, 2009	September 30, 2009	June 30, 2009
	(In millions, except production sales data)			
Production (BCFE)	25.7	26.1	26.4	28.2
Oil and gas production revenue, excluding the effects of hedging	$ 212.9	$ 187.6	$ 152.7	$ 145.3
Realized oil and gas hedge gain	$ 2.6	$ 13.4	$ 28.3	$ 43.3
Gain (loss) on divestiture activity	$ 121.0	$ 22.1	$ (11.3)	$ 1.3
Lease operating expense	$ 30.0	$ 34.3	$ 34.3	$ 35.6
Transportation costs	$ 4.1	$ 5.2	$ 5.3	$ 4.6
Production taxes	$ 14.2	$ 13.3	$ 9.0	$ 9.3
DD&A	$ 77.8	$ 75.1	$ 67.0	$ 70.4
Exploration	$ 13.9	$ 13.4	$ 15.7	$ 19.5
Impairment of proved properties	$	$ 21.6	$ 0.1	$ 6.0
Abandonment and impairment of unproved properties	$ 0.9	$ 25.2	$ 4.8	$ 11.6
General and administrative	$ 23.5	$ 20.7	$ 20.8	$ 18.2
Change in Net Profits Plan liability	$ (27.3)	$ 7.0	$ 6.8	$ 2.4
Unrealized derivative (gain) loss	$ (7.7)	$ 3.2	$ 4.1	$ 11.3
Net income (loss)	$ 126.2	$ 1.0	$ (4.4)	$ (8.3)
Percentage change from previous quarter:				
Production (BCFE)	(2)%	(1)%	(6)%	(1)%
Oil and gas production revenue, excluding the effects of hedging	13%	23%	5%	11%
Realized oil and gas hedge gain	(81)%	(53)%	(35)%	(22)%
Gain (loss) on divestiture activity	448%	(296)%	(969)%	(317)%
Lease operating expense	(13)%	%	(4)%	(14)%
Transportation costs	(21)%	(2)%	15%	(16)%
Production taxes	7%	48%	(3)%	2%
DD&A	4%	12%	(5)%	(23)%
Exploration	4%	(15)%	(19)%	43%
Impairment of proved properties	(100)%	21,500%	(98)%	(96)%
Abandonment and impairment of unproved properties	(96)%	425%	(59)%	197%
General and administrative	14%	%	14%	11%
Change in Net Profits Plan liability	(490)%	3%	183%	(110)%
Unrealized derivative (gain) loss	(341)%	(22)%	(64)%	528%
Net income (loss)	12,520%	(123)%	(47)%	(91)%

Changes in production volumes, oil and gas production revenues, and costs reflect the cyclical and highly volatile nature of our industry. We believe that the steady increase in industry activity is at a point where we will no longer continue to see the declines in lease operating costs that we experienced the last few quarters. Production taxes are largely dependent on the prices we receive for oil and natural gas. Depreciation, depletion, and amortization generally had been pressured upward in recent years as production related to properties acquired or developed in a higher cost environment became a larger percentage of our production mix. In the fourth quarter of 2009, a decrease in our underlying proved

Table of Contents

reserve volumes at year end 2009 resulting from price and performance revisions caused an increase in our DD&A rate. Our DD&A rate can fluctuate as a result of impairments and changes to our underlying proved reserve volumes. Additionally, the accounting treatment for assets that are classified as assets held for sale can also impact our DD&A rate since properties held for sale are no longer depreciated. A portion of our general and administrative expense is tied to the net revenues we generate, which are driven in large part by the realized commodity prices we receive for our production. The Net Profits Plan and a portion of our current short-term incentive compensation are tied to net revenues and therefore are subject to variability.

Table of Contents

A three-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 March 31, 2010		For the Three Months Ended March 31, 2009		Percent Change Between Periods
Net production volumes					
Oil (MBbl)		1,526		1,640	(7)%
Natural gas (MMcf)		16,567		18,515	(11)%
MMCFE (6:1)		25,720		28,354	(9)%
Average daily production					
Oil (Bbl per day)		16,950		18,220	(7)%
Natural gas (Mcf per day)		184,073		205,724	(11)%
MCFE per day (6:1)		285,773		315,041	(9)%
Oil & gas production revenues (1)					
Oil production revenue	$	102,148	$	72,412	41%
Gas production revenue		113,334		113,625	%
Total	$	215,482	$	186,037	16%
Oil & gas production expense					
Lease operating expense	$	30,030	$	41,248	(27)%
Transportation costs		4,094		5,459	(25)%
Production taxes		14,216		9,122	56%
Total	$	48,340	$	55,829	(13)%
Average realized sales price (1)					
Oil (per Bbl)	$	66.96	$	44.16	52%
Natural gas (per Mcf)	$	6.84	$	6.14	11%
Per MCFE Data:					
Average net realized price (1)	$	8.38	$	6.56	28%
Lease operating expenses		(1.17)		(1.45)	(19)%
Transportation costs		(0.16)		(0.19)	(16)%
Production taxes		(0.55)		(0.32)	72%
General and administrative		(0.91)		(0.57)	60%
Operating profit	$	5.59	$	4.03	39%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$	3.02	$	3.23	(7)%

(1) Includes the effects of hedging activities

We present per MCFE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe require analysis. Volatility in commodity prices has impacted our operating margins. The increase in our equivalent realized price for production corresponds with the upward move in commodity prices we have seen over the last few months. Our cost structure has improved on a quarter to quarter comparison due to the effects that lower commodity prices throughout 2009 had on industry activity. Our operating profit of $5.59 per MCFE for the first quarter of 2010 increased 39 percent from the $4.03 per MCFE we realized in the first quarter of 2009.

Average daily production for the first quarter of 2010 decreased nine percent to 285.8 MMCFE compared with 315.0 MMCFE for the same period in 2009, primarily driven by reduced capital spending in

Table of Contents

2009 and recent divestitures. Adjusting for divestitures our average daily production from retained properties for the first quarter of 2010 decreased two percent to 274.2 MMCFE compared with 278.5 MMCFE for the same period in 2009. For the three months ended March 31, 2010, our average net realized price increased $1.82 per MCFE to $8.38 per MCFE compared with the same period in 2009. Higher commodity prices, particularly for oil, were the principal driver of the increase. Unit cost decreased for the period as lease operating costs decreased $0.28 per MCFE to $1.17 per MCFE. This decrease was partially offset by a $0.23 per MCFE increase in production taxes, which increased to $0.55 per MCFE. LOE in the first quarter of 2009 reflected the cost structure of the more active industry environment that existed at that time. Pricing concessions over time by service providers as well as the divestiture of higher per unit cost assets have resulted in lower per unit LOE costs. Production taxes are highly correlated to commodity prices, and a portion of our general and administrative expense is linked to our profitability and cash flow. Transportation costs decreased $0.03 per MCFE to $0.16 per MCFE compared to the same period in 2009. Please refer to *Comparison of Financial Results and Trends between the three months ended March 31, 2010, and 2009,* below for additional discussion on oil and gas production expense.

For the three months ended March 31, 2010, depletion, depreciation, and amortization, including asset retirement obligation accretion expense, decreased $0.21 per MCFE to $3.02 per MCFE compared with the same period in 2009. Please refer to *Comparison of Financial Results and Trends between the three months ended March 31, 2010, and 2009,* below for additional discussion on DD&A. Exploration expense for the first quarter of 2010 was essentially flat at $13.9 million.

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):

		March 31, 2010		**December 31, 2009**	**Percent Change Between Periods**
Working capital deficit	$	74,667	$	87,625	(15)%
Long-term debt	$	269,020	$	454,902	(41)%
Stockholders equity	$	1,133,591	$	973,570	16%

	For the Three Months Ended March 31,				Percent Change Between Periods
		2010		**2009**	
Basic net income (loss) per common share	$	2.01	$	(1.41)	(243)%
Diluted net income (loss) per common share	$	1.96	$	(1.41)	(239)%
Basic weighted-average shares outstanding		62,792		62,335	1%
Diluted weighted-average shares outstanding		64,377		62,335	3%

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 any 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. A detailed explanation is presented in Note 5   Earnings per Share, in Part I, Item 1 of this report.

Table of Contents

Basic and diluted weighted-average common shares outstanding used in our March 31, 2010, and 2009, 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 18,214 and 15,502 shares of common stock during the three-month periods ended March 31, 2010, and 2009, respectively, as a result of stock option exercises. The number of RSUs that vested and settled during the first quarter of 2010 and 2009 were 48,725 and 118,018, respectively.

Additional Comparative Data in Tabular Form:

	Change Between the Three Months Ended March 31, 2010, and 2009
Increase in oil and gas production revenues, net of hedging (In thousands)	$ 29,445

Components of Revenue Increase:

Oil	
Realized price change per Bbl, net of hedging	$ 22.80
Realized price percentage change	52%
Production change (MBbl)	(114)
Production percentage change	(7)%
Natural Gas	
Realized price change per Mcf, net of hedging	$ 0.70
Realized price percentage change	11%
Production change (MMcf)	(1,948)
Production percentage change	(11)%

Production mix as a percentage of total oil and gas revenue and production:

	For the Three Months Ended March 31, 2010	2009
Revenue		
Oil	47%	39%
Natural gas	53%	61%
Production		
Oil	36%	35%
Natural gas	64%	65%

Table of Contents

Information regarding the effects of oil and gas hedging activity:

	For the Three Months Ended March 31, 2010	2009
Oil Hedging		
Percentage of oil production hedged	53%	48%
Oil volumes hedged (MBbl)	806	788
Increase (decrease) in oil revenue	$ (8.8) million	$ 16.0 million
Average realized oil price per Bbl before hedging	$ 72.73	$ 34.40
Average realized oil price per Bbl after hedging	$ 66.96	$ 44.16
Natural Gas Hedging		
Percentage of gas production hedged	51%	48%
Natural gas volumes hedged (MMBtu)	9.4 million	9.4 million
Increase in gas revenue	$ 11.4 million	$ 39.6 million
Average realized gas price per Mcf before hedging	$ 6.15	$ 4.00
Average realized gas price per Mcf after hedging	$ 6.84	$ 6.14

Information regarding the components of exploration expense:

Summary of Exploration Expense (In millions)	**For the Three Months Ended March 31, 2010**	**2009**
Geological and geophysical expenses	$ 3.6	$ 4.4
Exploratory dry hole expense	0.2	0.1
Overhead and other expenses	10.1	9.1
Total	$ 13.9	$ 13.6

Table of Contents

Comparison of Financial Results and Trends between the three months ended March 31, 2010, and 2009

Oil and gas production revenue. Average daily production decreased nine percent to 285.8 MMCFE for the quarter ended March 31, 2010, compared with 315.0 MMCFE for the quarter ended March 31, 2009. 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/(Decreased) (MMCFE/d)	Pre-Hedge Oil and Gas Revenue Added (In millions)	Production Costs Increase (Decrease) (In millions)
Mid-Continent	(4.6)	$ 17.8	$ 0.3
ArkLaTex	(11.9)	0.9	(3.1)
South Texas & Gulf Coast	10.9	17.5	2.3
Permian	(4.6)	19.3	0.5
Rocky Mountain	(19.0)	27.0	(7.5)
Total	(29.2)	$ 82.5	$ (7.5)

The largest regional decrease occurred in the Rocky Mountain region as a result of the loss of production related to the divestiture of non-strategic oil and gas assets that occurred in the fourth quarter of 2009 and first quarter of 2010. Production in the ArkLaTex decreased as a result of natural production decline and decreased capital investment in 2009 and 2010. The only production growth occurred in the South Texas & Gulf Coast region as a result of production from drilling activity in our Eagle Ford shale program by ourselves and our partner.

The following table summarizes the average realized prices we received in the first quarter of 2010 and 2009, before the effects of hedging. Prices for oil and gas increased between the two periods.

	For the Three Months Ended March 31,	
	2010	2009
Realized oil price ($/Bbl)	$ 72.73	$ 34.40
Realized gas price ($/Mcf)	$ 6.15	$ 4.00
Realized equivalent price ($/MCFE)	$ 8.28	$ 4.60

The combination of an 80 percent increase in commodity prices and nine percent decrease in production volumes between periods resulted in higher oil and gas revenue. We expect our realized price to trend with commodity prices. Excluding the properties that were divested of in the first quarter of 2010, we anticipate our production volumes in the second quarter of 2010 to remain flat with a sequential increase in production during the third and fourth quarters of 2010.

Realized oil and gas hedge gain. We recorded a net realized hedge gain of $2.6 million for the three-month period ended March 31, 2010, related to settlements on oil and gas hedges, compared with $55.6 million for the same period in 2009, as a result of an increase in commodity prices on a quarter-to- quarter comparison.

Gain (loss) on divestiture activity. We had a $121.0 million net gain on divestiture activity for the quarter ended March 31, 2010, compared with a $599,000 net loss on sale for the comparable period of 2009, due primarily to the divestiture of non-core oil and gas properties located in our Rocky Mountain region that occurred in the first quarter of 2010. The final gain on sale of proved properties will be adjusted for normal post-closing adjustments and is expected to be finalized during the second half of 2010. We expect to continue to evaluate potential divestitures of non-strategic properties in future periods.

Table of Contents

Marketed gas system revenue and expense. Marketed gas system revenue increased $8.4 million to $21.8 million for the quarter ended March 31, 2010, compared with $13.4 million for the comparable period of 2009. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased $8.6 million to $22.0 million for the quarter ended March 31, 2010, compared with $13.4 million for the comparable period of 2009. The net margin has stayed relatively consistent with historical performance. We expect that marketed gas system revenue and expense will continue to coincide with increases and decreases in production and our net realized price.

Oil and gas production expense. Total production costs decreased $7.5 million, or 13 percent, to $48.3 million for the first quarter of 2010 from $55.8 million in the comparable period of 2009. Total oil and gas production costs per MCFE decreased $0.08 to $1.88 for the first quarter of 2010, compared with $1.96 for the same period in 2009. This decrease is comprised of the following:

- The $0.34 decrease in recurring LOE on a per MCFE basis reflects the reduction in pricing offered by service providers as a result of the decrease in activity across the exploration and production sector in 2009. Additionally, the sale of non-core properties with higher per unit LOE costs in the first quarter of 2010 resulted in lower LOE on a per unit basis year over year. Activity in the sector has increased in recent months, particularly in areas with oil projects. We expect the various resources needed to service our industry to become more sought after and harder to secure as a result of this increase in activity. As a result we expect to see upward pressure on LOE throughout the remainder of the year.

- A $0.03 decrease in overall transportation cost on a per MCFE basis was driven by a decrease in transportation costs incurred on our properties located in the Rocky Mountain region as a result of the Hanging Woman Basin divestiture that occurred in the fourth quarter of 2009

- A $0.23 per MCFE increase in production taxes is due to the increase in pre-hedge oil and gas revenues between periods, particularly in the oil-weighted Rocky Mountain and Permian Basin regions

- A $0.06 overall increase in workover LOE on a per MCFE basis relating to an increase in workover activity in the Permian and Rocky Mountain regions due to our shift toward oil-weighted projects.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A decreased $13.9 million or 15 percent to $77.8 million for the three-month period ended March 31, 2010, compared with $91.7 million for the same period in 2009. DD&A expense per MCFE decreased seven percent to $3.02 for the three-month period ended March 31, 2010, compared to $3.23 for the same period in 2009. The current quarter s DD&A per MCFE was slightly lower when compared with the same period in 2009 due to the impact that the significantly lower commodity prices had on our internal estimate of proved reserves in the first quarter of 2009. The decrease in proved reserves in the first quarter of 2009 was a result of lower realized natural gas prices made worse by wider than normal price differentials, primarily in the Mid-Continent region, and the reduction of proved reserves in our Hanging Woman Basin coalbed methane project. Any future proved property impairments and changes in underlying proved reserve volumes will continue to impact our DD&A expense.

Exploration. Exploration expense remained relatively flat at $13.9 million for the three-month period ended March 31, 2010, compared with $13.6 million for the same period in 2009.

Impairment of proved properties. There were no proved property impairments recorded for the three-month period ended March 31, 2010. We recorded a $147.0 million impairment of proved oil and gas properties for the three-month period ended March 31, 2009. This 2009 impairment was driven by a significant decrease in realized gas prices, particularly in the Mid-Continent region, as well as a reserve

Table of Contents

write-down for our coalbed methane project at Hanging Woman Basin. We generally expect proved property impairments will be more likely to occur in periods of low commodity prices.

Impairment of materials inventory. There were no materials inventory impairments recorded for the three-month period ended March 31, 2010. We recorded an $8.6 million impairment of materials inventory for the three-month period ended March 31, 2009. The inventory write-downs were due to a decrease in the value of tubular goods and other raw materials. Impairments of materials inventory are driven by fluctuations in the cost of materials, which are in turn impacted by the level of activity in the oil and gas industry, which generally trends with commodity prices.

General and administrative. General and administrative expense increased $7.1 million or 43 percent to $23.5 million for the quarter ended March 31, 2010, compared with $16.4 million for the comparable period of 2009. On a per unit basis, G&A expense increased $0.34 to $0.91 per MCFE for the first quarter of 2010 compared to $0.57 per MCFE for the same three-month period in 2009.

General and administrative expense increased due to a $3.7 million increase in cash payments accrued under the Net Profits Plan and a $2.5 million increase in cash bonus and long-term incentive compensation expense for the quarter ended March 31, 2010, compared with the same period in 2009.

The increase in Net Profits Plan payments to plan participants was the result of higher commodity prices, pools entering the higher 20 percent payout level as described further in Note 7 of Part 1, Item 1of this report, and the 2005 pool entering payout for the first time. As of the end of the first quarter of 2010, 18 of our 21 pools are in payout status. No additional pools are expected to reach payout in 2010. We expect payments made under the Net Profits Plan to continue to trend with commodity prices. The increase in cash bonus and long-term incentive compensation expense reflects the improvement in our performance and the anticipated achievement of various performance criteria set by our Compensation Committee, as well as compensation expense associated with PSAs granted in the third quarter in 2009.

Change in Net Profits Plan liability. For the quarter ended March 31, 2010, this non-cash item was a benefit of $27.3 million compared to $23.3 million for the same period in 2009. We saw a reduction in the Net Profits Plan liability as a result of the impact our first quarter 2010 divestitures had on the amount and timing of future payments. The application of these proceeds accelerated the timing of the payments to plan participants from future years into the current period thereby reducing the future liability for 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. We generally expect the change in this liability to trend with commodity prices.

Additionally, the Company made or accrued cash payments under the Net Profits Plan of $18.2 million for the three-month period ended March 31, 2010, as a result of the Legacy and Sequel divestitures. The cash proceeds for those transactions are accounted for as a reduction of sale proceeds which in turn impacts the gain (loss) on divestiture activity in the accompanying consolidated statements of operations. There were no cash payments accrued under the Net Profits Plan during the first quarter of 2009 as a result of divestitures.

Unrealized derivative (gain) loss. We recognized a gain of $7.7 million for the three months ended March 31, 2010, compared to a loss of $1.8 million for the same period in 2009. This non-cash item is driven by the change in the value of our hedge position, as well as the portion of that position that is considered ineffective for accounting purposes. Please refer to our discussion under the heading *Hedging Activities.*

Other expense. Other expense decreased $4.7 million to $952,000 for the quarter ended March 31, 2010, compared with $5.6 million for the same period in 2009. In the first quarter of 2009, we incurred $2.3 million of expense related to the assignment of a drilling rig contract in our Rocky Mountain

Table of Contents

region. We also incurred an additional loss related to hurricanes of $2.1 million for the three months ended March 31, 2009, which related to an increase in our estimate of the remediation cost for the Vermilion 281 platform that was lost in Hurricane Ike.

Income tax expense. We recorded income tax expense of $74.9 million for the first quarter of 2010 compared to income tax benefit of $53.9 million for the first quarter of 2009 resulting in effective tax rates of 37.3 percent and 38.1 percent, respectively. The change in income tax expense is primarily the result of the differences in components of net income discussed above. The decrease in the effective tax rate from 2009 reflects divestiture activity in 2010 affecting 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 drilling activity throughout 2009 and 2010. Our cash tax benefit decreased for the first quarter of 2010 compared to the same period of 2009 due to the impact on estimated taxable income from reduced revenue resulting from decreased commodity prices. However, the current portion of our tax expense is greater in the first quarter of 2010 compared to the first quarter of 2009 due to the impact of our non-core asset divestitures in 2010. These trends are expected to continue throughout the remainder of 2010 based upon our current projected capital expenditures program and commodity price outlook.

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 expect our generated cash flow from operations in 2010, including the net cash proceeds of $239.2 million from the Rocky Mountain oil and other non-core asset divestiture packages, to fund our exploration and development budget for 2010. Accordingly, we do not expect to access the capital markets in 2010. We anticipate we will continue to periodically evaluate our property base to identify and divest of properties we consider non-core to our strategic goals.

Our primary sources of liquidity are the cash flows provided by our operating activities, use of our credit facility, sales of non-core properties, carrying cost funding and sharing arrangements with third parties for particular exploration and development programs, 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, all of 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 our oil and gas sales through the use of derivative contracts. The borrowing base on our credit facility could be reduced as a result of lower commodity prices or sales of non-core producing properties. Historically, decreases in commodity prices have limited our industry s access to the capital markets. We believe the public debt markets are currently accessible. Equity and convertible debt issuances are also available to us as alternative financing sources. We do not anticipate the need to raise public debt or equity financing in the near term, however these are options we would consider under the appropriate circumstances. We intend to rely on our credit facility for borrowings.

Current Credit Facility

On April 14, 2009, we entered into an amended $1.0 billion senior secured revolving credit facility with twelve participating banks. The initial borrowing base was set at $900 million. On March 17, 2010, the lending group redetermined our reserve-backed borrowing base under the credit facility at $900 million. We have been provided a $678 million commitment amount by the bank group. The new amended credit facility agreement has a maturity date of July 31, 2012. Management believes that the current commitment is sufficient for our liquidity needs. To date, we have experienced no issues drawing upon our credit facility. No individual bank participating in the credit facility represents more than 16 percent of the lending commitments under the credit facility. We monitor the credit environment closely and have frequent discussions with the lending group.

As of April 27, 2010, we had $677.5 million of available borrowing capacity under this facility. We have a single letter of credit outstanding under our credit facility, in the amount of $483,000 as of April 27, 2010, which reduces the amount available under the commitment amount on a dollar-for-dollar basis. Borrowings under the facility are secured by mortgages on the majority of our oil and gas properties. Please refer to Note 5 Long-term Debt in Part IV, Item 15 of our Annual Report on Form 10-K for the year ended December 31, 2009, for our borrowing base utilization grid.

Our weighted-average interest rate for the three-month periods ended March 31, 2010, and 2009, was 7.2 percent and 4.3 percent, respectively. Our weighted-average interest rates in the current and prior year include cash interest payments, fees paid on the unused portion of the credit facility s aggregate commitment amount, letter of credit fees, amortization of the convertible notes debt discount, and amortization of deferred financing costs. The increase in our weighted-average interest rate from the comparative quarter in 2009 is the result of the new pricing grid and increase in the amortization of deferred financing costs related to our amended credit facility that we entered into in April 2009, an increase in our commitment fees due to an increase in the commitment amount, an increase in the amount of the unused portion of the commitment and an increase in the fee paid on the unused portion of the commitment, and a lower average credit facility balance.

We are subject to customary financial and non-financial covenants under our credit facility, including limitations on dividend payments and requirements to maintain certain financial ratios, which include debt to earnings before interest, taxes, depreciation, and amortization (EBITDA) of not more than 3.5 to 1.0 and also include a current ratio as defined by our credit agreement of not less than 1.0 to 1.0. As of March 31, 2010, our debt to EBITDA ratio and current ratio as defined by our credit agreement were 0.64 and 3.19, 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 three months of 2010 we spent $132.4 million for exploration and development capital expenditures. These amounts differ from our costs 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 outflows were funded using cash inflows from operations, proceeds from the sale of assets, 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 2010 will exceed our operating cash flow, and we plan to fund this shortfall with the proceeds received from our non-core asset divestitures that closed during the first quarter of 2010. 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, investing 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 capital expenditure budget to assess changes in current and projected cash flows, acquisition and divestiture 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

Table of Contents

factors including certain provisions of our existing bank credit facility agreement, compliance with securities laws, and the terms and provisions of our stock repurchase program. There have been no share repurchases to date in 2010, and we do not plan to repurchase shares in the remainder of 2010.

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

The following table presents amount and percentage changes in cash flows between the three-month periods ended March 31, 2010, and 2009. The analysis following the table should be read in conjunction with our consolidated statements of cash flows in Part I, Item 1 of this report.

	For the Three Months Ended March 31, 2010	2009	Change	Percent Change
	(In thousands)			
Net cash provided by operating activities	$ 153,892	$ 125,175	$ 28,717	23%
Net cash provided by (used in) investing activities	$ 64,142	$ (128,267)	$ 192,409	(150)%
Net cash used in financing activities	$ (188,259)	$ (828)	$ (187,431)	22637%

Analysis of Cash Flow Changes Between the Three Months Ended March 31, 2010, and March 31, 2009

Operating activities. Cash received from oil and gas production revenue increased $48.0 million to $200.3 million for the first quarter of 2010, compared with $152.3 million for the first quarter of 2009. Additionally, cash paid for LOE decreased $7.5 million to $33.2 million for the first quarter of 2010, compared with $40.7 million for the first quarter of 2009.

Investing activities. We had cash provided by investing activities of $64.1 million for the three months ended March 31, 2010, compared with expending $128.3 million of cash for investing activities in the comparable period of 2009. We received $239.2 million from the sale of non-core properties primarily in the Rocky Mountain region for the three months ended March 31, 2010. In conjunction with the sale of non-core properties we had a $36.2 million deposit to restricted cash. There were no major divestitures for the same period in 2009. Cash outflows for capital expenditures remained relatively flat for the three months ended March 31, 2010, compared with the same period in 2009.

Financing activities. Net repayments on our credit facility increased by $187.0 million for the three-month period ended March 31, 2010, compared with the same period in 2009. We reduced our credit facility balance to zero in the first quarter of 2010, but expect it to gradually increase during the rest of 2010.

Table of Contents

Capital Expenditures

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

	For the Three Months Ended March 31, 2010	2009
	(In thousands)	
Development costs (1)	$ 40,437	$ 73,763
Exploration costs	91,326	21,630
Acquisitions		
Proved properties		53
Unproved properties - other	14,973	9,369
Total, including asset retirement obligations (2)	$ 146,736	$ 104,815

(1) Includes capitalized interest of $624,000 in 2010 and $470,000 in 2009.

(2) Includes amounts relating to estimated asset retirement obligations of $625,000 in 2010 and $356,000 in 2009.

Costs incurred for capital and exploration activities during the first three months of 2010 increased $36.4 million or 38 percent compared to the same period in 2009. This increase in capital and exploration activities during the first three months of 2010 compared with the same period in 2009 reflects a stable and improving economic environment and an expectation of higher cash flows provided by operating activities and divestiture proceeds.

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

Commodity Price Risk and Interest Rate Risk

We are exposed to market risk, including the effects of changes in oil and gas commodity prices and changes in interest rates as discussed below under the caption *Summary of Interest Rate Risk.* Changes in interest rates can affect the amount of interest we earn on our cash, cash equivalents, and the amount of interest we pay on borrowings under our revolving credit facility. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate 3.50% Senior Convertible Notes, but do affect their fair market value.

There has been no material change to the natural gas and crude oil price sensitivity analysis previously disclosed. Refer to the corresponding section under Part II, Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2009.

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 10 Derivative Financial Instruments in Part I, Item 1 of this report for additional information regarding accounting for our derivative transactions.

Table of Contents

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 March 31, 2010, our hedged positions of anticipated production through the fourth quarter of 2012 totaled approximately 6 million Bbls of oil, 54 million MMBtu of natural gas, and 1 million Bbls of natural gas liquids. As of April 27, 2010, we have hedge contracts in place through the first quarter 2013 for a total of approximately 6 million Bbls of anticipated crude oil production, 54 million MMBtu of anticipated natural gas production, and 2 million Bbls of anticipated natural gas liquids production.

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

The following tables describe the volumes, average contract prices, and fair values of contracts we have in place as of March 31, 2010, and April 27, 2010. The Company seeks to minimize ineffectiveness by entering into oil derivative contracts indexed to NYMEX WTI, natural gas derivative contracts indexed to regional index prices associated with pipelines in proximity to the Company s areas of production, and NGL derivative contracts indexed to Oil Price Information Service Mont Belvieu. 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.

Table of Contents

Oil Contracts

Oil Swaps

Contract Period	Volumes (Bbls)	Weighted-Average Contract Price (per Bbl)	Fair Value at March 31, 2010 Liability (in thousands)
Second quarter 2010	426,000	$ 69.46	$ 6,291
Third quarter 2010	393,000	$ 68.77	6,345
Fourth quarter 2010	309,000	$ 66.06	5,915
2011	1,164,000	$ 67.06	21,425
2012	1,051,400	$ 82.19	4,528
All oil swap contracts	3,343,400		$ 44,504

Oil Collars

Contract Period	NYMEX WTI Volumes (Bbls)	Weighted-Average Floor Price (per Bbl)	Weighted-Average Ceiling Price (per Bbl)	Fair Value at March 31, 2010 Liability (in thousands)
Second quarter 2010	341,000	$ 50.00	$ 64.91	$ 6,614
Third quarter 2010	344,500	$ 50.00	$ 64.91	7,136
Fourth quarter 2010	344,500	$ 50.00	$ 64.91	7,469
2011	1,236,000	$ 50.00	$ 63.70	29,264
All oil collars	2,266,000			$ 50,483

Table of Contents

Gas Contracts

Gas Swaps

Contract Period	Volumes (MMBtu)	Weighted-Average Contract Price (per MMBtu)	Fair Value at March 31, 2010 Asset (in thousands)
Second quarter 2010			
IF ANR OK	150,000	$ 5.31	$ 235
IF CIG	200,000	$ 5.16	314
IF EL PASO	390,000	$ 6.00	854
IF HSC	1,870,000	$ 7.80	7,290
IF NGPL	430,000	$ 5.23	644
IF NNG VENTURA	360,000	$ 5.71	649
IF PEPL	170,000	$ 5.23	258
IF RELIANT	1,250,000	$ 5.10	1,749
IF TETCO STX	250,000	$ 5.64	463
NYMEX Henry Hub	960,000	$ 6.75	2,740
Third quarter 2010			
IF ANR OK	70,000	$ 5.64	114
IF CIG	240,000	$ 5.38	373
IF EL PASO	370,000	$ 6.33	830
IF HSC	1,350,000	$ 8.03	5,236
IF NGPL	500,000	$ 5.43	716
IF NNG VENTURA	360,000	$ 5.89	620
IF PEPL	230,000	$ 5.56	360
IF RELIANT	1,190,000	$ 5.37	1,682
IF TETCO STX	230,000	$ 5.81	412
NYMEX Henry Hub	960,000	$ 6.94	2,662
Fourth quarter 2010			
IF ANR OK	140,000	$ 5.97	204
IF CIG	270,000	$ 5.87	388
IF EL PASO	370,000	$ 6.43	698
IF HSC	590,000	$ 8.61	2,320
IF NGPL	430,000	$ 5.61	461
IF NNG VENTURA	360,000	$ 6.34	572
IF PEPL	520,000	$ 5.92	744
IF RELIANT	1,350,000	$ 5.71	1,679
IF TETCO STX	180,000	$ 6.23	298
NYMEX Henry Hub	840,000	$ 7.52	2,308

Table of Contents

Gas Swaps (continued)

Contract Period	Volumes (MMBtu)		Weighted-Average Contract Price (per MMBtu)		Fair Value at March 31, 2010 Asset (in thousands)
2011					
IF ANR OK	500,000	$	6.10		470
IF CIG	1,030,000	$	5.96		966
IF EL PASO	1,780,000	$	6.35		2,164
IF HSC	360,000	$	9.01		1,331
IF NGPL	1,040,000	$	6.09		979
IF NNG VENTURA	1,200,000	$	6.36		1,224
IF PEPL	1,830,000	$	6.04		1,742
IF RELIANT	4,510,000	$	6.13		4,587
IF TETCO STX	1,420,000	$	6.51		1,874
NYMEX Henry Hub	2,130,000	$	6.72		2,992
2012					
IF ANR OK	360,000	$	6.18		232
IF CIG	1,020,000	$	5.77		286
IF EL PASO	850,000	$	6.04		367
IF NGPL	660,000	$	6.34		537
IF NNG VENTURA	620,000	$	6.51		412
IF PEPL	2,730,000	$	6.25		2,142
IF RELIANT	2,440,000	$	6.22		1,592
IF TETCO STX	660,000	$	6.30		396
All gas swap contracts	41,720,000			$	62,166

Table of Contents

Gas Collars

Contract Period	Volumes (MMBtu)	Weighted-Average Floor Price (per MMBtu)	Weighted-Average Ceiling Price (per MMBtu)	Fair Value at March 31, 2010 Asset (in thousands)
Second quarter 2010				
IF CIG	510,000	$ 4.85	$ 7.08	$ 647
IF HSC	150,000	$ 5.57	$ 7.88	250
IF PEPL	1,235,000	$ 5.31	$ 7.61	1,946
NYMEX Henry Hub	60,000	$ 6.00	$ 8.38	126
Third quarter 2010				
IF CIG	510,000	$ 4.85	$ 7.08	577
IF HSC	150,000	$ 5.57	$ 7.88	224
IF PEPL	1,240,000	$ 5.31	$ 7.61	1,735
NYMEX Henry Hub	60,000	$ 6.00	$ 8.38	113
Fourth quarter 2010				
IF CIG	510,000	$ 4.85	$ 7.08	411
IF HSC	150,000	$ 5.57	$ 7.88	175
IF PEPL	1,240,000	$ 5.31	$ 7.61	1,331
NYMEX Henry Hub	60,000	$ 6.00	$ 8.38	87
2011				
IF CIG	1,800,000	$ 5.00	$ 6.32	693
IF HSC	480,000	$ 5.57	$ 6.77	293
IF PEPL	4,225,000	$ 5.31	$ 6.51	2,238
NYMEX Henry Hub	120,000	$ 6.00	$ 7.25	109
All gas collars	12,500,000			$ 10,955

Natural Gas Liquid Contracts

Natural Gas Liquid Swaps

	Volumes (approx. Bbls)	Weighted-Average Contract Price (per Bbl)	Fair Value at March 31, 2010 Asset/(Liability) (in thousands)
Second quarter 2010	191,000	$ 46.28	$ 119
Third quarter 2010	179,000	$ 46.20	83
Fourth quarter 2010	169,000	$ 46.16	(27)
2011	480,000	$ 43.20	(560)
2012	214,000	$ 43.70	(195)

All natural gas liquid swaps	1,233,000	$	(580)

46

Table of Contents

Hedge Contracts Entered into After March 31, 2010

The following table includes all hedges entered into subsequent to March 31, 2010, through April 27, 2010.

Oil Contracts

Oil Collars

Contract Period	NYMEX WTI Volumes (Bbls)	Weighted-Average Floor Price (per Bbl)	Weighted-Average Ceiling Price (per Bbl)
2012	163,700	$ 80.00	$ 100.85
2013	282,600	$ 80.00	$ 100.85
All oil collars	446,300		

Natural Gas Liquid Contracts

Natural Gas Liquid Swaps

Contract Period	Volumes (Bbls)	Weighted-Average Contract Price (per Bbl)
2010	110,700	$ 41.69
2011	233,900	$ 45.86
2012	277,700	$ 44.69
2013	84,100	$ 44.94
All natural gas liquid swaps	706,400	

Refer to Note 10 Derivative Financial Instruments in Part I, Item 1 of this report for additional information regarding our oil and gas hedges.

Table of Contents

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 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 no floating-rate debt outstanding as of March 31, 2010. Our fixed-rate debt outstanding, net of debt discount, at this same date was $269.0 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 entities 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 March 31, 2010, 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, 2009, and to the footnote disclosures included in Part I, Item 1 of this report.

New Accounting Pronouncements

Please see Note 12 Recent Accounting Pronouncements 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 and reliable process in our industry of creating artificial cracks, or fractures, in deep underground rock formations through the pressurized injection of water, sand and other additives to enable oil or natural gas to move more easily through the rock pores to a production well. This process is often necessary to produce commercial quantities of oil and natural gas from many reservoirs, especially shale rock formations. We routinely utilize hydraulic fracturing in many of our reservoirs, and our Eagle Ford, Haynesville, Marcellus, Woodford, and other 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. On March 18, 2010, the Environmental Protection Agency (EPA) announced that it has allocated $1.9

million in 2010 and has requested funding in fiscal year 2011 for conducting a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health. In addition, various state and local governments are considering increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas, such as watersheds. Additional regulations and permitting requirements could lead to significant operational delays and increased operating costs, could make it more difficult to perform hydraulic fracturing, and could impair our ability to produce commercial quantities of oil and natural gas from certain reservoirs.

In December 2009, the EPA published its findings that emissions of carbon dioxide, which is a byproduct of the burning of refined oil products and natural gas, methane, which is a primary component of natural gas, and other greenhouse gases present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth s atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Accordingly, the EPA had proposed regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and that could also lead to the imposition of greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources. In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. On March 23, 2010, the EPA announced a proposed rulemaking that would expand its final rule on reporting of greenhouse gas emissions to include owners and operators of onshore oil and natural gas production. If the proposed rule is finalized in its current form, monitoring of those newly covered sources would commence on January 1, 2011. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur increased costs to reduce emissions of greenhouse gases associated with our operations and could adversely affect demand for the oil and natural gas that we produce.

In addition, in June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009 (ACESA), which would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. ACESA would require a 17% reduction in greenhouse gas emissions from 2005 levels by 2020, and just over an 80% reduction of such emissions by 2050. Under this legislation, the EPA would issue a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. The cost of these allowances would be expected to escalate significantly over time. The net effect of ACESA would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. The U.S. Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions, and the Obama administration has indicated its support of legislation to reduce greenhouse gas emissions through an emission allowance system. In addition, several states have considered initiatives to regulate emissions of greenhouse gases, primarily through the planned development of greenhouse gas emissions inventories and/or regional greenhouse gas cap and trade programs. Although it is not possible at this time to predict when the U.S. Senate may act on climate change legislation or how any bill passed by the Senate would be reconciled with ACESA, any future federal or state laws or regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could adversely affect the demand for the oil and natural gas that we produce. Additional information about the potential effect of climate change issues on our business is presented under the Climate Change caption in the Management s Discussion and Analysis of Financial Condition and Results of Operations section of our Annual Report on Form 10-K for the year ended December 31, 2009.

Table of Contents

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, will, and similar expressions are intended to identify forward-looking statements. Forward-looking statements appear in a number of places in this Form 10-Q, and include statements about such matters as:

- *The amount and nature of future capital expenditures and the availability of liquidity and capital resources to fund capital expenditures*
- *The drilling of wells and other exploration and development activities and plans, as well as possible future acquisitions*
- *Proved 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 2009 Annual Report on Form 10-K 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 or climate change initiatives*
- *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 distressed capital and credit market conditions*
- *Our ability to replace reserves and sustain production*
- *Unexpected drilling conditions and results*

Table of Contents

- *Unsuccessful exploration and development drilling*

- *The risks of hedging strategies, including the possibility of realizing lower prices on oil and natural gas sales as a result of commodity price risk management activities*

- *The pending nature of reported divestiture plans for certain non-core oil and gas properties as well as the ability to complete divestiture transactions*

- *The uncertain nature of the expected benefits from acquisitions and divestitures of oil and natural gas properties, including uncertainties in evaluating oil and natural gas reserves of acquired properties and associated potential liabilities, and uncertainties with respect to the amount of proceeds that may be received from divestitures*

- *The imprecise nature of oil and natural gas reserve estimates*

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

- *Declines in the values of our oil and natural gas properties resulting in impairment charges and write-downs*

- *The ability of purchasers of production to pay for amounts purchased*

- *Drilling and operating service availability*

- *Uncertainties in cash flow*

- *The financial strength of hedge contract counterparties and credit facility participants, and the risk that one or more of these parties may not satisfy their contractual commitments*

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

- *The potential effects of increased levels of debt financing*

- *Our ability to compete effectively against other independent and major oil and natural gas companies and*

- *Litigation, environmental matters, the potential impact of government regulations, and the use of management estimates.*

We caution you that forward-looking statements are not guarantees of future performance and that actual results or performance may be materially different from those expressed or implied in the forward-looking statements. Although we may from time to time voluntarily update our prior forward-looking statements, we disclaim any commitment to do so except as required by securities laws.

Table of Contents

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, 2009, in response to Item 1A of Part I of such Form 10-K.

Table of Contents

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

(c) The following table provides information about purchases by the Company or any affiliated purchaser (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the fiscal quarter ended March 31, 2010, 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)
01/01/10 01/31/10	985	$	34.75		3,072,184
02/01/10 02/28/10	14,735	$	32.58		3,072,184
03/01/10 03/31/10	380	$	34.08		3,072,184
Total:	16,100	$	32.75		3,072,184

(1) Includes 16,100 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.

Table of Contents

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 1.01 Entry into a Material Definitive Agreement.

On April 29, 2010, the Company entered into a Carry and Earning Agreement (the CEA) with EnCana Oil & Gas (USA) Inc., (EnCana) which effectively provides for EnCana to earn 95 percent of St. Mary s interest in approximately 8,400 net acres in a portion of the Company s East Texas Haynesville shale acreage, as well as an interest in several wells currently drilling, and five percent of St. Mary s interest in approximately 23,400 net acres in a separate portion of the Company s Haynesville acreage in East Texas. In exchange for these interests, EnCana has agreed to invest $91.3 million to fund the drilling and completion costs of horizontal wells in the portion of the lands where the Company is retaining 95 percent. Of this, $86.7 million represents St. Mary s carried drilling and completion costs. The Company received an initial payment of $45.6 million on April 29, 2010, and the CEA provides that the Company will receive the balance of the committed funds less any adjustments allowed under the CEA for title defects within 30 days of the completion of the fourth commitment well.

ITEM 6. EXHIBITS

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

Exhibit	**Description**
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002
32.1**	Certification pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002

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* Filed with this report.

** Furnished with this report.

Table of Contents

SIGNATURES

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

	ST. MARY LAND & EXPLORATION COMPANY	
May 4, 2010	By:	/s/ ANTHONY J. BEST Anthony J. Best President and Chief Executive Officer
May 4, 2010	By:	/s/ A. WADE PURSELL A. Wade Pursell Executive Vice President and Chief Financial Officer
May 4, 2010	By:	/s/ MARK T. SOLOMON Mark T. Solomon Controller