SM Energy Co
Form 10-Q
November 03, 2010

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2010

Commission File Number 001-31539

SM ENERGY COMPANY

(Exact name of registrant as specified in its charter)

Delaware	**41-0518430**
(State or other jurisdiction	(I.R.S. Employer

of incorporation or organization)	Identification No.)
1775 Sherman Street, Suite 1200, Denver, Colorado	**80203**
(Address of principal executive offices)	(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 x 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.

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 October 27, 2010 the registrant had 63,055,280 shares of common stock, $0.01 par value, outstanding.

Table of Contents

SM ENERGY COMPANY

INDEX

Table of Contents

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

SM ENERGY COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(In thousands, except share amounts)

	September 30, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 7,089	$ 10,649
Accounts receivable	121,010	116,136
Refundable income taxes	1,371	32,773
Prepaid expenses and other	12,847	14,259
Derivative asset	56,199	30,295
Deferred income taxes		4,934
Total current assets	198,516	209,046
Property and equipment (successful efforts method), at cost:		
Land	1,483	1,371
Proved oil and gas properties	3,137,262	2,797,341
Less - accumulated depletion, depreciation, and amortization	(1,234,802)	(1,053,518)
Unproved oil and gas properties, net of impairment allowance of $62,395 in 2010 and $66,570 in 2009	79,466	132,370
Wells in progress	129,102	65,771
Materials inventory, at lower of cost or market	27,810	24,467
Oil and gas properties held for sale less accumulated depletion, depreciation, and amortization	114,863	145,392
Other property and equipment, net of accumulated depreciation of $17,301 in 2010 and $14,550 in 2009	19,048	14,404
	2,274,232	2,127,598
Other noncurrent assets:		
Derivative asset	29,444	8,251
Other noncurrent assets	16,805	16,041
Total other noncurrent assets	46,249	24,292
Total Assets	**$ 2,518,997**	**$ 2,360,936**
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 316,179	$ 236,242
Derivative liability	53,732	53,929
Deposit associated with oil and gas properties held for sale		6,500
Deferred income taxes	1,143	
Total current liabilities	371,054	296,671
Noncurrent liabilities:		
Long-term credit facility	2,000	188,000
Senior convertible notes, net of unamortized discount of $14,096 in 2010, and $20,598 in 2009	273,404	266,902
Asset retirement obligation	64,286	60,289
Asset retirement obligation associated with oil and gas properties held for sale	3,076	18,126
Net Profits Plan liability	140,506	170,291

Deferred income taxes	422,021	308,189
Derivative liability	25,450	65,499
Other noncurrent liabilities	14,749	13,399
Total noncurrent liabilities	945,492	1,090,695
Commitments and contingencies (note 6)		
Stockholders equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued: 63,147,613 shares in 2010 and 62,899,122 shares in 2009; outstanding, net of treasury shares: 63,044,978 shares in 2010 and 62,772,229 shares in 2009	631	629
Additional paid-in capital	183,203	160,516
Treasury stock, at cost: 102,635 shares in 2010 and 126,893 shares in 2009	(456)	(1,204)
Retained earnings	1,004,984	851,583
Accumulated other comprehensive income (loss)	14,089	(37,954)
Total stockholders equity	1,202,451	973,570
Total Liabilities and Stockholders Equity	**$ 2,518,997**	**$ 2,360,936**

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

Table of Contents

SM ENERGY COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

(In thousands, except per share amounts)

	For the Three Months Ended September 30, 2010	For the Three Months Ended September 30, 2009	For the Nine Months Ended September 30, 2010	For the Nine Months Ended September 30, 2009
Operating revenues and other income:				
Oil and gas production revenue	$ 197,354	$ 152,651	$ 586,128	$ 428,347
Realized oil and gas hedge gain	8,847	28,331	20,771	127,230
Gain (loss) on divestiture activity	4,184	(11,277)	132,183	(10,632)
Marketed gas system and other operating revenue	16,499	16,082	59,634	45,260
Total operating revenues and other income	226,884	185,787	798,716	590,205
Operating expenses:				
Oil and gas production expense	44,606	48,634	138,114	153,928
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	83,800	66,958	241,335	229,061
Exploration	14,437	15,733	42,833	48,821
Impairment of proved properties		91		153,183
Abandonment and impairment of unproved properties	1,719	4,761	4,998	20,294
Impairment of materials inventory		2,114		13,449
General and administrative	26,219	20,790	75,103	55,349
Change in Net Profits Plan liability	4,086	6,804	(29,785)	(14,038)
Marketed gas system expense	14,697	14,360	52,550	41,352
Unrealized derivative (gain) loss	5,727	4,117	(4,095)	17,251
Other expense	541	968	2,071	12,424
Total operating expenses	195,832	185,330	523,124	731,074
Income (loss) from operations	31,052	457	275,592	(140,869)
Nonoperating income (expense):				
Interest income	85	90	268	217
Interest expense	(6,339)	(7,565)	(19,469)	(21,324)
Income (loss) before income taxes	24,798	(7,018)	256,391	(161,976)
Income tax benefit (expense)	(9,346)	2,603	(96,693)	61,616
Net income (loss)	**$ 15,452**	**$ (4,415)**	**$ 159,698**	**$ (100,360)**
Basic weighted-average common shares outstanding	63,031	62,505	62,914	62,420
Diluted weighted-average common shares outstanding	64,794	62,505	64,599	62,420
Basic net income (loss) per common share	**$ 0.25**	**$ (0.07)**	**$ 2.54**	**$ (1.61)**
	$ 0.24	**$ (0.07)**	**$ 2.47**	**$ (1.61)**

Diluted net income (loss) per common share	

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

Table of Contents

SM ENERGY COMPANY AND SUBSIDIARIES

CONDENSED 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, 2009	**62,899,122**	**$ 629**	**$ 160,516**	**(126,893)**	**$ (1,204)**	**$ 851,583**	**$ (37,954)**	**$ 973,570**
Comprehensive income, net of tax:								
Net income						159,698		159,698
Change in derivative instrument fair value							50,136	50,136
Reclassification to earnings							1,903	1,903
Minimum pension liability adjustment							4	4
Total comprehensive income								211,741
Cash dividends, $ 0.10 per share						(6,297)		(6,297)
Issuance of common stock under Employee Stock Purchase Plan	27,456		799					799
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	57,687	1	(909)					(908)
Sale of common stock, including income tax benefit of stock option exercises	163,348	1	3,692					3,693
Stock-based compensation expense			19,105	24,258	748			19,853

Balances, September 30, 2010	**63,147,613**	**$ 631**	**$ 183,203**	**(102,635)**	**$ (456)**	**$ 1,004,984**	**$ 14,089**	**$ 1,202,451**
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						(100,360)		(100,360)
Change in derivative instrument fair value							(12,810)	(12,810)
Reclassification to earnings							(57,979)	(57,979)
Minimum pension liability adjustment							4	4
Total comprehensive loss								(171,145)
Cash dividends, $ 0.10 per share						(6,247)		(6,247)
Issuance of common stock under Employee Stock Purchase Plan	49,767		858					858
Issuance of common stock upon settlement of RSUs following expiration of restriction period, net of shares used for tax withholdings, including income tax cost of RSUs	89,236	1	(3,157)					(3,156)
Sale of common stock, including income tax benefit of stock option exercises	33,014		320					320
Stock-based compensation expense	1,250		12,316	50,094	662			12,978
Balances, September 30, 2009	**62,638,839**	**$ 626**	**$ 151,620**	**(126,893)**	**$ (1,230)**	**$ 850,593**	**$ (5,492)**	**$ 996,117**

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

Table of Contents

SM ENERGY COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(In thousands)

	For the Nine Months Ended September 30, 2010	2009
Cash flows from operating activities:		
Net income (loss)	$ 159,698	$ (100,360)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
(Gain) loss on divestiture activity	(132,183)	10,632
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	241,335	229,061
Exploratory dry hole expense	289	4,849
Impairment of proved properties		153,183
Abandonment and impairment of unproved properties	4,998	20,294
Impairment of materials inventory		13,449
Stock-based compensation expense	19,853	12,978
Change in Net Profits Plan liability	(29,785)	(14,038)
Unrealized derivative (gain) loss	(4,095)	17,251
Loss related to hurricanes		8,273
Amortization of debt discount and deferred financing costs	10,022	8,922
Deferred income taxes	85,695	(69,082)
Plugging and abandonment	(7,106)	(12,110)
Other	(3,085)	1,432
Changes in current assets and liabilities:		
Accounts receivable	(4,937)	58,844
Refundable income taxes	31,402	10,340
Prepaid expenses and other	512	(8,660)
Accounts payable and accrued expenses	47,123	7,794
Excess income tax benefit from the exercise of stock options	(1,376)	
Net cash provided by operating activities	**418,360**	**353,052**
Cash flows from investing activities:		
Net proceeds from sale of oil and gas properties	259,501	1,137
Proceeds from insurance settlement		15,336
Capital expenditures	(488,684)	(292,466)
Acquisition of oil and gas properties	(685)	(58)
Receipts from restricted cash		14,398
Receipts from short-term investments		1,002
Other	(6,492)	
Net cash used in investing activities	**(236,360)**	**(260,651)**
Cash flows from financing activities:		
Proceeds from credit facility	315,059	1,898,500
Repayment of credit facility	(501,059)	(1,963,500)
Debt issuance costs related to credit facility		(11,074)
Proceeds from sale of common stock	3,116	1,179
Dividends paid	(3,144)	(3,120)
Excess income tax benefit from the exercise of stock options	1,376	

Other		(908)		
Net cash used in financing activities		**(185,560)**		**(78,015)**
Net change in cash and cash equivalents		(3,560)		14,386
Cash and cash equivalents at beginning of period		10,649		6,131
Cash and cash equivalents at end of period	**$**	**7,089**	**$**	**20,517**

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

Table of Contents

SM ENERGY COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED) (Continued)

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

	For the Nine Months Ended September 30, 2010	2009
	(In thousands)	
Cash paid for interest	$ 9,091	$ 11,150
Cash refunded for income taxes	$ (24,949)	$ (10,119)

As of September 30, 2010, and 2009, $133.3 million, and $59.8 million, respectively, are included as additions to oil and gas properties and accounts payable and accrued expenses in the accompanying condensed consolidated balance sheets. These oil and gas additions are reflected as cash used in investing activities in the periods that the payables are settled.

Dividends of approximately $3.2 million have been declared by the Company s Board of Directors, but not paid, as of September 30, 2010.

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

Table of Contents

SM ENERGY COMPANY AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

September 30, 2010

Note 1 The Company and Business

SM Energy Company (SM Energy or the Company), formerly named St. Mary Land & Exploration Company or referred to as St. Mary, is an independent energy company engaged in the exploration, exploitation, development, acquisition, and production of natural gas, natural gas liquids (NGLs), 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 SM Energy have been prepared in accordance with accounting principles generally accepted in the United States for interim financial information and the instructions to Form 10-Q and Regulation S-X. They do not include all information and notes required by generally accepted accounting principles (GAAP) for complete financial statements. However, except as disclosed herein, there has been no material change in the information disclosed in the notes to consolidated financial statements included in SM Energy 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 SM Energy, the Company evaluated subsequent events after the balance sheet date of September 30, 2010, through the filing date 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 condensed 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

Southern Rockies Divestiture

In July 2010 the Company completed the divestiture related to the non-strategic assets that were classified as held for sale at June 30, 2010. The gain on sale related to the divestiture is approximately $2.6 million. The final sale price is subject to normal post-closing adjustments and is expected to be finalized in the fourth quarter of 2010. The estimated gain on sale related to the divestiture may be impacted by the forthcoming post-closing adjustments mentioned above. The Company determined that the sale did not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

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

Table of Contents

(Legacy). The transaction had an effective date of November 1, 2009. Total cash received, before commission costs and Net Profits Interest Bonus Plan (Net Profits Plan) payments, was $125.3 million, of which $6.5 million was received as a deposit in December 2009. The final gain on sale related to the divestiture is approximately $65.0 million. The Company determined that the sale did not qualify for discontinued operations accounting under financial statement presentation authoritative guidance. 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 (the Internal Revenue Code).

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, LLC (collectively referred to as Sequel). The transaction had an effective date of November 1, 2009. Total cash received, before commission costs and Net Profits Plan payments, was $129.1 million. The final sale price is subject to normal post-closing adjustments and is expected to be finalized during the fourth quarter of 2010. The estimated gain on sale related to the divestiture is approximately $52.9 million and may be impacted by the forthcoming post-closing adjustments mentioned above. The Company determined that the sale did not qualify for discontinued operations accounting under financial statement presentation authoritative guidance. A portion of the transaction was structured to qualify as a like-kind exchange under Section 1031 of the Internal Revenue Code.

Assets Held for Sale

In accordance with property, plant, and equipment authoritative guidance, 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.

In August 2010 the Company engaged two outside firms to market for sale certain non-core oil and gas properties located in the Rocky Mountain, Mid-Continent, and Permian regions. The Mid-Continent properties being marketed include all of our Marcellus shale assets in North Central Pennsylvania. As of September 30, 2010, the accompanying condensed consolidated balance sheets (accompanying balance sheets) present $114.9 million in book value of assets held for sale, net of accumulated depletion, depreciation, and amortization. Additionally, the corresponding asset retirement obligation liability of $3.1 million is separately presented. The Company determined that these planned asset sales do not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

Note 4 Income Taxes

Income tax (expense) benefit for the nine-month periods ended September 30, 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.

Table of Contents

The provision for income taxes consists of the following:

	For the Three Months Ended September 30, 2010	2009	For the Nine Months Ended September 30, 2010	2009
	(In thousands)			
Current portion of income tax (expense):				
Federal	$ (2,194)	$ (2,881)	$ (10,410)	$ (6,129)
State	(277)	(451)	(588)	(1,337)
Deferred portion of income tax (expense) benefit	(6,875)	5,935	(85,695)	69,082
Total income tax (expense) benefit	$ (9,346)	$ 2,603	$ (96,693)	$ 61,616
Effective tax rate	37.7%	37.1%	37.7%	38.0%

A change in the Company s effective tax rate 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 September 30, 2010, and the Company s anticipated drilling budget for the rest of 2010 applied against the Company s cumulative temporary timing differences caused an increase in tax rate for the third quarter of 2010 when compared to the same period of 2009. The rate is also impacted period to period by estimates for the domestic production activities deduction, percentage depletion, and for potential permanent state tax items which affect the presented periods differently due to oil and gas price variability and the impact of non-core asset sales.

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 2007. During the first quarter of 2010, the Internal Revenue Service initiated an audit of SM Energy for the 2006 tax year as a result of a net operating loss carryback from the Company s 2008 tax year. The audit was focused primarily on compensation related issues. The audit was successfully concluded in the second quarter of 2010 with no changes to Company reported amounts. As of September 30, 2010, the Company is awaiting approval from the Joint Committee on Taxation to receive a $5.5 million refund from its 2006 tax year net operating loss carryback claim, which is included in refundable income taxes on the accompanying balance sheets. On July 20, 2010, the Company received $22.9 million related to an initial claim for net operating loss carry back from its 2009 tax year to its 2005 tax year. The Company s remaining refundable income tax balance at September 30, 2010, reflects additional net operating loss carry back from filing a revised income tax return for the 2009 tax year prior to the extended return due date. At the end of the third quarter of 2010, the Company was advised that the Internal Revenue Service will begin a full audit of the Company s 2009 tax year in the fourth quarter of 2010.

The Company s 2005 federal 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.

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 this calculation consist of unvested RSUs, in-the-money outstanding options to purchase the Company s common stock, contingent Performance Share

Table of Contents

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 this conversion feature. The 3.50% Senior Convertible Notes have not been dilutive for any reporting period that they have been outstanding and therefore do not impact the diluted earnings per share calculation for the three-month or nine-month periods ended September 30, 2010, and 2009.

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. The number of potentially dilutive shares related to PSAs is based on the number of 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 refer to Note 7 Compensation Plans under the heading *Performance Share Awards Under the Equity Incentive Compensation Plan*.

The treasury stock method is used to measure the dilutive impact of stock options, RSUs, 3.50% Senior Convertible Notes, and PSAs. 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 or nine-month periods ended September 30, 2009, because the Company recorded a loss for each of those periods. Unvested RSUs, contingent PSAs, and in-the-money options had a dilutive impact for the three-month and nine-month periods ended September 30, 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 September 30,		For the Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
	(In thousands, except per share amounts)			
Net income (loss)	$ 15,452	$ (4,415)	$ 159,698	$ (100,360)
Basic weighted-average common stock outstanding	63,031	62,505	62,914	62,420
Add: dilutive effect of stock options, unvested RSUs, and contingent PSAs	1,763		1,685	
Add: dilutive effect of 3.50% senior convertible notes				
Diluted weighted-average common shares outstanding	64,794	62,505	64,599	62,420
Basic net income (loss) per common share	$ 0.25	$ (0.07)	$ 2.54	$ (1.61)
Diluted net income (loss) per common share	$ 0.24	$ (0.07)	$ 2.47	$ (1.61)

Table of Contents

Note 6 Commitments and Contingencies

During the first nine months of 2010, the Company entered into two natural gas gathering through-put commitments that as of September 30, 2010, require a minimum volume delivery of 574 Bcf by the end of 2021. The Company will be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments. If a shortfall in the minimum volume commitment is projected, the Company has certain rights to arrange for 3rd party gas to deliver into the gathering lines and such volume will be counted towards the minimum commitment. In the third quarter of 2010 the Company entered into several new long-term drilling rig contracts that extend through 2014. The table below shows the undiscounted cash flows associated with the deficiency payments related to the Company s through-put commitments, as well as commitments associated with the Company s new drilling rig contracts as of September 30, 2010.

Years Ending December 31,	**Undiscounted Cash Outflows (In thousands)**
2010	$ 7,775
2011	28,300
2012	36,068
2013	46,988
2014	33,147
Thereafter	119,873
Total	$ 272,151

The above amounts include commitments under a gas services agreement entered into by the Company effective as of July 1, 2010, for natural gas production from the Company s Eagle Ford shale assets. Under that agreement, the Company has committed Eagle Ford production up to a maximum level of 200,000 MMBTU per day over a ten-year term beginning in 2011, and in the event that no gas is delivered the aggregate deficiency payments will total $154.7 million.

Subsequent to September 30, 2010, the Company entered into a fracturing service agreement and an additional long-term drilling rig contract, which extends through 2013. The total commitment for both agreements is $79.8 million.

Note 7 Compensation Plans

Cash Bonus Plan

During the first quarters 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 condensed consolidated statements of operations (accompanying statements of operations) was $3.1 million and $3.2 million of cash bonus expense related to the specific performance year for the three-month periods ended September 30, 2010, and 2009, and $9.2 million and $8.5 million for the nine-month periods ended September 30, 2010, and 2009, respectively.

Performance Share Awards Under the Equity Incentive Compensation Plan

PSAs represent the right to receive, upon the completion of a 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 to an index of certain peer companies TSR for the performance period.

Total stock-based compensation expense related to PSAs for the three-month periods ended September 30, 2010, and 2009, was $5.6 million and $3.2 million, respectively, and $13.0 million and $5.7

Table of Contents

million for the nine-month periods ended September 30, 2010, and 2009, respectively. As of September 30, 2010, there was $29.0 million of total unrecognized compensation expense related to unvested PSAs that is being amortized through 2013.

A summary of the status and activity of PSAs for the nine-month period ended September 30, 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	387,651	$ 52.35
Vested (1)	(210,801)	$ 31.17
Forfeited	(102,149)	$ 32.48
Non-vested and outstanding, at September 30, 2010	1,143,791	$ 39.49

(1) The numbers of shares vested assume a one multiplier. The final number of shares vested may vary depending on the ending three-year multiplier, which ranges from zero to two.

On July 1, 2010, the Company granted 387,651 PSAs with a performance period ending June 30, 2013, and a fair value of $20.3 million. This grant was part of the Company s regular annual compensation process. These PSAs will vest 1/7th on July 1, 2011, 2/7ths on July 1, 2012, and 4/7ths on July 1, 2013.

Restricted Stock Unit Incentive Program Under the Equity Incentive Compensation Plan

Total RSU compensation expense for both the three-month periods ended September 30, 2010, and 2009, was $2.1 million, and $5.7 million and $5.9 million for the nine-month periods ended September 30, 2010, and 2009, respectively. As of September 30, 2010, there was $8.2 million of total unrecognized compensation expense related to unvested RSU awards that is being amortized through 2013.

During the first nine months of 2010, the Company settled 83,008 RSUs that relate to awards granted in 2009, 2008 and 2007 through the issuance of shares of the Company s common stock in accordance with the terms of the RSU awards. As a result, the Company issued 57,687 shares of common stock associated with these grants. The remaining 25,321 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 nine-month period ended September 30, 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	126,821	$	40.17
Vested	(81,775)	$	31.45
Forfeited	(31,358)	$	36.46
Non-vested and outstanding, at September 30, 2010	420,811	$	36.82

Table of Contents

During the third quarter of 2010 the Company granted 126,821 RSUs with a fair value of $5.1 million, as part of its regular annual compensation process. Each RSU represents a right to receive one share of the Company s common stock to be delivered upon settlement of the vested RSU. These RSUs will vest 1/7th on July 1, 2011, 2/7ths on July 1, 2012, and 4/7ths on July 1, 2013.

Stock Option Grants Under Prior Stock Option Plans

The following table summarizes stock option activity for the nine months ended September 30, 2010:

	Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (In years)	Aggregate Intrinsic Value (In thousands)
Outstanding, beginning of period	1,274,920	$ 13.31		
Exercised	(163,348)	$ 14.19		
Forfeited		$		
Outstanding, end of period	1,111,572	$ 13.18	2.4	$ 26,988
Vested at end of period	1,111,572	$ 13.18	2.4	$ 26,988
Exercisable, end of period	1,111,572	$ 13.18	2.4	$ 26,988

As of September 30, 2010, there was no unrecognized compensation expense related to stock option awards.

Director Shares

In May 2010 and 2009 the Company issued 24,258 and 50,094 shares, respectively, of the Company s common stock from treasury to the Company s non-employee directors. The shares were issued pursuant to the Company s Equity Incentive Compensation Plan. The Company recorded $33,000 and $26,000 of compensation expense for the three-month periods ended September 30, 2010, and 2009, respectively, and $748,000 and $662,000 for the nine-month periods ended September 30, 2010, and 2009, respectively.

Employee Stock Purchase Plan

Under the Company s Employee Stock Purchase Plan (the ESPP), eligible employees may purchase shares of the Company s common stock through payroll deductions of up to 15 percent of eligible compensation. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on the first or last day of the purchase period, and shares issued under the ESPP are restricted for a period of six months from the date issued. The ESPP is intended to qualify under Section 423 of the Internal Revenue Code. The Company has set aside 2,000,000 shares of its common stock to be available for issuance under the ESPP, of which 1,440,819 shares are available for issuance as of

September 30, 2010. The fair value of ESPP grants is measured at the date of grant using the Black-Scholes option-pricing model. There were 27,456 and 49,767 shares issued under the ESPP during the first nine months of 2010 and 2009, respectively. The Company expensed $162,000 and $153,000 for the three-month periods ended September 30, 2010, and 2009, respectively, and $425,000 and $694,000 for the nine-month periods ended September 30, 2010, and 2009, respectively, based on the estimated fair values on the respective grant dates.

Table of Contents

Net Profits Plan

Prior to 2008, all oil and gas wells that were completed or acquired during each year were assigned to a specific pool for that respective year under the Company s legacy Net Profits Plan. 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 a 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 100 percent of pool 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 September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In thousands)			
General and administrative expense	$ 3,918	$ 5,168	$ 16,233	$ 12,942
Exploration expense	638	239	1,896	1,116
Total	$ 4,556	$ 5,407	$ 18,129	$ 14,058

Additionally, the Company made cash payments under the Net Profits Plan of $686,000 and $20.8 million for the three-month and nine-month periods ended September 30, 2010, respectively, as a result of sales proceeds mainly 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 statements of operations. There were no cash payments made under the Net Profits Plan as a result of divestitures that occurred during the first nine months 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 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 September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In thousands)			
General and administrative expense (benefit)	$ 4,062	$ 5,807	$ (26,670)	$ (12,923)

Exploration expense (benefit)	24	997	(3,115)	(1,115)
Total	$ 4,086	$ 6,804	$ (29,785)	$ (14,038)

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 September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In thousands)			
Service cost	$ 848	$ 625	$ 2,544	$ 1,875
Interest cost	280	234	840	701
Expected return on plan assets	(159)	(108)	(477)	(323)
Amortization of net actuarial loss	91	93	273	279
Net periodic benefit cost	$ 1,060	$ 844	$ 3,180	$ 2,532

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, SM Energy is not required to make a minimum contribution to the pension plans in 2010. However, the Company contributed $1.7 million in September 2010 based upon the preliminary funding results analysis completed in April 2010 in order to maintain an adequate funding level to provide retirement benefits to current and future plan participants and to maintain an adequate funding level to provide lump sum payments if elected by participants.

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 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 condensed 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

Table of Contents

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 commerciality, or if 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 Nine Months Ended September 30, (In thousands)
Beginning asset retirement obligation	$ 102,080
Liabilities incurred	3,501
Liabilities settled	(26,962)
Accretion expense	4,237
Revision to estimated cash flow	(10)
Ending asset retirement obligation	$ 82,846

As of September 30, 2010, the Company had $3.1 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 balance sheets. Additionally, as of September 30, 2010, accounts payable and accrued expenses contained $15.5 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 exposure to potentially adverse market changes in oil, gas, and NGL 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 NGLs. As of September 30, 2010, the Company has hedge contracts in place through the second quarter of 2013 for a total of approximately 5 million Bbls of anticipated crude oil production, 42 million MMBtu of anticipated natural gas production, and 2 million Bbls of anticipated NGL production. As of October 27, 2010, the Company has hedge contracts in place through the third quarter of 2013 for a total of approximately 7 million Bbls of anticipated crude oil production, 42 million MMBtu of anticipated natural gas production, and 2 million Bbls of anticipated NGL production.

The Company attempts to qualify its oil, natural gas, and NGL derivative instruments as cash flow hedges for accounting purposes under derivative and hedging authoritative guidance. 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 September 30, 2010, all oil, natural gas, and NGL derivative instruments qualified as cash flow hedges for accounting purposes. The Company anticipates that all forecasted

Table of Contents

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 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 was a net asset of $6.5 million and a net liability of $80.9 million at September 30, 2010, and December 31, 2009, respectively.

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

	Location on Consolidated Balance Sheets	**Fair Value at September 30, 2010**	**Fair Value at December 31, 2009**
		(In thousands)	
Derivative assets designated as cash flow hedges:			
Commodity contracts	Current assets Derivative asset	$ 56,199	$ 30,295
Commodity contracts	Other noncurrent assets Derivative asset	29,444	8,251
Total derivative assets designated as cash flow hedges		$ 85,643	$ 38,546
Derivative liabilities designated as cash flow hedges:			
Commodity contracts	Current liabilities Derivative liability	$ (53,732)	$ (53,929)
Commodity contracts	Noncurrent liabilities Derivative liability	(25,450)	(65,499)
Total derivative liabilities designated as cash flow hedges		$ (79,182)	$ (119,428)

Realized gains or losses from the settlement of oil, natural gas, and NGL derivative contracts are reported in the total operating revenues and other income section of the accompanying statements of operations. The Company realized a net gain of $8.8 million and $28.3 million from its oil, natural gas, and NGL derivative contracts for the three months ended September 30, 2010, and 2009, respectively, and realized a net gain of $20.8 million and $127.2 million from its oil, natural gas, and NGL derivative contracts for the nine months ended September 30, 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 balance sheets until the hedged item is realized in earnings upon the sale of the associated hedged production. As of September 30, 2010, the amount of unrealized gain, net of deferred income taxes, to be reclassified from accumulated other comprehensive

Table of Contents

income to realized oil and gas hedge gain in the Company s accompanying statements of operations in the next twelve months is $10.2 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 Company s areas of production, and NGL derivative contracts indexed to Oil Price Information Service Mont Belvieu. The Company s derivative contracts utilize the same respective indices or pricing points as the Company s sales contracts. As a result, the derivative contracts used by the Company are highly correlated with prices received upon the sale of the underlying hedged production.

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

	Derivatives Qualifying as Cash Flow Hedges	Location on Consolidated Balance Sheets	Balance as of September 30, 2010	Balance as of December 31, 2009
			(In thousands)	
Amount of (gain) loss on derivatives recognized in OCI during the period (effective portion)	Commodity contracts	Accumulated other comprehensive income (loss)	$ (50,136)	$ 35,977

The following table details the effect of derivative instruments on other comprehensive income (loss) and the accompanying statements of operations (net of income tax):

	Derivatives Qualifying as Cash Flow Hedges	Location on Consolidated Statements of Operations	For the Three Months Ended September 30, 2010	2009	For the Nine Months Ended September 30, 2010	2009
			(In thousands)			
Amount of (gain) loss reclassified from AOCI to realized oil and gas hedge gain (loss) (effective portion)	Commodity Contracts	Realized oil and gas hedge gain	$ 2,685	$(12,485)	$ 1,903	$(57,979)

Table of Contents

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

Derivatives Qualifying as Cash Flow Hedges	Location on Consolidated Statements of Operations	(Gain) Loss Recognized in Earnings (Ineffective Portion) For the Three Months Ended September 30, 2010	2009	For the Nine Months Ended September 30, 2010	2009
		(In thousands)			
Commodity contracts	Unrealized derivative (gain) loss	$ 5,727	$ 4,117	$ (4,095)	$ 17,251

Credit Related Contingent Features

As of September 30, 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 instances where the Company is in a liability position. When the Company is in a liability position with the 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 September 30, 2010, or October 27, 2010.

Convertible Note Derivative Instruments

The contingent interest provision of the 3.50% Senior Convertible Notes is an embedded derivative instrument. As of September 30, 2010, and December 31, 2009, the value of this derivative was determined to be immaterial.

Note 11 Fair Value Measurements

The Company follows fair value measurement authoritative guidance for all assets and liabilities measured at fair value. That guidance 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. Market or observable inputs are the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The hierarchy for grouping these assets and liabilities is 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

Table of Contents

The following is a listing of the Company s financial assets and liabilities that are measured at fair value on a recurring basis and where they are classified within the hierarchy as of September 30, 2010:

	Level 1	Level 2 (In thousands)	Level 3
Assets:			
Derivatives	$	$ 85,643	$
Liabilities:			
Derivatives	$	$ 79,182	$
Net Profits Plan	$	$	$ 140,506

There were no nonfinancial assets or liabilities measured at fair value on a nonrecurring basis at September 30, 2010.

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, gas, and NGL hedges. Fair values are based upon interpolated data. The Company derives internal valuation estimates that take into account nonperformance risk by considering counterparties credit ratings, the Company s credit rating, and the time value of money. 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 and nonperformance risk of a specific counterparty to determine the fair value of the instrument. In order to mitigate the risk of nonperformance, 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 may attempt to novate trades with parties deemed to have more risk on a relative basis to a more stable and less risky 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

Table of Contents

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 SM Energy 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 GAAP and with other marketplace participants, the Company recognizes that third parties may use different methodologies or assumptions to determine the fair value of certain financial instruments that could result in a different estimate of fair value at the reporting date.

Net Profits Plan

The Net Profits Plan is a standalone liability for which there is no available market price, principal market, or market participants. The inputs available for this instrument are unobservable, and are 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 prices, 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 of five one-year strip prices with the fifth year s pricing then carried out indefinitely. The average price was adjusted to include the effects of hedging 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, natural gas, and NGL commodity markets.

If the commodity prices used in the calculation changed by five percent, the liability recorded at September 30, 2010, would differ by approximately $11 million. A one percentage point increase in the discount rate would decrease the liability by approximately $6 million whereas a one percentage point decrease in the discount rate would increase the liability by $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.

Table of Contents

The following table reflects the activity for the Net Profits Plan liability measured at fair value using Level 3 inputs:

	For the Three Months Ended September 30, 2010	2009	For the Nine Months Ended September 30, 2010	2009
	(In thousands)			
Beginning balance	$ 136,420	$ 156,524	$ 170,291	$ 177,366
Net increase (decrease) in liability (a)	9,328	12,211	9,110	20
Net settlements (a)(b)	(5,242)	(5,407)	(38,895)	(14,058)
Transfers in (out) of Level 3				
Ending balance	$ 140,506	$ 163,328	$ 140,506	$ 163,328

(a) Net changes in the Net Profits Plan liability are shown in the Change in Net Profits Plan liability line item of the accompanying statements of operations.

(b) Settlements represent cash payments made or accrued under the Net Profits Plan. Settlements for the three months and nine months ended September 30, 2010, include $686,000 and $20.8 million, respectively, of cash payments made related primarily to the Legacy and Sequel divestitures. There were no cash payments made under the Net Profits Plan as a result of divestitures for the three months or nine months ended September 30, 2009.

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 $301 million and $290 million as of September 30, 2010, and December 31, 2009, respectively.

Proved Oil and Gas Properties

Proved oil and gas property costs are evaluated for impairment against undiscounted future cash flows and reduced to fair value (discounted future cash flows) if the sum of the expected undiscounted future cash flows is less than net book value. 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.

Of the $2.1 billion 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 balance sheets at September 30, 2010.

Materials Inventory

Materials inventory is valued at the lower of cost or market. The Company uses Level 2 inputs to measure the fair value of materials inventory, which is primarily comprised of tubular goods. The Company uses third party market quotes and compares the quotes to the book value of the materials inventory. If the book value exceeds the quoted market price, the Company reduces the book value to the market price. The considered factors result in an estimated exit-price that management believes provides a reasonable and consistent methodology for valuing materials inventory.

Of the $24.5 million of materials inventory, $13.9 million was measured at fair value at December 31, 2009. There was no materials inventory measured at fair value within the accompanying balance sheets at September 30, 2010.

Asset Retirement Obligations

The Company estimates asset retirement obligations pursuant to asset retirement and environmental obligations authoritative guidance. The Company uses the income valuation technique to determine the fair value of the asset retirement obligation liability at the point of inception by applying a credit-adjusted risk-free rate, which takes into account the Company s credit risk, the time value of money, and the current economic state, to the undiscounted expected abandonment cash flows. Given the unobservable nature of the inputs, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. There were no asset retirement obligations measured at fair value within the accompanying consolidated balance sheets at September 30, 2010, or December 31, 2009.

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 new fair value measurement authoritative guidance 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 did not have a material impact on the Company s consolidated financial statements. Please refer to Note 11 Fair Value Measurements.

The Company will apply new fair value measurement authoritative guidance requiring that purchases, sales, issuances, and settlements for Level 3 measurements be disclosed. These disclosures are effective for interim and annual reporting periods beginning after December 15, 2010. The Company will apply this new guidance in the Company s Quarterly Report on Form 10-Q for the period ended March 31, 2011. The adoption of this guidance is not expected to have a material impact on the Company s financial statements.

The Company adopted new subsequent events authoritative guidance 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 Carry and Earning Agreement

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 SM Energy 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 and five percent of SM Energy 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 interest. Of this, $86.7 million represents SM Energy s carried drilling and completion costs, which is 95 percent of the total well costs to be 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 SM Energy 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, NGLs, 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. In the first nine months of 2010 we have generated significant gains and cash proceeds from the sale of non-strategic oil and gas properties. Our oil and gas reserves and operations are concentrated primarily in the Eagle Ford shale in South Texas; the Williston Basin in North Dakota and Montana; the Mid-Continent Anadarko and Arkoma basins; the Permian Basin; North Central Pennsylvania; and the productive formations of East Texas and North Louisiana. We have developed a balanced and diverse portfolio of proved reserves, development drilling opportunities, and unconventional resource prospects. Please refer to *Marketing of non-core properties* for additional discussion related to our Marcellus assets in North Central Pennsylvania.

Our mission is to deliver outstanding net asset value per share growth to our investors via attractive oil and gas investments. Our strategy is to focus on early entrance into existing and emerging resource plays in North America. By entering these plays earlier, we believe that we can capture larger resource potential at lower cost. We believe this organic-centered model allows for more stable and predictable production and proved reserves growth.

Financial Standing and Liquidity

In the third quarter of 2010, the borrowing base on our credit facility was redetermined and was increased from $900.0 million to $1.1 billion. The commitment amount of the bank group remained unchanged at $678.0 million. At the end of the third quarter 2010, we had $2.0 million outstanding under the revolving credit facility. As of October 27, 2010, the outstanding balance was $38.0 million. 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 and asset levels, credit standing, and relationships with the participants in our bank group, we believe we will be able to extend our existing facility or obtain a replacement 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 some combination of 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 cash flows from operations in 2010 plus proceeds from our divestitures of non-core assets to fund the majority of our capital budget for 2010. We plan to use our credit facility to fund the remaining portion of our capital program. Accordingly, we do not anticipate accessing the equity or public debt markets for the remainder of 2010. Given the size of our commitments associated with our existing inventory of potential drilling projects, our requirements for funding could increase significantly in 2011 and beyond. As a result, we may consider accessing the capital markets, and other alternatives, as we determine how to best fund our capital program. We continue to believe we have adequate liquidity available as discussed 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 the prices we receive for oil, natural gas, and NGLs, which can fluctuate dramatically. Please refer to *Comparison of Financial Results and Trends between the three months ended September 30, 2010, and 2009* and *Comparison of Financial Results and Trends between the nine months ended September 30, 2010, and 2009* for the realized price tables for the respective periods. 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 the majority of our natural gas sales as they occur at the wellhead and accordingly do not present a separate production stream for the NGLs processed from our natural gas 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. Sales of processed NGLs are immaterial and are included with our natural gas production and sales. Our crude oil is sold using contracts that pay us either the average of the NYMEX WTI daily settlement price or the average of alternative posted prices for the periods in which the crude oil is produced, adjusted for quality, transportation, and location differentials.

The following table is a summary of commodity price data for the third quarters of 2010 and 2009 and the second quarter of 2010:

	For the Three Months Ended		
	September 30, 2010	**June 30, 2010**	**September 30, 2009**
Crude Oil (per Bbl):			
Average NYMEX price	$ 76.09	$ 77.88	$ 68.30
Realized price, before the effects of hedging	$ 68.56	$ 70.92	$ 61.93
Net realized price, including the effects of hedging	$ 64.28	$ 65.17	$ 62.65
Natural Gas (per Mcf):			
Average NYMEX price	$ 4.28	$ 4.33	$ 3.41
Realized price, before the effects of hedging	$ 4.93	$ 4.54	$ 3.37
Net realized price, including the effects of hedging	$ 5.81	$ 5.59	$ 4.95

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 oil prices. Historically, NGL prices 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, which could increase supplies and negatively impact future pricing. Future natural gas prices are facing downward pressure as a result of a supply overhang resulting from high levels of drilling activity across the country, as well as tepid demand recovery due to the economic recession in the United States. The 12-month strip prices for NYMEX WTI crude oil and NYMEX Henry Hub natural gas as of September 30, 2010, were $83.42 per Bbl and $4.29 per MMBTU, respectively. Comparable prices as of October 27, 2010, were $84.52 per Bbl and $4.02 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 September 30, 2010, our net natural gas price realization was positively

Table of Contents

impacted by $15.6 million of realized hedge settlements and our net oil price realization was negatively impacted by $6.8 million of realized hedge settlements.

Hedging Activities

On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act was enacted into law. This financial reform legislation includes provisions that require over-the-counter derivative transactions to be executed through an exchange or centrally cleared. The Dodd-Frank Act requires the Commodities Futures Trading Commission (the CFTC) and the Securities and Exchange Commission (the SEC) to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. On October 1, 2010, the CFTC introduced its first series of proposed rules coming out of the Dodd-Frank Act. The effect of the proposed rules and any additional regulations on our business is currently uncertain. Of particular concern, the Dodd-Frank Act does not explicitly exempt end users (such as us) from the requirements to post margin in connection with hedging activities. While several senators have indicated that it was not the intent of the Dodd-Frank Act to require margin from end users, the exemption is not explicit in the Dodd-Frank Act. Final rules on major provisions in the legislation, such as new margin requirements, will be established through rulemakings and will not take effect until 12 months after the date of enactment. Although we cannot predict the ultimate outcome of these rulemakings, new regulations in this area may result in increased costs and cash collateral requirements for the types of derivative instruments we use to hedge and otherwise manage our financial risks related to volatility in oil, gas, and NGL commodity prices.

Hedging is an important part of our financial risk management program. We have a Board-approved financial risk management policy governing our hedging practices. 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. 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. 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 when hedges are partially ineffective at offsetting the fluctuations in cash flow due to changes in the spot price for oil, natural gas, and NGLs. We recognized $5.7 million in non-cash unrealized derivative loss in the third quarter of 2010. The value of our hedge portfolio stayed relatively static from June 30, 2010, through September 30, 2010. Our hedge position was $13.7 million net asset at the end of the second quarter of 2010 compare with a $6.5 million net asset at the end of the third quarter of 2010. Corresponding changes are reflected in accumulated other comprehensive income on the consolidated balance sheets and unrealized derivative (gain) loss on the statement of operations.

Third Quarter 2010 Highlights

Operational activities. During the third quarter, we had between ten and twelve operated drilling rigs running company-wide. The thrust of our operated drilling activities this year has been focused on oil and NGL-rich gas programs and selected projects of potential strategic importance to us. Additionally, our operating partners have increased their levels of activity in oil and NGL-rich gas plays.

In the Eagle Ford shale in South Texas, we continued to operate two drilling rigs on our acreage during the third quarter. Our focus was on drilling in areas with higher BTU gas content and higher condensate yields. We have continued to test different ways to complete these wells with the objective of optimizing our future development potential. We have been encouraged with the results in the operated portion of the play and has been working to increase the pace of development on our acreage. Securing infrastructure to transport and process production from the Eagle Ford has been an issue we have worked to address over the last year, particularly in recent months. During the third quarter we entered into a gas services agreement whereby we committed a significant amount of production from the Eagle Ford to a ten-year transportation and processing arrangement beginning in 2011. This agreement has shortfall penalties in the event we are unable to deliver the committed volumes of gas. We have also recently committed to two new-build drilling rigs and have extended the contracts on two additional rigs to support our activity levels for the next several years. We continue to explore other arrangements to address the required drilling, completion, and infrastructure necessary to accelerate this program. Please refer to Note 6 Commitments and Contingencies under Part I, Item 1 of this report for additional discussion concerning our new agreements. On our outside-operated acreage in the Eagle Ford, our operating partner had six rigs running at quarter-end, which was consistent with the rig count at the end of the second quarter. This outside-operated acreage has limited infrastructure to support the development of the play. As a result we plan to participate in the construction of infrastructure with our partner. The increase in partner-operated rigs and the infrastructure build-out have resulted in higher capital expenditures in this program than we initially planned for at the beginning of the year.

We operated an average of two drilling rigs in the Williston Basin during the third quarter of the year, both of which were focused on Bakken and Three Forks drilling. Our results in this program continue to meet or exceed our expectations. Elsewhere in the Rocky Mountain region, we began drilling our second operated horizontal well targeting the Niobrara formation in southeastern Wyoming. Interest in the Niobrara formation increased significantly during the first nine months of 2010 based on positive field reports coming out of the play. Our early results from this exploratory program have been encouraging.

In our Mid-Continent region, we operated an average of two drilling rigs in our Granite Wash program in western Oklahoma. Our acreage position is held by production and we believe the potential from this emerging program could be significant. We also operated a rig in the Woodford shale in the Arkoma Basin during the third quarter, which focused primarily on drilling sections of our acreage with richer natural gas.

The Permian region ran two operated rigs in the third quarter, focusing on Wolfberry tight oil targets. In our operated Haynesville shale program, we had two drilling rigs operating in the play for most of the quarter and we are currently awaiting the completion of several wells.

Marketing of non-core properties. In the third quarter of 2010, we began marketing two divestiture packages that include non-core properties in our Rocky Mountain, Mid-Continent, and Permian regions. The non-core properties being marketed also include all of our Marcellus shale assets in North Central Pennsylvania. Please refer to Note 3 Divestitures and Assets Held for Sale, in Part I, Item 1 of this report for additional information.

Equity Compensation. On July 1, 2010, we granted awards of performance shares and restricted stock units pursuant to our long term incentive program to our various employees eligible to participate in the LTIP. The fair value associated with this grant was $25.4 million. Please refer to Note 7 Compensation Plans within Part I, Item 1 of this report for additional discussion.

Financial and production results. We recorded net income for the quarter ended September 30, 2010, of $15.5 million or $0.24 per diluted share compared to third quarter 2009 results of a net loss of $4.4 million or $(0.07) per diluted share.

28

Table of Contents

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

	Mid-Continent	ArkLaTex	South Texas & Gulf Coast	Permian	Rocky Mountain	Total (1)
Third Quarter 2010 Production:						
Oil (MBbl)	56.1	16.3	281.3	417.2	818.0	1,588.9
Gas (MMcf)	8,177.3	3,131.5	4,282.2	1,099.5	1,230.7	17,921.2
Equivalent (MMCFE)	8,514.2	3,229.0	5,970.0	3,602.7	6,138.9	27,454.8
Avg. Daily Equivalents (MMCFE/d)	92.5	35.1	64.9	39.2	66.7	298.4
Relative percentage	31%	12%	22%	13%	22%	100%

(1) Totals may not add due to rounding

For the third quarter of 2010 our production growth was led by our Eagle Ford shale program. Both our operated and partner-operated programs targeting the Eagle Ford have contributed more production than originally budgeted. Please refer to *Comparison of Financial Results and Trends between the three months ended September 30, 2010, and 2009,* for additional discussion on production.

First Nine Months 2010 Highlights

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 $125.3 million. The final gain on divestiture activity related to the divestiture is approximately $65.0 million.

Sequel Divestiture. On March 12, 2010, we completed the divestiture of certain non-strategic properties located in North Dakota to Sequel Energy Partners, LP, Bakken Energy Partners, LLC, and Three Forks Energy Partners, LLC. Total cash received, before commission costs and Net Profits Plan payments, was $129.1 million. The final sale price is subject to normal post-closing adjustments and is expected to be finalized during the fourth quarter of 2010. The estimated gain on divestiture activity related to the divestiture is approximately $52.9 million and may be impacted by the forthcoming post-closing adjustments mentioned above.

Production results. The table below details the regional breakdown of our first nine months of 2010 production.

	Mid-Continent	ArkLaTex	South Texas & Gulf Coast	Permian	Rocky Mountain	Total (1)

First nine months of 2010						
Production:						
Oil (MBbl)	163.3	56.4	599.1	1,301.2	2,406.6	4,526.6
Gas (MMcf)	24,424.4	9,406.7	10,077.6	3,122.9	4,133.5	51,165.1
Equivalent (MMCFE)	25,404.3	9,745.1	13,672.2	10,930.4	18,572.9	78,324.9
Avg. Daily Equivalents (MMCFE/d)	93.1	35.7	50.1	40.0	68.0	286.9
Relative percentage	32%	12%	18%	14%	24%	100%

(1) Totals may not add due to rounding

Table of Contents

For the first nine months of 2010 our production has outperformed our expectations due to stronger than anticipated production results from our South Texas & Gulf Coast region. Please refer to the three months discussion under *Financial and production results* above and *A three-month and nine-month overview of selected production and financial information, including trends* and *Comparison of Financial Results and Trends between the nine months ended September 30, 2010, and 2009,* for additional discussion on production.

Net Profits Plan. In 2008, the Net Profits Plan was replaced with grants of performance shares and subsequently in 2009 grants of both performance shares and RSUs. Therefore, the 2007 Net Profits Plan pool was the last pool established by us. We will continue to make payments from the existing Net Profits Plan pools and will continue to make prospective adjustments to the long-term liability as necessary.

For the nine months ended September 30, 2010, the change in the value of this liability resulted in a non-cash benefit of $29.8 million compared with a $14.0 million benefit for the same period in 2009. Current year payments made or accrued as part of allocating the proceeds received from divestitures during the first nine months of 2010 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 $18.1 million and $14.1 million for the nine months ended September 30, 2010, and 2009, respectively. Additionally, the sales of oil and gas properties described above contained a number of properties included in profit pools and resulted in payments under the Net Profits Plan of $20.8 million during the first nine months of 2010. These cash payments are accounted for as a reduction of net sale proceeds and impact the gain on divestiture activity in the accompanying consolidated statements of operations. There were no significant cash payments made or accrued under the Net Profits Plan as a result of divestitures during the first nine months 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 Note 11   Fair Value Measurements in Part I, Item 1 of this report. An increasing percentage of the costs associated with the payments under the Net Profits Plan are now being allocated to general and administrative expense rather than 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 September 30, 2010, would differ by approximately $11 million. A one percentage point increase in the discount rate would decrease the liability by approximately $6 million whereas a one percentage point decrease in the discount rate would increase the liability by $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 for oil and gas properties.

Outlook for the Remainder of 2010 and for 2011

Our development program entering 2010 was focused on the drilling of oil and rich-gas projects. This decision has been reinforced as natural gas prices have been under downward pressure most of this year. We continue to shift capital away from natural gas drilling wherever possible, except for activities necessary to satisfy leasehold commitments or to test emerging resource plays. We continue to expect that our 2010 capital investment will be near $871 million, which is up from the $725 million capital investment budget that was set at the beginning of the year. We increased our forecast for capital expenditures due to

Table of Contents

our decision to accelerate activity in plays where we have been successful this year. Additionally, inflation in the cost to drill and complete wells has put upward pressure on our capital budget. We currently anticipate increasing our level of capital investment to roughly $1.0 billion in 2011 with the majority targeted toward rich-gas projects in the Eagle Ford as well as oil projects in the Williston Basin.

We will continue to operate two rigs on our Eagle Ford acreage during the fourth quarter of 2010. To support our anticipated increase in operated activity in the Eagle Ford we have committed, or are in the process of committing, to additional drilling rigs, completion services, and infrastructure. We recently have extended the drilling contracts of two rigs operating for us in the Eagle Ford and have contracted for an additional two drilling rigs, which are scheduled to be available in mid-2011. Subsequent to quarter end, we entered into an agreement which secures a portion of the completion services needed to support the aforementioned drilling fleet. We continue to negotiate with other completion providers to secure additional services. In the Williston Basin we recently successfully completed the simultaneous fracturing of three wells in the Williston Basin that we believe will help us understand how to optimize the development of our Williston assets. We are also completing our second Niobrara well and monitoring the performance of our first well in this program. We will continue to operate two rigs in our horizontal Granite Wash program with four wells planned in the fourth quarter. We expect to operate two drilling rigs in the East Texas portion of our Haynesville shale position for the remainder of 2010. Our activity level in the Haynesville has not changed significantly from what we planned at the beginning of the year, although our amount of capital investment in this play was substantially reduced as a result of the Carry and Earning Agreement we entered into in the second quarter of 2010.

We have begun to market for sale several of our non-core oil and gas properties, including all of our Marcellus shale assets. We expect that proceeds from these divestitures will help fund a portion of our anticipated 2011 capital budget. Please refer to *Sources of Cash* and *Current Credit Facility* under the Overview of Liquidity and Capital Resources section for additional discussion regarding how we anticipate to generate cash flows to fund our 2011 capital program.

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 September 30, 2010, and the immediately preceding three quarters. Additional details of per MCFE costs are presented later in this section.

	For the Three Months Ended			
	September 30, 2010	June 30, 2010	March 31, 2010	December 31, 2009
	(In millions, except production sales data)			
Production (BCFE)	27.5	25.2	25.7	26.1
Oil and gas production revenue, excluding the effects of hedging	$ 197.4	$ 175.9	$ 212.9	$ 187.6
Realized oil and gas hedge gain	$ 8.8	$ 9.3	$ 2.6	$ 13.4
Gain on divestiture activity	$ 4.2	$ 7.0	$ 121.0	$ 22.1
Lease operating expense	$ 29.0	$ 29.0	$ 30.0	$ 34.3
Transportation costs	$ 4.9	$ 5.1	$ 4.1	$ 5.2
Production taxes	$ 10.7	$ 11.1	$ 14.2	$ 13.3
DD&A	$ 83.8	$ 79.8	$ 77.8	$ 75.1
Exploration	$ 14.4	$ 14.5	$ 13.9	$ 13.4
Impairment of proved properties	$	$	$	$ 21.6
Abandonment and impairment of unproved properties	$ 1.7	$ 2.4	$ 0.9	$ 25.2
General and administrative	$ 26.2	$ 25.4	$ 23.5	$ 20.7
Change in Net Profits Plan liability	$ 4.1	$ (6.6)	$ (27.3)	$ 7.0
Unrealized derivative (gain) loss	$ 5.7	$ (2.1)	$ (7.7)	$ 3.2
Net income	$ 15.5	$ 18.1	$ 126.2	$ 1.0
Percentage change from previous quarter:				
Production (BCFE)	9%	(2)%	(2)%	(1)%
Oil and gas production revenue, excluding the effects of hedging	12%	(17)%	13%	23%
Realized oil and gas hedge gain	(5)%	258%	(81)%	(53)%
Gain on divestiture activity	(40)%	(94)%	448%	(296)%
Lease operating expense	%	(3)%	(13)%	%
Transportation costs	(4)%	24%	(21)%	(2)%
Production taxes	(4)%	(22)%	7%	48%
DD&A	5%	3%	4%	12%
Exploration	(1)%	4%	4%	(15)%
Impairment of proved properties	%	%	(100)%	N/M
Abandonment and impairment of unproved properties	(29)%	167%	(96)%	425%
General and administrative	3%	8%	14%	%
Change in Net Profits Plan liability	(162)%	(76)%	(490)%	3%
Unrealized derivative (gain) loss	(371)%	(73)%	(341)%	(22)%
Net income	(14)%	(86)%	12,520%	(123)%

Table of Contents

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

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

	For the Three Months Ended September 30, 2010	For the Three Months Ended September 30, 2009	Percent Change Between Periods	For the Nine Months Ended September 30, 2010	For the Nine Months Ended September 30, 2009	Percent Change Between Periods
Net production volumes						
Oil (MBbl)	1,589	1,528	4%	4,527	4,816	(6)%
Natural gas (MMcf)	17,921	17,211	4%	51,165	54,055	(5)%
MMCFE (6:1)	27,455	26,377	4%	78,325	82,951	(6)%
Average daily production						
Oil (Bbl per day)	17,271	16,606	4%	16,581	17,640	(6)%
Natural gas (Mcf per day)	194,796	187,076	4%	187,418	198,005	(5)%
MCFE per day (6:1)	298,422	286,711	4%	286,904	303,848	(6)%
Oil & gas production revenue (1)						
Oil production revenue	$ 102,130	$ 95,715	7%	$ 296,313	$ 261,614	13%
Gas production revenue	104,071	85,267	22%	310,586	293,963	6%
Total	$ 206,201	$ 180,982	14%	$ 606,899	$ 555,577	9%
Oil & gas production expense						
Lease operating expense	$ 29,046	$ 34,266	(15)%	$ 88,031	$ 111,117	(21)%
Transportation costs	4,877	5,393	(10)%	14,069	15,420	(9)%
Production taxes	10,683	8,975	19%	36,014	27,391	31%
Total	$ 44,606	$ 48,634	(8)%	$ 138,114	$ 153,928	(10)%
Average net realized sales price (1)						
Oil (per Bbl)	$ 64.28	$ 62.65	3%	$ 65.46	$ 54.32	21%
Natural gas (per Mcf)	$ 5.81	$ 4.95	17%	$ 6.07	$ 5.44	12%
Per MCFE Data:						
Average net realized price (1)	$ 7.51	$ 6.86	9%	$ 7.75	$ 6.70	16%
Lease operating expenses	(1.06)	(1.30)	(18)%	(1.12)	(1.34)	(16)%
Transportation costs	(0.18)	(0.20)	(10)%	(0.18)	(0.19)	(5)%
Production taxes	(0.39)	(0.34)	15%	(0.46)	(0.33)	39%
General and administrative	(0.96)	(0.79)	22%	(0.96)	(0.67)	43%
Operating profit	$ 4.92	$ 4.23	16%	$ 5.03	$ 4.17	21%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$ 3.05	$ 2.54	20%	$ 3.08	$ 2.76	12%

(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. Average daily production for the first nine months of 2010 decreased six percent to 286.9 MMCFE compared with 303.8 MMCFE for the same period in 2009, driven by reduced capital spending in 2009 and recent divestitures. Adjusting for divestitures, our average daily production from retained properties for the first nine months of 2010 increased five percent to 283.0 MMCFE compared with 270.2 MMCFE for the same period in 2009.

Changes in production volumes, oil and gas production revenues, and costs reflect the cyclical and highly volatile nature of our industry. Our average net realized price for the three months and nine months

Table of Contents

ended September 30, 2010, was $7.51 per MCFE and $7.75 per MCFE, respectively, compared with $6.86 per MCFE and $6.70 per MCFE for the respective periods of 2009. The increase in our equivalent realized price for production corresponds with stronger commodity prices in the first nine months of 2010 when compared with the same period of 2009.

Our LOE for the three months and nine months ended September 30, 2010, decreased $0.24 per MCFE to $1.06 per MCFE and decreased $0.22 per MCFE to $1.12 per MCFE, respectively, compared to the respective periods in 2009. The divestiture of non-strategic properties with meaningfully higher operating costs is the primary reason for the decline in LOE in the comparisons above. We believe that the steady increase in industry activity that we have experienced will put upward pressure on lease operating costs that we have not experienced the last few quarters. Production taxes for the three months and nine months ended September 30, 2010, increased $0.05 per MCFE to $0.39 and increased $0.13 per MCFE to $0.46 per MCFE, respectively, compared to the respective periods in 2009. Production taxes are highly correlated to pre-hedge oil and gas revenues, and stronger commodity prices have impacted results for this expense item. Transportation costs for the three months and nine months ended September 30, 2010, decreased $0.02 per MCFE to $0.18 per MCFE and decreased $0.01 per MCFE to $0.18 per MCFE, from the corresponding periods in 2009. In late 2009 we divested of non-strategic properties within our Rocky Mountain region that had higher transportation costs. Our general and administrative expense for both the three months and nine months ended September 30, 2010, was $0.96 per MCFE, compared with $0.79 per MCFE and $0.67 per MCFE for the comparable respective periods of 2009. A portion of our general and administrative expense is linked to our profitability and cash flow, 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. Our operating profit for the three months and nine months ended September 30, 2010, was $4.92 per MCFE and $5.03 per MCFE, respectively, compared with $4.23 per MCFE and $4.17 per MCFE for the comparable periods of 2009, which was an increase of $0.69, or 16 percent, and $0.86, or 21 percent, respectively.

Our depletion, depreciation, and amortization, including asset retirement obligation accretion expense, for the three months and nine months ended September 30, 2010, was $3.05 per MCFE and $3.08 per MCFE, respectively, compared with $2.54 per MCFE and $2.76 per MCFE for the comparable respective periods of 2009. Depreciation, depletion, and amortization was impacted by our divestiture of lower cost basis properties in the first quarter of 2010. Additionally, we have been impacted by higher DD&A rates in the Eagle Ford and Haynesville shales. We are incurring capital for research wells and infrastructure that will benefit future development in these plays but are currently limited in the amount of reserves that we can record to carry the costs, which results in higher per unit DD&A costs early in the lives of these plays. Our DD&A rate can also fluctuate as a result of impairments, divestitures, and changes in the mix of our production and the 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 depleted.

Please refer to *Comparison of Financial Results and Trends between the three months ended September 30, 2010, and 2009,* and *Comparison of Financial Results and Trends between the nine months ended September 30, 2010 and 2009* for additional discussion on oil and gas production expense, DD&A, and general and administrative expense.

Table of Contents

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

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

	September 30, 2010	December 31, 2009	Percent Change Between Periods
Working capital deficit	$ 172,538	$ 87,625	97 %
Long-term debt	$ 275,404	$ 454,902	(39)%
Stockholders equity	$ 1,202,451	$ 973,570	24 %

	For the Three Months Ended September 30,		Percent Change Between Periods	For the Nine Months Ended September 30,		Percent Change Between Periods
	2010	2009		2010	2009	
Basic net income (loss) per common share	$ 0.25	$ (0.07)	(457)%	$ 2.54	$ (1.61)	(258)%
Diluted net income (loss) per common share	$ 0.24	$ (0.07)	(443)%	$ 2.47	$ (1.61)	(253)%
Basic weighted-average shares outstanding	63,031	62,505	1 %	62,914	62,420	1 %
Diluted weighted-average shares outstanding	64,794	62,505	4 %	64,599	62,420	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 contingent PSAs that are 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.

Basic and diluted weighted-average common shares outstanding used in our September 30, 2010, and 2009, earnings per share calculations reflect increases in outstanding shares related to stock option exercises, ESPP shares issued, and the settlement of vested RSUs. We issued 163,348 and 33,014 shares of common stock during the nine-month periods ended September 30, 2010, and 2009, respectively, as a result of stock option exercises. The number of RSUs that vested and settled during the first nine months of 2010 and 2009 were 57,687 and 90,486, respectively.

Table of Contents

Additional Comparative Data in Tabular Form:

	Change Between the Three Months Ended September 30, 2010, and 2009	Change Between the Nine Months Ended September 30, 2010, and 2009
Increase in oil and gas production revenues, net of hedging (In thousands)	$ 25,219	$ 51,322
Components of revenue increases (decreases):		
Oil		
Realized price change per Bbl, including the effects of hedging	$ 1.63	$ 11.14
Realized price percentage change	3%	21%
Production change (MBbl)	61	(289)
Production percentage change	4%	(6)%
Natural Gas		
Realized price change per Mcf, including the effects of hedging	$ 0.86	$ 0.63
Realized price percentage change	17%	12%
Production change (MMcf)	710	(2,890)
Production percentage change	4%	(5)%

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Revenue				
Oil	50%	53%	49%	47%
Natural gas	50%	47%	51%	53%
Production				
Oil	35%	35%	35%	35%
Natural gas	65%	65%	65%	65%

Table of Contents

Information regarding the effects of oil, natural gas, and NGL hedging activity:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Oil Hedging				
Percentage of oil production hedged	46%	59%	51%	51%
Oil volumes hedged (MBbl)	738	894	2,310	2,463
Increase (decrease) in oil revenue	$ (6.8) million	$ 1.1 million	$ (23.7) million	$ 21.6 million
Average realized oil price per Bbl before hedging	$ 68.56	$ 61.93	$ 70.70	$ 49.82
Average realized oil price per Bbl after hedging	$ 64.28	$ 62.65	$ 65.46	$ 54.32
Natural Gas Hedging				
Percentage of gas production hedged (includes NGLs)	41%	43%	46%	47%
Natural gas volumes hedged (in MMBtu, includes NGLs)	8.3 million	7.8 million	26.5 million	26.8 million
Increase in gas revenue (includes effects of NGL hedges)	$ 15.6 million	$ 27.2 million	$ 44.5 million	$ 105.6 million
Average realized gas price per Mcf before hedging (includes NGLs)	$ 4.93	$ 3.37	$ 5.20	$ 3.49
Average realized gas price per Mcf after hedging (includes NGLs)	$ 5.81	$ 4.95	$ 6.07	$ 5.44

Table of Contents

Information regarding the components of exploration expense:

	For the Three Months Ended September 30, 2010	2009	For the Nine Months Ended September 30, 2010	2009
		(In millions)		
Summary of Exploration Expense				
Geological and geophysical expenses	$ 4.9	$ 6.2	$ 13.7	$ 16.9
Exploratory dry hole expense		0.1	0.3	4.8
Overhead and other expenses	9.5	9.4	28.8	27.1
Total	$ 14.4	$ 15.7	$ 42.8	$ 48.8

Comparison of Financial Results and Trends between the three months ended September 30, 2010, and 2009

Oil and gas production revenue. Average daily production increased four percent to 298.4 MMCFE for the quarter ended September 30, 2010, compared with 286.7 MMCFE for the quarter ended September 30, 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 (Decreased) (In millions)	Production Costs Increase (Decrease) (In millions)
Mid-Continent	(4.0)	8.6	1.0
ArkLaTex	(4.0)	1.4	(1.9)
South Texas & Gulf Coast	42.7	33.1	3.5
Permian	1.1	5.0	2.5
Rocky Mountain	(24.1)	(3.4)	(9.1)
Total	11.7	44.7	(4.0)

The largest regional production decrease occurred in the Rocky Mountain region as a result of our divestitures of non-strategic oil and gas assets that occurred in the fourth quarter of 2009 and first quarter of 2010. The largest production growth occurred in the South Texas & Gulf Coast region as a result of production from drilling activity in our Eagle Ford shale program. We anticipate sequential increases in production for the remainder of 2010.

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

	For the Three Months Ended September 30, 2010	2009

Realized oil price ($/Bbl)	$ 68.56	$ 61.93
Realized gas price ($/Mcf)	$ 4.93	$ 3.37
Realized equivalent price ($/MCFE)	$ 7.19	$ 5.79

The 24 percent increase in average realized prices per MCFE coupled with a four percent increase in production volumes between periods resulted in higher oil and gas revenue. We expect our realized price to trend with commodity prices.

Table of Contents

Realized oil and gas hedge gain. We recorded a net realized hedge gain of $8.8 million for the three-month period ended September 30, 2010, related to settlements on oil and gas hedges, compared with $28.3 million gain for the same period in 2009, as a result of an increase in commodity prices on a quarter-to-quarter basis. Our realized oil and gas hedge gains and losses are a function of commodity prices and the price at which production was hedged.

Gain (loss) on divestiture activity. We had a $4.2 million net gain on divestiture activity for the quarter ended September 30, 2010, related to a divestiture of non-core oil and gas properties located in our Rocky Mountain region. We recorded an $11.3 million net loss on divestiture activity for the comparable period of 2009, resulting primarily from the accounting treatment of certain assets that were classified as held for sale and were then subsequently reclassified as held and used. We are currently marketing other non-strategic oil & gas property packages, and we expect to continue to evaluate potential divestitures of non-strategic properties in future periods.

Marketed gas system revenue and expense. Marketed gas system revenue increased $1.9 million to $15.8 million for the quarter ended September 30, 2010, compared with $13.9 million for the comparable period of 2009. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased $300,000 to $14.7 million for the quarter ended September 30, 2010, compared with $14.4 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 for natural gas.

Oil and gas production expense. Total production costs for the third quarter of 2010 decreased $4.0 million, or eight percent, to $44.6 million compared with $48.6 million for the same period of 2009. Total oil and gas production costs per MCFE decreased $0.21 to $1.63 for the third quarter of 2010, compared with $1.84 for the same period in 2009. This decrease is comprised of the following:

- A $0.15 decrease in recurring LOE on a per MCFE basis reflects the sale of non-core properties in late 2009 and early 2010 of higher per unit LOE costs that resulted in lower LOE on a per unit basis quarter over quarter. We expect the various resources required to service our industry will become more sought after and harder to secure as a result of an increase in activity. We expect to see upward pressure on LOE throughout the remainder of the year.

- A $0.09 overall decrease in workover LOE on a per MCFE basis relating primarily to a decrease in workover activity in our Rocky Mountain region

- A $0.02 decrease in overall transportation cost on a per MCFE basis as a result of the divestiture of non-core properties in the Rocky Mountain region in the fourth quarter of 2009 and first quarter of 2010 that had higher transportation costs associated with them

- A $0.05 per MCFE increase in production taxes is due to the increase in pre-hedge oil and gas revenues between periods, particularly in the South Texas & Gulf Coast region.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A increased $16.8 million, or 25 percent, to $83.8 million for the three-month period ended September 30, 2010, compared with $67.0 million for the same period in 2009. The current year s DD&A per MCFE was higher when compared with the same period in 2009 due to the impact of our divestiture of lower cost basis properties in the first quarter of 2010 and production related to properties developed in a higher cost environment becoming a larger percentage of our production mix. Additionally, we have been impacted by higher DD&A rates in the Eagle Ford and Haynesville shales. We are incurring capital for research wells and infrastructure that will benefit future development in these plays but are currently limited during the early stages of these plays in the amount of reserves that we can book to carry the costs, which results in higher per unit DD&A costs early in the lives of these plays. Any future proved property

Table of Contents

impairments, divestitures, and changes in underlying proved reserve volumes will impact our DD&A expense.

Exploration. Exploration expense decreased $1.3 million, or eight percent, to $14.4 million for the three-month period ended September 30, 2010, compared with $15.7 million for the same period in 2009. Geological and geophysical expense decreased $1.3 million due to a decrease in the amount spent on seismic related to our current and emerging resource play projects. We continue to test our current resource plays and expect to maintain a modest exploratory program for new assets in future periods. Any exploratory well incapable of producing oil or natural gas in commercial quantities will be deemed an exploratory dry hole, which will impact the amount of exploration expense we record.

Abandonment and impairment of unproved properties. Abandonment and impairment of unproved properties decreased 64 percent to $1.7 million for the three months ended September 30, 2010, compared with $4.8 million for the comparable period in 2009. Fewer dollars were available in 2009 to extend lease or drill test wells as a result of the economic conditions early in the year. We generally expect abandonments and impairments of unproved properties to be more likely to occur in periods of low commodity prices, since fewer dollars will be available for exploratory and development efforts.

General and administrative. General and administrative expense increased $5.4 million or 26 percent to $26.2 million for the three months ended September 30, 2010, compared with $20.8 million for the comparable period of 2009. On a per unit basis, G&A expense increased $0.17 to $0.96 per MCFE for the third quarter of 2010 compared to $0.79 per MCFE for the same three-month period in 2009.

General and administrative expense increased due to a $3.4 million increase in base compensation, cash bonus, and long-term incentive compensation expense for the three months ended September 30, 2010, compared with the same period in 2009. The increase in cash bonus and long-term incentive compensation expense reflects compensation expense associated with the PSAs granted in the third quarter of 2010, as well as the improvement in our performance and the anticipated achievement of various performance criteria, established by our Compensation Committee.

Additionally, G&A expense increased as a result of a $2.9 million decrease in COPAS overhead reimbursements, caused by a decrease in our operated well count resulting from our recent divestiture efforts, and a $1.3 million decrease in cash payments accrued under the Net Profits Plan. Net Profits Plan payments to plan participants were lower in the third quarter as a result of properties that were in payout in 2009 being divested of during the first quarter of 2010. We expect payments made under the Net Profits Plan to trend with commodity prices.

Change in Net Profits Plan liability. For the quarter ended September 30, 2010, this non-cash item was an expense of $4.1 million compared to an expense of $6.8 million for the same period in 2009. This non-cash charge is directly related to the change in the estimated value of the liability over the reporting period. We broadly expect the change in this liability to trend with commodity prices.

Unrealized derivative (gain) loss. We recognized a loss of $5.7 million in the third quarter of 2010 compared to a loss of $4.1 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* under Overview of the Company, Highlights, and Outlook.

Income tax expense. We recorded income tax expense of $9.3 million for the third quarter of 2010 compared to income tax benefit of $2.6 million for the third quarter of 2009 resulting in effective tax rates of 37.7 percent and 37.1 percent, respectively. The change in income tax expense is primarily the result of the differences in components of net income discussed above. The 2010 increase in effective tax rate from 2009 primarily reflects changes in the mix of the highest marginal state tax rates and the resulting effect on year-to-date net income as a result of divestiture and drilling activity in 2010, and to a lesser extent, changes

Table of Contents

in the effects of other permanent differences including the domestic production activities deduction. The current portion of our income tax expense is lower compared with the same period of 2009, as this item is being impacted by the 2010 drilling program and utilization of proceeds from 2010 non-core asset divestitures compared with a decreased drilling program in 2009 caused by lower commodity prices. These trends are expected to continue throughout the remainder of 2010 based upon our current projected capital expenditures program and commodity price outlook.

Comparison of Financial Results and Trends between the nine months ended September 30, 2010, and 2009

Oil and gas production revenue. Average daily production decreased six percent to 286.9 MMCFE for the nine months ended September 30, 2010, compared with 303.8 MMCFE for the same period in 2009. The following table presents the regional changes in our production and oil and gas revenues and costs between the two nine-month periods.

	Average Net Daily Production Added (Decreased) (MMCFE/d)	**Pre-Hedge Oil and Gas Revenue Added (In millions)**	**Production Costs Increase (Decrease) (In millions)**
Mid-Continent	(7.7)	30.5	3.0
ArkLaTex	(7.7)	4.1	(6.3)
South Texas & Gulf Coast	24.9	69.8	9.5
Permian	(2.5)	32.1	1.8
Rocky Mountain	(23.9)	21.3	(23.8)
Total	(16.9)	157.8	(15.8)

The largest regional production decrease occurred in the Rocky Mountain region and was completely offset by the regional increase in the South Texas & Gulf Coast region which is described in more detail above under *Comparison of Financial Results and Trends between the three months ended September 30, 2010, and 2009*.

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

	For the Nine Months Ended September 30,	
	2010	**2009**
Realized oil price ($/Bbl)	$ 70.70	$ 49.82
Realized gas price ($/Mcf)	$ 5.20	$ 3.49
Realized equivalent price ($/MCFE)	$ 7.48	$ 5.16

The combination of a 45 percent increase in average realized prices offset by a six percent decrease in production volumes between periods resulted in higher oil and gas revenue. Please refer to additional discussion under *Comparison of Financial Results and Trends between the three months ended September 30, 2010, and 2009.*

Realized oil and gas hedge gain. We recorded a net realized hedge gain of $20.8 million for the nine-month period ended September 30, 2010, related to settlements on oil and gas hedges, compared with $127.2 million gain for the same period in 2009. Our realized oil and gas hedge gains and losses are a function of commodity prices and the price at which production was hedged.

Table of Contents

Gain (loss) on divestiture activity. We had a $132.2 million net gain on divestiture activity for the nine-month period ended September 30, 2010, compared with a $10.6 million net loss on sale for the comparable period of 2009, due primarily to the divestitures 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 divestiture activity related to the Sequel divestiture will be adjusted for normal post-closing adjustments and is expected to be finalized during the fourth quarter of 2010. Please refer to additional discussion under *Comparison of Financial Results and Trends between the three months ended September 30, 2010, and 2009.*

Marketed gas system revenue and expense. Marketed gas system revenue increased $12.5 million to $54.0 million for the nine-month period ended September 30, 2010, compared with $41.5 million for the comparable period of 2009. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased $11.2 million to $52.6 million for the nine-month period ended September 30, 2010, compared with $41.4 million for the comparable period in 2009.

Oil and gas production expense. Total production costs decreased $15.8 million, or ten percent, to $138.1 million for the first nine months of 2010 from $153.9 million in the comparable period of 2009. Total oil and gas production costs per MCFE decreased $0.10 to $1.76 for the first nine months of 2010, compared with $1.86 for the same period in 2009. This decrease is comprised of the following:

- A $0.21 decrease in recurring LOE on a per MCFE basis reflects the divestiture of higher cost non-core properties in 2010. Please refer to additional discussion under *Comparison of Financial Results and Trends between the three months ended September 30, 2010, and 2009.*

- A $0.01 decrease in overall transportation cost on a per MCFE basis was as a result of the divestiture of non-core properties in the Rocky Mountain region in late 2009 that had higher transportation costs associated with them

- A $0.01 overall decrease in workover LOE on a per MCFE basis relating to a decrease in workover activity in our Rocky Mountain region

- A $0.13 per MCFE increase in production taxes is due to the increase in pre-hedge oil and gas revenues between periods.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A increased five percent, to $241.3 million for the nine-month period ended September 30, 2010, compared with $229.1 million for the same period in 2009. DD&A expense per MCFE increased 12 percent to $3.08 for the nine-month period ended September 30, 2010, compared to $2.76 for the same period in 2009. Please refer to additional discussion under *Comparison of Financial Results and Trends between the three months ended September 30, 2010, and 2009.*

Exploration. Exploration expense decreased $6.0 million, or 12 percent, to $42.8 million for the nine-month period ended September 30, 2010, compared with $48.8 million for the same period in 2009. Exploratory dry hole expense was $4.8 million for the nine months ended

September 30, 2009, compared with $289,000 for the same period in 2010. In 2009 several wells in the ArkLaTex were deemed to be dry. Please refer to additional discussion under *Comparison of Financial Results and Trends between the three months ended September 30, 2010, and 2009.*

Impairment of proved properties. There were no proved property impairments recorded for the nine-month period ended September 30, 2010. We recorded a $153.2 million impairment of proved oil and gas properties for the comparable period in 2009, which was driven by a significant decrease in realized gas prices in the first quarter of 2009, particularly in the Mid-Continent region, and for our coalbed methane project at Hanging Woman Basin, which was divested in late 2009. In the near-term, we expect that a continued decline in natural gas commodity prices would result in proved property impairments.

Table of Contents

Abandonment and impairment of unproved properties. Abandonment and impairment of unproved properties decreased $15.3 million or 75 percent to $5.0 million for the nine months ended September 30, 2010, compared with $20.3 million for the comparable period in 2009. We experienced larger abandonments and impairments in 2009 as a result of our lower capital budget.

Impairment of materials inventory. There were no materials inventory impairments recorded for the nine-month period ended September 30, 2010. We recorded a $13.4 million impairment of materials inventory for the nine-month period ended September 30, 2009, which was caused by a decrease in the value of tubular goods and other raw materials. Impairment of materials inventory are impacted by fluctuations in materials costs environment and increases and decreases in development and exploration activity, which generally trend with commodity prices.

General and administrative. General and administrative expense increased $19.8 million or 36 percent to $75.1 million for the nine months ended September 30, 2010, compared with $55.3 million for the comparable period of 2009. On a per unit basis, G&A expense increased $0.29 to $0.96 per MCFE for the first nine months of 2010 compared to $0.67 per MCFE for the same nine-month period in 2009.

General and administrative expense increased due a $10.2 million increase in cash bonus, long-term incentive compensation, and base compensation, and a $4.1 million decrease in COPAS overhead reimbursements. Please refer to additional discussion under *Comparison of Financial Results and Trends between the three months ended September 30, 2010, and 2009.* The $3.3 million increase in Net Profits Plan payments to plan participants was the result of 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 third quarter of 2010, 18 of our 21 pools are in payout status. No additional pools are expected to reach payout in 2010.

Change in Net Profits Plan liability. Please refer to discussion under the heading *Net Profits Plan* under Overview of the Company, Highlights, and Outlook.

Unrealized derivative (gain) loss. We recognized a gain of $4.1 million for the nine months ended September 30, 2010, compared to a loss of $17.3 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* under Overview of the Company, Highlights, and Outlook.

Other expense. Other expense decreased $10.3 million to $2.1 million for the nine months ended September 30, 2010, compared with $12.4 million for the same period in 2009. During the first nine months of 2009, we incurred $1.5 million of expense related to the assignment of a drilling rig contract in our Rocky Mountain region. We also incurred an additional loss related to hurricanes of $8.3 million for the nine months ended September 30, 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. Income tax expense totaled $96.7 million for the nine-month period of 2010 compared to an income tax benefit of $61.6 million for the same period of 2009 resulting in effective tax rates of 37.7 percent and 38.0 percent, respectively. The change in income tax expense is the result of the gains from 2010 divestitures and our 2009 loss before income taxes. The 2010 decrease in effective tax rate from 2009 reflects changes in the impact of other permanent differences including the domestic production activities deduction partially offset by an increase related to the mix of the highest marginal state tax rates resulting from divestiture and drilling activity in 2010. The current portion of our tax expense is greater in 2010 compared to 2009 due to the impact of our non-core asset divestitures in 2010 and the estimated impact of our projected capital expenditures drilling program at September 30, 2010.

Table of Contents

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 from the Rocky Mountain oil and other non-core asset divestiture packages, to fund the majority of our exploration and development budget for 2010. We will rely on our credit facility to fund any remaining balance of our capital program for the year. Accordingly, we do not expect to access the capital markets in 2010. Given the size of our commitments associated with our existing inventory of potential drilling projects, our requirements for funding could increase significantly in 2011 and beyond. As a result, we may consider accessing the capital markets, and other alternatives, as we determine how to best fund our capital program. As noted we are continuing to 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, and accessing the capital and debt markets. From time to time, we may be able to enter into carrying cost funding and sharing arrangements with third parties for particular exploration and development programs. 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, natural gas, and NGLs 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.

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. In September 2010 the lending group redetermined our reserve-backed borrowing base under the credit facility at $1.1 billion. We have been provided a $678 million commitment amount by the bank group. Our credit facility agreement has a maturity date of July 31, 2012. Management believes that the current commitment is sufficient for our current 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 17 percent of the lending commitments under the credit facility. We monitor the credit environment closely and have frequent discussions with the lending group.

As of October 27, 2010, we had $639.5 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 October 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.

The following table sets forth our weighted-average credit facility debt balance and weighted-average interest rates:

Table of Contents

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
		(In millions)		
Weighted-average credit facility debt balance	$ 6.8	$ 257.7	$ 43.9	$ 289.0
Weighted-average interest rate*	9.2%	5.9%	8.4%	5.2%

* Includes the impact of our 3.50% Senior Convertible Notes.

Our weighted-average interest rates in the current and prior year include cash interest payments, cash 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 commitment fees and non-cash charges being spread across a much lower average outstanding debt 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 of not more than 3.5 to 1.0 and a current ratio, as defined by our credit agreement, of not less than 1.0 to 1.0. The unused portion of our credit facility is factored in when calculating our current ratio. As of September 30, 2010, our debt to EBITDA ratio and current ratio as defined by our credit agreement were 0.61 and 2.58, respectively. We are in compliance with all financial and non-financial covenants under our credit facility.

Uses of Cash

We use cash for the acquisition, exploration, and development of oil and gas properties, and for the payment of debt obligations, trade payables, income taxes, common stock repurchases, and stockholder dividends. In the first nine months of 2010 we spent $488.7 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, and borrowings under our credit facility. 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 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 for the remainder of 2010.

Table of Contents

Current proposals to fund the federal government 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 potential 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 nine-month periods ended September 30, 2010, and 2009. The analysis following the table should be read in conjunction with our condensed consolidated statements of cash flows in Part I, Item 1 of this report.

	For the Nine Months Ended September 30, 2010	2009	Change	Percent Change
	(In thousands)			
Net cash provided by operating activities	$ 418,360	$ 353,052	$ 65,308	18 %
Net cash used in investing activities	$ 236,360	$ 260,651	$ (24,291)	(9)%
Net cash used in financing activities	$ 185,560	$ 78,015	$ 107,545	138 %

Analysis of Cash Flow Changes Between the Nine Months Ended September 30, 2010, and September 30, 2009

Operating activities. Cash received from oil and gas production revenue, net of the realized effects of hedging, increased $30.9 million to $602.9 million for the first nine months of 2010, compared with $572.0 million for the first nine months of 2009. Additionally, cash paid for lease operating expenses decreased $33.1 million to $88.9 million for the first nine months of 2010, compared with $122.0 million for the first nine months of 2009.

Investing activities. Cash used in investing activities for the nine months ended September 30, 2010, was $236.4 million compared with $260.7 million for the same period of 2009. We received proceeds of $259.5 million from the sale of non-core properties located primarily in the Rocky Mountain region for the nine months ended September 30, 2010. There were no major divestitures for the same period in 2009. Cash outflows for capital expenditures increased by $196.2 million for the nine months ended September 30, 2010, compared with the same period in 2009. This is due to increased drilling activity as a result of more favorable commodity prices and an improved overall macro-economic environment.

Financing activities. Net repayments on our credit facility increased by $121.0 million for the nine months ended September 30, 2010, compared with the same period in 2009. We have significantly reduced our credit facility balance throughout the first nine months of 2010, but we expect borrowings to 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 Nine Months Ended September 30, 2010	2009
	(In thousands)	
Development costs (1)	$ 196,768	$ 154,978
Exploration costs	329,909	91,549
Acquisitions		
Proved properties	663	55
Unproved properties - other	35,131	20,642
Total, including asset retirement obligations (2)	$ 562,471	$ 267,224

(1) Includes capitalized interest of $1.6 million in 2010 and $1.4 million in 2009.

(2) Includes amounts relating to estimated asset retirement obligations of $3.3 million in 2010 and $672,000 in 2009.

Costs incurred for development and exploration activities during the first nine months of 2010 increased $280.2 million or 114 percent compared to the same period in 2009. This increase in capital and exploration activities reflects a stable and improving economic environment and higher cash flows available for investment provided by operating activities and divestiture proceeds.

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

Commodity Price Risk and Interest Rate Risk

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

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

Summary of Oil, Gas, and NGL Production Hedges in Place

Our oil, natural gas, and NGL derivative contracts include costless swaps 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 forecasted production. Hedging is an important part of our financial risk management program. The amount of production we hedge is driven by the amount of debt on our consolidated balance sheet and the level of capital and long-term commitments we have made. In the case of a significant acquisition of producing properties, we will consider hedging a portion of the anticipated production in order to protect the economics assumed at the time of the acquisition. As of September 30, 2010, our hedged positions of anticipated production through the second quarter of 2013 totaled approximately 5 million Bbls of oil, 42 million MMBtu of natural gas, and 2 million Bbls of NGLs. As of October 27, 2010, we have hedge contracts in place through the third quarter of 2013 for a total of approximately 7 million Bbls of anticipated crude oil production, 42 million MMBtu of anticipated natural gas production, and 2 million Bbls of anticipated NGL production.

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

The following tables describe the volumes, average contract prices, and fair values of contracts we have in place as of September 30, 2010, and October 27, 2010. We seek 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 our areas of production, and NGL derivative contracts indexed to Oil Price Information Service Mont Belvieu. As our derivative contracts contain the same index as our sales contracts, our derivative contracts are highly correlated with the underlying hedged item.

Table of Contents

Oil Contracts

Oil Swaps

Contract Period	NYMEX WTI Volumes (Bbls)	Weighted-Average Contract Price (per Bbl)	Fair Value at September 30, 2010 (Liability) (in thousands)
Fourth quarter 2010	309,000	$ 66.06	$ (4,666)
2011	1,164,000	$ 67.06	(20,325)
2012	1,514,200	$ 82.62	(6,808)
2013	294,600	$ 84.30	(1,079)
All oil swaps	3,281,800		$ (32,878)

Oil Collars

Contract Period	NYMEX WTI Volumes (Bbls)	Weighted-Average Floor Price (per Bbl)	Weighted-Average Ceiling Price (per Bbl)	Fair Value at September 30, 2010 Asset (Liability) (in thousands)
Fourth quarter 2010	344,500	$ 50.00	$ 64.91	$ (5,669)
2011	1,236,000	$ 50.00	$ 63.70	(27,813)
2012	163,700	$ 80.00	$ 100.85	316
2013	282,600	$ 80.00	$ 100.85	296
All oil collars	2,026,800			$ (32,870)

Table of Contents

Gas Contracts

Gas Swaps

Contract Period	Volumes (MMBtu)	Weighted-Average Contract Price (per MMBtu)	Fair Value at September 30, 2010 Asset (in thousands)
Fourth quarter 2010			
IF ANR OK	140,000	$ 5.97	$ 321
IF CIG	270,000	$ 5.87	620
IF El Paso	370,000	$ 6.43	1,006
IF HSC	590,000	$ 8.61	2,785
IF NGPL	430,000	$ 5.61	821
IF NNG Ventura	360,000	$ 6.34	855
IF PEPL	520,000	$ 5.92	1,175
IF Reliant	1,350,000	$ 5.71	2,693
IF TETCO STX	180,000	$ 6.23	444
NYMEX Henry Hub	840,000	$ 7.52	3,001

Table of Contents

Gas Swaps (continued)

Contract Period	Volumes (MMBtu)	Weighted-Average Contract Price (per MMBtu)	Fair Value at September 30, 2010 Asset (in thousands)
2011			
IF ANR OK	500,000	$ 6.10	957
IF CIG	1,030,000	$ 5.96	1,992
IF El Paso	1,780,000	$ 6.35	3,963
IF HSC	360,000	$ 9.01	1,732
IF NGPL	1,040,000	$ 6.09	1,992
IF NNG Ventura	1,200,000	$ 6.36	2,409
IF PEPL	1,830,000	$ 6.04	3,539
IF Reliant	4,510,000	$ 6.13	8,795
IF TETCO STX	1,420,000	$ 6.51	3,202
NYMEX Henry Hub	2,130,000	$ 6.72	4,903
2012			
IF ANR OK	360,000	$ 6.18	524
IF CIG	1,020,000	$ 5.77	1,110
IF El Paso	850,000	$ 6.04	1,049
IF NGPL	660,000	$ 6.34	1,047
IF NNG Ventura	620,000	$ 6.51	910
IF PEPL	2,730,000	$ 6.25	4,205
IF Reliant	3,540,000	$ 5.97	3,950
IF TETCO STX	660,000	$ 6.30	896
2013			
IF PEPL	1,250,000	$ 5.65	479
IF Reliant	1,290,000	$ 5.64	452
All gas swap contracts	33,830,000		$ 61,827

Table of Contents

Gas Collars

Contract Period	Volumes (MMBtu)	Weighted-Average Floor Price (per MMBtu)	Weighted-Average Ceiling Price (per MMBtu)	Fair Value at September 30, 2010 Asset (in thousands)
Fourth quarter 2010				
IF CIG	510,000	$ 4.85	$ 7.08	$ 664
IF HSC	150,000	$ 5.57	$ 7.88	253
IF PEPL	1,240,000	$ 5.31	$ 7.61	2,032
NYMEX Henry	60,000	$ 6.00	$ 8.38	124
2011				
IF CIG	1,800,000	$ 5.00	$ 6.32	2,031
IF HSC	480,000	$ 5.57	$ 6.77	634
IF PEPL	4,225,000	$ 5.31	$ 6.51	5,418
NYMEX Henry	120,000	$ 6.00	$ 7.25	195
All gas collars	8,585,000			$ 11,351

Natural Gas Liquid Contracts

Natural Gas Liquid Swaps

	Volumes (approx. Bbls)	Weighted-Average Contract Price (per Bbl)	Fair Value at September 30, 2010 Asset (Liability) (in thousands)
Fourth quarter 2010	285,000	$ 42.67	$ (545)
2011	907,000	$ 40.32	(617)
2012	492,000	$ 43.92	166
2013	84,000	$ 44.63	27
All natural gas liquid swaps*	1,768,000		$ (969)

*Natural gas liquid swaps are comprised of OPIS Mont. Belvieu LDH Propane (31%), OPIS Mont. Belvieu Purity Ethane (41%), OPIS Mont. Belvieu NON-LDH Isobutane (4%), OPIS Mont. Belvieu NON-LDH Natural Gasoline (13%), and OPIS Mont. Belvieu NON-LDH Normal Butane (11%).

52

Table of Contents

Hedge Contracts Entered into After September 30, 2010

The following table includes all hedges entered into subsequent to September 30, 2010 through October 27, 2010.

Oil Swaps

Contract Period	NYMEX WTI Volumes (Bbl)	Weighted-Average Contract Price (Per Bbl)
Fourth quarter 2010	35,100	$ 82.70
2011	275,000	$ 84.82
All oil swaps	310,100	

Oil Collars

Contract Period	NYMEX WTI Volumes (Bbls)	Weighted-Average Floor Price (per Bbl)	Weighted-Average Ceiling Price (per Bbl)
2012	503,800	$ 70.00	$ 104.25
2013	893,700	$ 70.00	$ 104.64
All oil collars	1,397,500		

Natural Gas Liquid Swaps

Contract Period	Volumes (Bbls)	Weighted-Average Contract Price (per Bbl)
Fourth Quarter 2010	27,000	$ 40.28
2011	265,000	$ 40.10
2012	150,000	$ 19.53
All natual gas liquid swaps*	442,000	

*Natural gas liquid swaps are comprised of OPIS Mont. Belvieu LDH Propane (19%), OPIS Mont. Belvieu Purity Ethane (65%), OPIS Mont. Belvieu NON-LDH Isobutane (2%), OPIS Mont. Belvieu NON-LDH Natural Gasoline (8%), and OPIS Mont. Belvieu NON-LDH Normal Butane (6%).

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

Summary of Interest Rate Risk

Market risk is estimated as the potential change in fair value resulting from an immediate hypothetical one percentage point parallel shift in the yield curve. For fixed-rate debt, interest changes affect the fair market value but do not impact results of operations or cash flows. Conversely, interest rate

Table of Contents

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 $2.0 million of floating-rate debt outstanding as of September 30, 2010. Our fixed-rate debt outstanding, net of debt discount, at this same date was $273.4 million.

Contractual Obligations

Please see Note 6   Commitments and Contingencies under Part I, Item 1 of this report for information pertaining to new operating lease obligations and through-put commitments.

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 September 30, 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

SM Energy 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, Bakken/Three Forks, 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

Table of Contents

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. On May 13, 2010, the EPA issued rules to regulate greenhouse gas emissions from large stationary sources such as power plants and oil refineries. 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 percent reduction in greenhouse gas emissions from 2005 levels by 2020, and just over an 80 percent 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

In response to the widely reported recent oil spill in the Gulf of Mexico resulting from a deepwater drilling rig explosion in April 2010, the U.S. Congress is considering a number of legislative proposals relating to the upstream oil and gas industry both onshore and offshore that could result in significant additional laws, regulations or taxes affecting our operations, including a proposal to raise or eliminate the cap on liability for oil spill cleanups under the Oil Pollution Act of 1990.

Although it is not possible at this time to predict whether proposed legislation or regulations will be adopted as initially written, if at all, or how legislation or new regulations that may be adopted would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions. Additional costs or operating restrictions associated with legislation or regulations could have a material adverse effect on our operating results and cash flows, in addition to the demand for the crude oil, natural gas, and other hydrocarbon products that we produce.

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:

Table of Contents

- *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*

- *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.*

Table of Contents

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this item is provided under the captions *Commodity Price Risk and Interest Rate Risk*, *Summary of Oil and Gas Production Hedges in Place*, and *Summary of Interest Rate Risk* in Item 2 above and is incorporated herein by reference.

ITEM 4. CONTROLS AND PROCEDURES

We maintain a system of disclosure controls and procedures that is designed to ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized, and reported within the time periods specified in the SEC s rules and forms, and to ensure that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

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

PART II. OTHER INFORMATION

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors as previously disclosed in our Form 10-K for the year ended December 31, 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 September 30, 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)
07/01/10	07/31/10	86	$ 41.14		3,072,184
08/01/10	08/31/10	8,708	$ 41.42		3,072,184
09/01/10	09/30/10		$		3,072,184
Total:		8,794	$ 41.42		3,072,184

(1) Includes 8,794 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 SM Energy 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 SM Energy 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 6. EXHIBITS

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

Exhibit	Description
10.1	SM Energy Company Form of Performance Share and Restricted Stock Unit Award Agreement as of July 1, 2010 (filed as Exhibit 10.3 to the registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, and incorporated herein by reference)
10.2	SM Energy Company Form of Performance Share and Restricted Stock Unit Award Notice as of July 1, 2010 (filed as Exhibit 10.4 to the registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, and incorporated herein by reference)
10.3****	Gas Services Agreement effective as of July 1, 2010 between SM Energy Company and Eagle Ford Gathering LLC
10.4*	SM Energy Company Employee Stock Purchase Plan, As Amended and Restated as of July 30, 2010
10.5*	SM Energy Company Cash Bonus Plan, As Amended on July 30, 2010
10.6*	Net Profits Interest Bonus Plan, As Amended by the Board of Directors on July 30, 2010
10.7*	SM Energy Company Equity Incentive Compensation Plan, As Amended as of July 30, 2010
10.8*	SM Energy Company Non-Qualified Unfunded Supplemental Retirement Plan, As Amended as of July 30, 2010
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002
32.1**	Certification pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002
99.1*	Audit Committee Pre-Approval of Non-Audit Services
101.INS***	XBRL Instance Document
101.SCH***	XBRL Schema Document
101.CAL***	XBRL Calculation Linkbase Document
101.LAB***	XBRL Label Linkbase Document
101.PRE***	XBRL Presentation Linkbase Document

---

* Filed with this report.

** Furnished with this report.

*** Furnished, not filed. Users of this data submitted electronically herewith are advised pursuant to Rule 406T of Regulation S-T that this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections.

**** Filed with this report. Certain portions of this exhibit have been redacted and are subject to a confidential treatment request filed with the Securities and Exchange Commission pursuant to Rule 24b-2 under the Securities Exchange Act of 1934.

Exhibit constitutes a management contract or compensatory plan or agreement. This document was amended on July 30, 2010 primarily to reflect the recent change in the name of the registrant from St. Mary Land & Exploration Company to SM Energy Company. There no material changes to the substantive terms and conditions in this document.

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.

	SM ENERGY COMPANY	
November 3, 2010	By:	/s/ ANTHONY J. BEST Anthony J. Best President and Chief Executive Officer
November 3, 2010	By:	/s/ A. WADE PURSELL A. Wade Pursell Executive Vice President and Chief Financial Officer
November 3, 2010	By:	/s/ MARK T. SOLOMON Mark T. Solomon Controller