SM Energy Co
Form 10-Q
November 02, 2011

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, 2011
Commission File Number 001-31539
SM ENERGY COMPANY
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	41-0518430 (I.R.S. Employer Identification No.)
1775 Sherman Street, Suite 1200, Denver, Colorado (Address of principal executive offices)	80203 (Zip Code)

(303) 861-8140
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes 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 25, 2011, the registrant had 64,000,662 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, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$29,923	$5,077
Accounts receivable	183,943	163,190
Refundable income taxes	—	8,482
Prepaid expenses and other	30,937	45,522
Derivative asset	54,698	43,491
Deferred income taxes	5,203	8,883
Total current assets	304,704	274,645
Property and equipment (successful efforts method), at cost:		
Land	1,543	1,491
Proved oil and gas properties	4,070,916	3,389,158
Less - accumulated depletion, depreciation, and amortization	(1,635,470)	(1,326,932)
Unproved oil and gas properties	107,651	94,290
Wells in progress	329,363	145,327
Materials inventory, at lower of cost or market	14,959	22,542
Oil and gas properties held for sale (note 3)	105,918	86,811
Other property and equipment, net of accumulated depreciation of $18,312 in 2011 and $15,480 in 2010	47,655	21,365
Total property and equipment, net	3,042,535	2,434,052
Other noncurrent assets:		
Derivative asset	39,891	18,841
Other noncurrent assets	69,150	16,783
Total other noncurrent assets	109,041	35,624
Total Assets	$3,456,280	$2,744,321
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$400,420	$417,654
Derivative liability	21,106	82,044
Deposit associated with oil and gas properties held for sale	2,000	2,355
Total current liabilities	423,526	502,053
Noncurrent liabilities:		
Long-term credit facility	—	48,000
3.50% Senior Convertible Notes, net of unamortized discount of $4,861 in 2011 and $11,827 in 2010	282,639	275,673
6.625% Senior Notes	350,000	—
Asset retirement obligation	73,693	69,052

Asset retirement obligation associated with oil and gas properties held for sale (note 3)	220	2,119
Net Profits Plan liability	108,489	135,850
Deferred income taxes	609,393	443,135
Derivative liability	3,184	32,557
Other noncurrent liabilities	17,383	17,356
Total noncurrent liabilities	1,445,001	1,023,742
Commitments and contingencies (note 7)		
Stockholders' equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued: 64,079,885 shares in 2011 and 63,412,800 shares in 2010; outstanding, net of treasury shares: 63,998,818 shares in 2011 and 63,310,165 shares in 2010	641	634
Additional paid-in capital	223,120	191,674
Treasury stock, at cost: 81,067 shares in 2011 and 102,635 shares in 2010	(1,544)	(423)
Retained earnings	1,371,869	1,042,123
Accumulated other comprehensive loss	(6,333)	(15,482)
Total stockholders' equity	1,587,753	1,218,526
Total Liabilities and Stockholders' Equity	$3,456,280	$2,744,321

The accompanying notes are an integral part of these condensed 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,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
Operating revenues and other income:				
Oil, gas, and NGL production revenue	$325,231	$197,354	$935,478	$586,128
Realized hedge (loss) gain (note 10)	(6,843)	8,847	(14,548)	20,771
Gain on divestiture activity (note 3)	190,728	4,184	245,662	132,183
Marketed gas system and other operating revenue	21,458	16,499	57,184	59,634
Total operating revenues and other income	530,574	226,884	1,223,776	798,716
Operating expenses:				
Oil, gas, and NGL production expense	77,753	44,606	196,907	138,114
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	123,067	83,800	343,805	241,335
Exploration	11,272	14,437	33,587	42,833
Impairment of proved properties	48,525	—	48,525	—
Abandonment and impairment of unproved properties	—	1,719	4,316	4,998
General and administrative	29,787	26,219	82,958	75,103
Change in Net Profits Plan liability (note 8)	(24,930)	4,086	(24,719)	(29,785)
Unrealized and realized derivative (gain) loss (note 10)	(128,425)	5,727	(83,872)	(4,095)
Marketed gas system and other expense	20,737	15,238	57,746	54,621
Total operating expenses	157,786	195,832	659,253	523,124
Income from operations	372,788	31,052	564,523	275,592
Nonoperating income (expense):				
Interest income	27	85	382	268
Interest expense	(9,372)	(6,339)	(33,636)	(19,469)
Income before income taxes	363,443	24,798	531,269	256,391
Income tax expense	(133,346)	(9,346)	(195,142)	(96,693)
Net income	$230,097	$15,452	$336,127	$159,698
Basic weighted-average common shares outstanding	63,904	63,031	63,665	62,914
Diluted weighted-average common shares outstanding	67,386	64,794	67,390	64,599
Basic net income per common share (note 6)	$3.60	$0.25	$5.28	$2.54
Diluted net income per common share (note 6)	$3.41	$0.24	$4.99	$2.47

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

4

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		Additional Paid-in Capital	Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
	Shares	Amount		Shares	Amount			
Balances, January 1, 2011	63,412,800	$634	$191,674	(102,635)	$(423)	$1,042,123	$ (15,482)	$ 1,218,526
Comprehensive income, net of tax:								
Net income						336,127		336,127
Reclassification to earnings							9,149	9,149
Total comprehensive income								345,276
Cash dividends, $ 0.10 per share						(6,381)		(6,381)
Issuance of common stock under Employee Stock Purchase Plan	22,373	1	1,120					1,121
Issuance of common stock upon vesting of RSUs and settlement of PSUs, net of shares used for tax withholdings, including income tax benefit of RSUs and PSUs	278,595	3	(9,969)					(9,966)
Sale of common stock, including income tax benefit of stock option exercises	366,117	3	19,624					19,627
Stock-based compensation expense			20,671	21,568	(1,121)			19,550
	64,079,885	$641	$223,120	(81,067)	$(1,544)	$1,371,869	$ (6,333)	$ 1,587,753

Balances, September 30, 2011								
Balances, January 1, 2010	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 vesting of RSUs, 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

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)
(in thousands)

	For the Nine Months Ended September 30,	
	2011	2010
Cash flows from operating activities:		
Net income	$336,127	$159,698
Adjustments to reconcile net income to net cash provided by operating activities:		
Gain on divestiture activity	(245,662)	(132,183)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	343,805	241,335
Exploratory dry hole expense	49	289
Impairment of proved properties	48,525	—
Abandonment and impairment of unproved properties	4,316	4,998
Stock-based compensation expense	19,550	19,853
Change in Net Profits Plan liability	(24,719)	(29,785)
Unrealized derivative gain	(108,020)	(4,095)
Amortization of debt discount and deferred financing costs	14,698	10,022
Deferred income taxes	164,251	85,695
Plugging and abandonment	(2,935)	(7,106)
Other	(5,952)	(3,085)
Changes in current assets and liabilities:		
Accounts receivable	(20,787)	(4,937)
Refundable income taxes	8,482	31,402
Prepaid expenses and other	14,732	512
Accounts payable and accrued expenses	(41,558)	47,123
Excess income tax benefit from the exercise of stock awards	(15,155)	(1,376)
Net cash provided by operating activities	489,747	418,360
Cash flows from investing activities:		
Net proceeds from sale of oil and gas properties	325,053	259,501
Capital expenditures	(1,081,617)	(488,684)
Acquisition of oil and gas properties	—	(685)
Other	(340)	(6,492)
Net cash used in investing activities	(756,904)	(236,360)
Cash flows from financing activities:		
Proceeds from credit facility	115,500	315,059
Repayment of credit facility	(163,500)	(501,059)
Debt issuance costs related to credit facility	(8,719)	—
Net proceeds from 6.625% Senior Notes	341,122	—
Proceeds from sale of common stock	5,593	3,116
Dividends paid	(3,181)	(3,144)
Excess income tax benefit from the exercise of stock awards	15,155	1,376
Other	(9,967)	(908)
Net cash provided by (used in) financing activities	292,003	(185,560)

Net change in cash and cash equivalents	24,846	(3,560)
Cash and cash equivalents at beginning of period	5,077	10,649
Cash and cash equivalents at end of period	$29,923	$7,089

The accompanying notes are an integral part of these condensed 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 non-cash investing and financing activities:

	For the Nine Months Ended September 30,	
	2011	2010
	(in thousands)	
Cash paid for interest	$(24,095)	$(9,091)
Net cash refunded for income taxes	$2,346	$24,949

Dividends of approximately $3.2 million have been declared by the Company's Board of Directors, but not paid, as of September 30, 2011. Dividends of approximately $3.2 million were declared by the Company's Board of Directors, but not paid, as of September 30, 2010.

As of September 30, 2011, and 2010, $271.5 million, and $133.3 million, respectively, are included as additions to oil and gas properties and accounts payable and accrued expenses. These oil and gas property additions are reflected in cash used in investing activities in the periods that the payables are settled.

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

Table of Contents

SM ENERGY COMPANY AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

Note 1 - The Company and Business

SM Energy Company ("SM Energy" or the "Company") is an independent energy company engaged in the acquisition, exploration, exploitation, development, and production of crude oil, natural gas, and natural gas liquids ("NGLs") in onshore North America, with a focus on oil and liquids-rich resource plays.

Note 2 - Basis of Presentation, Significant Accounting Policies, and Recently Issued Accounting Standards

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 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, 2010, (the "2010 Form 10-K"). In the opinion of management, all adjustments, consisting of normal recurring accruals that are considered necessary for a fair presentation of 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 its condensed consolidated financial statements, the Company evaluated subsequent events after the balance sheet date of September 30, 2011, 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 2010 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 2010 Form 10-K. As discussed in Note 10 - Derivative Financial Instruments, as of January 1, 2011, the Company elected to discontinue cash flow hedge accounting on a prospective basis.

Recently Issued Accounting Standards

In May 2011, the Financial Accounting Standards Board ("FASB") issued new fair value measurement authoritative guidance clarifying the application of fair value measurement and disclosure requirements and changes particular principles or requirements for measuring fair value. This guidance is effective for interim and annual periods beginning after December 15, 2011. The Company is currently evaluating the provisions of this guidance and assessing the impact, if any, it may have on the Company's fair value disclosures.

In June 2011, the FASB issued new authoritative guidance that states an entity that reports items of other comprehensive income has the option to present the components of net income and comprehensive income in either one continuous financial statement, or two consecutive financial statements. This guidance is effective for interim and annual periods beginning after December 15, 2011. The Company is currently evaluating the provisions of this guidance and assessing the impact it will have on the Company's comprehensive income disclosures.

Note 3 - Divestitures and Assets Held for Sale

Eagle Ford Shale Divestiture

On August 2, 2011, the Company divested of certain operated Eagle Ford shale assets located in its South Texas & Gulf Coast region. This divestiture was comprised of the Company's entire operated acreage in LaSalle County, Texas, as well as an immaterial adjacent block of its operated acreage in Dimmit County, Texas. Total cash received, before marketing costs, was approximately $226.9 million. The final sales price is subject to post-closing adjustments and is expected to be finalized in the fourth quarter of 2011. The estimated gain on this divestiture is approximately $191.4 million. The Company determined the sale did not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

Mid-Continent Divestiture

In June 2011, the Company divested of certain non-strategic Constitution Field assets located in its Mid-Continent region. Total cash received, before marketing costs and Net Profits Interest Bonus Plan (“Net Profits Plan”) payments, was approximately $35.7 million. The final sales price is subject to post-closing adjustments and is expected to be finalized during the fourth quarter of 2011. The estimated gain on this divestiture is approximately $28.4 million. The Company determined the sale did not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

Rocky Mountain Divestiture

In January 2011, the Company divested of certain non-strategic assets located in its Rocky Mountain region. Total cash received, before marketing costs and Net Profits Plan payments, was approximately $45.5 million. The final gain related to the divestiture was approximately $27.2 million. The Company determined the sale did not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

Assets Held for Sale

Assets are classified as held for sale when the Company commits to a plan to sell the assets and there is reasonable certainty the sale will take place within one year. Upon classification as held for sale, long-lived assets are no longer depreciated or depleted and a measurement for impairment is performed to expense any excess of carrying value over fair value less costs to sell. Subsequent changes to estimated fair value less the cost to sell will impact the measurement of assets held for sale for which fair value is determined to be less than the carrying value of the assets.

As of September 30, 2011, the accompanying condensed consolidated balance sheets (“accompanying balance sheets”) included $105.9 million in book value of assets held for sale, net of accumulated depletion, depreciation and amortization and a corresponding asset retirement obligation liability is also separately presented. The above assets held for sale and asset retirement obligation liability amounts include certain assets located in Pennsylvania and the Company’s gathering assets as described in Note 12 - Acquisition and Development Agreement. The Company determined these planned asset sales do not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

In July 2011, the Company entered into an agreement to divest Marcellus shale assets located in Pennsylvania that were classified as held for sale at September 30, 2011, for $80.0 million subject to closing and post-closing adjustments. The agreement has an effective date of April 1, 2011. The agreement provided the purchaser with the option of extending the agreed upon closing date from October 15, 2011, to December 14, 2011, in exchange for an additional deposit. The purchaser has exercised this option and made the additional deposit. The closing of this transaction is subject to the satisfaction of certain closing conditions, including the resolution of any title defects exceeding specified levels. There can be no assurance that this transaction will be completed in the anticipated time frame, or at all.

Note 4 - Income Taxes

Income tax expense for the nine months ended September 30, 2011, and 2010, differs from the amounts that would be provided by applying the statutory U.S. federal income tax rate to income before income taxes as a result of the estimated effect of the domestic production activities deduction, percentage depletion, research and development credits, the effect of state income taxes, and other permanent differences.

The provision for income taxes consists of the following:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Current portion of income tax expense:				
Federal	$20,699	$2,194	$29,855	$10,410
State	637	277	1,036	588
Deferred portion of income tax expense	112,010	6,875	164,251	85,695
Total income tax expense	$133,346	$9,346	$195,142	$96,693
Effective tax rate	36.7 %	37.7 %	36.7 %	37.7 %

9

Table of Contents

On a year-to-date basis, 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 from Company activities among state tax jurisdictions. Cumulative effects of state rate changes are reflected in the period legislation is enacted. Changes in the effective tax rate between periods also occur due to estimates for the domestic production activities deduction, percentage depletion, research and development credits, uncertain tax positions, valuation allowances, 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 quarterly rate can also be impacted by the proportion of income earned in reported periods.

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. In the third quarter of 2011, the Company completed a research and development credit study and filed an amended 2007 federal return to claim a credit for that year. In the first quarter of 2011, the Company received a $5.5 million refund from its 2006 tax year as a result of a net operating loss carryback claim from the 2008 tax year. In the fourth quarter of 2010, the Internal Revenue Service initiated an audit of the Company for the 2009 tax year. The audit was concluded in the second quarter of 2011 with a $110,000 decrease to the Company's total 2005 refund claim of $25.0 million. A quick refund claim of $22.9 million from 2005 was received in the third quarter of 2010.

Note 5 - Long-Term Debt

Revolving Credit Facility

The Company executed a Fourth Amended and Restated Credit Agreement on May 27, 2011. This amended revolving credit facility replaced the Company's previous facility. The Company incurred $8.7 million of deferred financing costs in association with the amended credit facility. Borrowings under the facility are secured by substantially all of the Company's proved oil and gas properties. The credit facility has a maximum loan amount of $2.5 billion, with current aggregate lender commitments of $1.0 billion, and a maturity date of May 27, 2016. On September 29, 2011, the lending group redetermined the Company's borrowing base under the credit facility at an amount of $1.4 billion, up from $1.3 billion. The borrowing base is subject to regular semi-annual redeterminations by the Company's lenders. The borrowing base redetermination process considers the value of the Company's oil and gas properties.

The Company must comply with certain financial and non-financial covenants under the terms of its credit facility agreement, including the limitation of the Company's dividends to no more than $50.0 million per year. The Company was in compliance with all financial and non-financial covenants under the credit facility as of September 30, 2011, and through the filing of this report. Interest and commitment fees are accrued based on the borrowing base utilization grid below. Eurodollar loans accrue interest at the London Interbank Offered Rate plus the applicable margin from the utilization table below, and Alternate Base Rate ("ABR") and swingline loans accrue interest at Prime plus the applicable margin from the utilization table below. Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the accompanying condensed consolidated statements of operations ("accompanying statements of operations").

Borrowing Base Utilization Grid

Borrowing Base Utilization Percentage	<25%		≥25% <50%		≥50% <75%		≥75% <90%		≥90%	
Eurodollar Loans	1.500	%	1.750	%	2.000	%	2.250	%	2.500	%
ABR Loans or Swingline Loans	0.500	%	0.750	%	1.000	%	1.250	%	1.500	%
Commitment Fee Rate	0.375	%	0.375	%	0.500	%	0.500	%	0.500	%

The Company had no outstanding borrowings under its credit facility as of September 30, 2011. The Company had $48.0 million of outstanding borrowings under its previous credit facility at December 31, 2010. The Company had $999.4 million of available borrowing capacity under its current credit facility as of September 30, 2011, and had $629.5 million of available borrowing capacity under its previous facility at December 31, 2010, when the aggregate commitment amount was $678.0 million. The Company had two letters of credit outstanding for a total of $608,000 at September 30, 2011, and had one letter of credit outstanding in the amount of $483,000 at December 31, 2010. Outstanding letters of credit reduce the amount available under the commitment amount on a dollar-for-dollar basis.

Table of Contents

6.625% Senior Notes Due 2019

On February 7, 2011, the Company issued $350.0 million in aggregate principal amount of 6.625% Senior Notes Due 2019 (the "6.625% Senior Notes"). The 6.625% Senior Notes were issued at par and mature on February 15, 2019. The Company received net proceeds of approximately $341.1 million after deducting fees of approximately $8.9 million, which will be amortized as deferred financing costs over the life of the 6.625% Senior Notes. The net proceeds were used to repay all borrowings under the Company's previous credit facility, and the remaining proceeds were used to fund the Company's ongoing capital expenditure program and general corporate purposes.

Prior to February 15, 2014, the Company may redeem up to 35 percent of the aggregate principal amount of the 6.625% Senior Notes with the net cash proceeds of one or more equity offerings at a redemption price of 106.625% of the principal amount thereof, plus accrued and unpaid interest. The Company may also redeem the 6.625% Senior Notes, in whole or in part, at any time prior to February 15, 2015, at a redemption price equal to 100% of the principal amount, plus a specified make whole premium and accrued and unpaid interest.

The Company may also redeem all or, from time to time, a portion of the 6.625% Senior Notes on or after February 15, 2015, at the prices set forth below, during the twelve-month period beginning on February 15 of the applicable year, expressed as a percentage of the principal amount redeemed, plus accrued and unpaid interest:

2015	103.313	%
2016	101.656	%
2017 and thereafter	100.000	%

The 6.625% Senior Notes are unsecured senior obligations and rank equal in right of payment with all of the Company's existing and any future unsecured senior debt and are senior in right of payment to any future subordinated debt. There are no subsidiary guarantors of the 6.625% Senior Notes. The Company is subject to certain covenants under the indenture governing the 6.625% Senior Notes that limit incurring additional indebtedness, issuing preferred stock, and making restricted payments in excess of specified amounts. The payment of dividends on the Company's common stock must comply with the restricted payment covenant; provided, however, the first $6.5 million of dividends paid each year are not restricted by this covenant. To pay any additional dividends, the Company must comply with this covenant. The Company was in compliance with all covenants under its 6.625% Senior Notes as of September 30, 2011, and through the filing of this report.

Additionally, on February 7, 2011, the Company entered into a registration rights agreement that provides holders of the 6.625% Senior Notes certain registration rights for the 6.625% Senior Notes under the Securities Act of 1933, as amended (the "Securities Act"). Pursuant to the registration rights agreement, the Company will file an exchange offer registration statement with the Securities and Exchange Commission with respect to an offer to exchange the 6.625% Senior Notes for substantially identical notes that are registered under the Securities Act. Under certain circumstances, in lieu of a registered exchange offer, the Company has agreed to file a shelf registration statement relating to the resale of the 6.625% Senior Notes. If the exchange offer is not completed on or before February 7, 2012, or the shelf registration statement, if required, is not declared effective within the time periods specified in the registration rights agreement, then the Company has agreed to pay additional interest with respect to the 6.625% Senior Notes in an amount not to exceed one percent of the principal amount of the 6.625% Senior Notes until the exchange offer is completed or the shelf registration statement is declared effective.

3.50% Senior Convertible Notes Due 2027

On April 4, 2007, the Company issued $287.5 million in aggregate principal amount of 3.50% Senior Convertible Notes Due 2027 (the "3.50% Senior Convertible Notes"). The 3.50% Senior Convertible Notes mature on April 1, 2027, unless they are converted prior to maturity, redeemed, or purchased by the Company.

Holders of the 3.50% Senior Convertible Notes may elect to surrender all or a portion of their 3.50% Senior Convertible Notes for conversion under certain circumstances, including during a calendar quarter if the closing price of the Company’s common stock was more than 130 percent of the conversion price of $54.42 per share for at least 20 trading days in the 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter. If holders elect to convert all or a portion of the 3.50% Senior Convertible Notes during a calendar quarter in which they are eligible to do so, they will receive cash, shares of the Company’s common stock, or any combination thereof as may be elected by the Company under the indenture for the 3.50% Senior Convertible Notes. As of December 31, 2010, the 3.50% Senior Convertible Notes were not convertible. The closing price of the Company's common stock exceeded the conversion trigger price of $70.75 per share for the quarter ended March 31, 2011; however,

Table of Contents

none of the holders opted to convert their 3.50% Senior Convertible Notes during the second quarter of 2011. The closing price of the Company's common stock did not exceed the conversion trigger price for the quarters ended June 30, 2011, and September 30, 2011; therefore, the 3.50% Senior Convertible Notes were not eligible to be converted during the third quarter of 2011 and will not be eligible to be converted during the fourth quarter of 2011.

Note 6 - Earnings per Share

Basic net income per common share of stock is calculated by dividing net income available to common stockholders by the basic weighted-average common shares outstanding for the respective period. The Company’s earnings per share calculations reflect the impact of any repurchases of shares of common stock made by the Company.

Diluted net income per common share of stock is calculated by dividing adjusted net income by the number of diluted weighted-average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist of unvested restricted stock units (“RSUs”), in-the-money outstanding options to purchase the Company’s common stock, contingent Performance Share Awards ("PSAs") and contingent Performance Stock Units, and shares into which the 3.50% Senior Convertible Notes are convertible.

Performance Stock Units are structurally the same as the previously granted PSAs (collectively known as "Performance Stock Units" or "PSUs"). PSUs represent the right to receive, upon settlement of the PSUs after completion of the three-year performance period, a number of shares of the Company’s common stock that may range from zero to two times the number of PSUs granted on the award date. The number of potentially dilutive shares related to PSUs 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 PSUs, please refer to Note 8 - Compensation Plans under the heading Performance Stock Units Under the Equity Incentive Compensation Plan.

The Company’s 3.50% Senior Convertible Notes have a net-share settlement right giving the Company the option to irrevocably elect, by notice to the trustee under the indenture for the notes, to settle the Company’s obligation to deliver shares of the Company’s common stock, in the event that holders of the notes elect to convert all or a portion of their notes, by delivering cash in an amount equal to each $1,000 principal amount of notes surrendered for conversion and, if applicable, at the Company’s option, 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. For accounting purposes, the treasury stock method is used to measure the potentially dilutive impact of shares associated with this conversion feature. Shares of the Company’s common stock traded at a quarterly average closing price exceeding the $54.42 conversion price for the three and nine-month periods ended September 30, 2011, making them dilutive for those respective periods. The 3.50% Senior Convertible Notes were not dilutive for the three and nine-month periods ended September 30, 2010.

The treasury stock method is used to measure the dilutive impact of unvested RSUs, contingent PSUs, and in-the-money stock options.

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,	
	2011	2010	2011	2010
	(in thousands, except per share amounts)			
Net income	$230,097	$15,452	$336,127	$159,698

Basic weighted-average common shares outstanding	63,904	63,031	63,665	62,914
Add: dilutive effect of stock options, unvested RSUs, and contingent PSUs	2,062	1,763	2,589	1,685
Add: dilutive effect of 3.50% Senior Convertible Notes	1,420	—	1,136	—
Diluted weighted-average common shares outstanding	67,386	64,794	67,390	64,599
Basic net income per common share	$3.60	$0.25	$5.28	$2.54
Diluted net income per common share	$3.41	$0.24	$4.99	$2.47

Table of Contents

Note 7 - Commitments and Contingencies

During the second quarter of 2011, the Company entered into two natural gas gathering and services agreements whereby it is subject to certain natural gas gathering through-put commitments for up to ten years pursuant to each contract. The Company may be required to make periodic deficiency payments for any shortfalls in delivering the minimum applicable annual or semi-annual volume commitments. In the event that no gas is delivered in accordance with the agreements, the aggregate deficiency payments will total approximately $726.2 million as of September 30, 2011. If a shortfall in the minimum volume commitment arises, the Company can arrange for third party gas to be delivered into the applicable gathering system and applied to the Company's minimum commitment.

During the first quarter of 2011, the Company entered into a hydraulic fracturing services contract. The total commitment is $180.0 million over a two-year term commencing January 1, 2011. As of September 30, 2011, the remaining commitment was $112.5 million. However, the Company's liability in the event of early termination of this contract without cause is not to exceed $24.0 million. In the event of early termination of this contract with cause there is no termination fee.

The Company is subject to litigation and claims that have arisen in the ordinary course of its business. The Company accrues for such items when a liability is probable and the amount can be reasonably estimated. The Company currently has no such accruals. In the opinion of management, any adverse results in any such pending litigation and claims will not have a material effect on the results of operations, the financial position, or cash flows of the Company.

The Company is currently a defendant in litigation where the plaintiffs claim an aggregate overriding royalty interest of 7.46875 percent in production from approximately 22,000 of the Company's net acres in the Eagle Ford shale play in South Texas. The plaintiffs seek to quiet title to their claimed overriding royalty interest and seek the recovery of unpaid overriding royalty interest proceeds allegedly due. The Texas District Court issued an order granting plaintiffs' motion for summary judgment, but the Company believes that the summary judgment order is incorrect under the governing agreements and applicable law, and the Company intends to appeal and continue to contest the claim. The court entered judgment against all defendants awarding the plaintiffs damages of approximately $5.1 million. If the plaintiffs were to ultimately prevail, the overriding royalty interest would reduce the Company's net revenue interest in the affected acreage. The Company does not currently believe that an unfavorable ultimate outcome is probable, nor that if the plaintiffs prevail there would be a material effect on the financial position of the Company. Based on the Company's current view of the facts and circumstances of the case, no accrual has been made for any loss.

The Company initiated an arbitration proceeding on May 11, 2011, against Anadarko E&P Company, LP ("Anadarko"), alleging that Anadarko breached a Joint Exploration Agreement ("JEA") originally executed between Anadarko and TXCO Energy Corp. ("TXCO") in March 2008, and relating to oil and gas properties located in Maverick, Dimmitt, Webb and LaSalle Counties, Texas. The Company has been a party to the JEA since May 15, 2008. The Company asserts that Anadarko is required under the JEA to tender to the Company its proportionate share of the leasehold interests that Anadarko acquired in TXCO's bankruptcy proceeding in February 2010. The arbitration hearing related to this dispute was held in September 2011; however, the arbitration panel has not announced its determination. If the Company prevails in this matter, Anadarko could be obligated to sell to the Company an undivided interest of up to 8.333% (or up to approximately 27,000 net acres) of the total leasehold governed by the JEA in return for the Company's payment of a proportionate share of the price Anadarko paid TXCO in the bankruptcy proceeding (adjusted for revenues and expenses attributable to the purchased interest since January 1, 2010), or in the alternative, pay the Company damages in an amount to be determined by the arbitration panel.
In a separate, unrelated matter, the Company initiated an arbitration proceeding against Springfield Pipeline, LLC ("Springfield"), a wholly owned affiliate of Anadarko Petroleum Corporation, and another party in October 2011,

alleging that Springfield and the other party had unreasonably withheld or delayed consents, which are closing conditions of the Company's Acquisition and Development Agreement with Mitsui E&P Texas LP, and which are required (but are not to be unreasonably withheld or delayed) under an Agreement for the Construction, Ownership and Operation of Midstream Assets in Maverick, Dimmit, Webb and La Salle Counties, Texas, executed by the Company and Springfield and under certain other related gathering agreements. The Company has dismissed its claims in the arbitration proceeding against the other party in return for its consent. The Company has requested an expedited arbitration hearing under the commercial rules of the American Arbitration Association and is endeavoring to conclude this arbitration proceeding against Springfield during the fourth quarter of 2011.

Note 8 - Compensation Plans

Cash Bonus Plan

During the first quarters of 2011 and 2010, the Company paid $21.6 million and $7.7 million for cash bonuses earned in the 2010 and 2009 performance years, respectively. Within the general and administrative expense and exploration expense line items in

Table of Contents

the accompanying statements of operations was $3.8 million and $3.1 million of accrued cash bonus plan expense related to the specific performance year for the three-month periods ended September 30, 2011, and 2010, respectively, and $11.3 million and $9.2 million for the nine-month periods ended September 30, 2011, and 2010, respectively.

Performance Stock Units Under the Equity Incentive Compensation Plan

PSUs are the primary form of long-term equity incentive compensation for the Company. The PSU multiplier is based on the Company's performance after completion of a three-year performance period. The performance criteria for PSUs is based on a combination of the Company's annualized total shareholder return ("TSR") for the performance period and the relative measure of the Company's TSR compared with the annualized TSR of an index comprised of certain peer companies for the performance period. In addition, there are separate employment service vesting provisions. PSUs are recognized as general and administrative and exploration expense over the vesting period of the award.

Total stock-based compensation expense related to PSUs for the three-month periods ended September 30, 2011, and 2010, was $5.9 million and $5.6 million, respectively, and $14.3 million and $13.0 million for the nine-month periods ended September 30, 2011, and 2010, respectively. As of September 30, 2011, there was $31.9 million of total unrecognized compensation expense related to unvested PSUs that is being amortized through 2014.

A summary of the status and activity concerning PSUs for the nine-month period ended September 30, 2011, is presented in the following table:

	PSUs		Weighted-Average Grant-Date Fair Value
Non-vested, at January 1, 2011	1,110,666		$39.48
Granted	266,282		$91.45
Vested [(1)]	(359,671	)	$35.53
Forfeited	(125,849	)	$32.89
Non-vested, at September 30, 2011	891,428		$58.77

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

During the third quarter of 2011, the Company granted a total of 266,282 PSUs as part of its regular annual long-term equity compensation process with a fair value of $24.3 million. These PSUs will vest 1/7th on July 1, 2012, 2/7ths on July 1, 2013, and 4/7ths on July 1, 2014. During the third quarter of 2011, the Company settled 305,423 PSUs that related to awards granted in 2008 through the issuance of shares of the Company's common stock in accordance with the terms of the PSU awards. As a result, the Company issued a net of 206,468 shares of common stock associated with these grants. The remaining 98,955 shares were withheld to satisfy income and payroll tax withholding obligations that arose upon delivery of the shares underlying those PSUs.

Restricted Stock Units Under the Equity Incentive Compensation Plan

The Company grants RSUs for a portion of its annual long-term equity compensation. An RSU represents a right to receive one share of the Company's common stock to be delivered upon settlement of the RSU when it vests. Total RSU compensation expense for the three-month periods ended September 30, 2011, and 2010, was $1.6 million and $2.1 million, respectively, and $3.6 million and $5.7 million for the nine-month periods ended September 30, 2011, and 2010, respectively. As of September 30, 2011, there was $9.2 million of total unrecognized compensation expense related to unvested RSU awards that is being amortized through 2014.

Table of Contents

A summary of the status and activity concerning RSUs for the nine-month period ended September 30, 2011, is presented in the following table:

	RSUs		Weighted-Average Grant-Date Fair Value
Non-vested, at January 1, 2011	333,359		$31.16
Granted	98,952		$72.69
Vested	(105,554	)	$30.63
Forfeited	(17,270	)	$36.06
Non-vested, at September 30, 2011	309,487		$44.34

During the third quarter of 2011, the Company granted a total of 90,665 RSUs as part of its regular annual long-term equity compensation process with a fair value of $6.7 million. These RSUs will vest 1/7th on July 1, 2012, 2/7^{ths} on July 1, 2013, and 4/7^{ths} on July 1, 2014. During the first nine months of 2011, the Company settled 105,554 RSUs that related to awards granted in 2008, 2009 and 2010 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 a net of 72,127 shares of common stock associated with these grants. The remaining 33,427 shares were withheld to satisfy income and payroll tax withholding obligations that arose upon delivery of the shares underlying those RSUs.

Stock Option Grants Under Prior Stock Option Plans

The following table summarizes stock option activity for the nine months ended September 30, 2011:

	Options		Weighted-Average Exercise Price	Aggregate Intrinsic Value
Outstanding, January 1, 2011	920,765		$13.11	$42,192,057
Exercised	(366,117	)	$12.22	
Forfeited	—		$—	
Outstanding, September 30, 2011	554,648		$13.69	$26,043,950
Vested and exercisable, September 30, 2011	554,648		$13.69	$26,043,950

As of September 30, 2011, there was no unrecognized compensation expense related to stock option awards.

Director Shares

During the nine months ended September 30, 2011, and 2010, the Company issued 21,568 and 24,258 shares, respectively, of the Company's common stock held as treasury shares to the Company's non-employee directors. The shares were issued pursuant to the Company's Equity Incentive Compensation Plan. There was no compensation expense recorded for the three months ended September 30, 2011. The Company recorded $33,000 of related compensation expense for the three months ended September 30, 2010, and $1.0 million and $748,000 of related compensation expense for the nine months ended September 30, 2011, and 2010, 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 without accruing in excess of $25,000 in fair market value from such purchases for each calendar year. 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. 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 1,392,954 shares were available for issuance as of September 30, 2011. There were 22,373 and 27,456 shares issued under the ESPP during the first nine months of 2011 and 2010, respectively, with a six month minimum holding period. Shares issued under the ESPP on or after July 1, 2011, have no minimum holding period. The fair value of ESPP grants is measured at the date of grant using the Black-Scholes option-pricing model.

Table of Contents

Net Profits Plan

Under the Company's Net Profits Plan, all of the Company's oil and gas wells that were completed or acquired during a year were designated within a specific pool. Key employees recommended by senior management and designated as participants by the Compensation Committee of the Company's Board of Directors ("Board") and employed by the Company on the last day of that year became entitled to payments under the Net Profits Plan after the Company had received net cash flows returning 100 percent of all costs associated with that pool. Thereafter, ten percent of future net cash flows generated by the pool are allocated among the participants and distributed at least annually. The portion of net cash flows from a pool to be allocated among the participants increases to 20 percent after the Company has recovered 200 percent of the total costs for the pool, including payments made under the Net Profits Plan at the ten percent level. In December 2007, the Board discontinued the creation of new pools under the Net Profits Plan. As a result, 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,	
	2011	2010	2011	2010
	(in thousands)			
General and administrative expense	$4,229	$3,918	$14,820	$16,233
Exploration expense	507	638	1,569	1,896
Total	$4,736	$4,556	$16,389	$18,129

Additionally, the Company accrued or made cash payments under the Net Profits Plan of $686,000, relating to divestiture proceeds for the three months ended September 30, 2010, and $6.3 million and $20.8 million for the nine months ended September 30, 2011, and 2010, respectively. There were no cash payments made or accrued for relating to divestiture proceeds for the three months ended September 30, 2011. The cash payments are accounted for as a reduction of the gain on divestiture activity in the accompanying statements of operations.

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. If the Company allocated the change in liability to these specific functional line items, based on the current allocation of actual distributions made by the Company, such expenses or benefits would predominately be allocated to general and administrative expense. The amount that would be allocated to exploration expense is minimal in comparison. Over time, less of the amount distributed relates to prospective exploration efforts as more of the amount distributed is to employees that have terminated employment and do not provide ongoing exploration support to the Company.

Note 9 - 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").

16

Table of Contents

Components of Net Periodic Benefit Cost for Both Plans

The following table presents the components of the net periodic benefit 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,	
	2011	2010	2011	2010
	(in thousands)			
Service cost	$950	$848	$2,850	$2,544
Interest cost	296	280	888	840
Expected return on plan assets	(220)	(159)	(660)	(477)
Amortization of net actuarial loss	102	91	304	273
Net periodic benefit cost	$1,128	$1,060	$3,382	$3,180

Prior service costs are amortized on a straight-line basis over the average remaining service period of active participants. Gains and losses in excess of ten percent of the greater of the benefit obligation or the market-related value of assets are amortized over the average remaining service period of active participants.

Contributions

The Company is currently required to contribute $6.3 million to its Qualified Pension Plan for the 2011 plan year. The Company has contributed $4.3 million as of September 30, 2011.

Note 10 - Derivative Financial Instruments

To mitigate a portion of the exposure to potentially adverse market changes in oil, natural gas, and NGL prices and the associated impact on cash flows, the Company has entered into various derivative commodity contracts. The Company’s derivative contracts in place include swap and collar arrangements for oil, natural gas, and NGLs. As of September 30, 2011, and through the filing date of this report, the Company has commodity derivative contracts in place through the second quarter of 2014 for a total of approximately 9 MMBbls of anticipated crude oil production, 63 million MMBtu of anticipated natural gas production, and 2 MMBbls of anticipated NGL production.

The Company’s oil, natural gas, and NGL derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities. The Company derives internal valuation estimates that take into consideration the counterparties’ credit ratings, the Company’s credit rating, and the time value of money. These valuations are then compared to the respective counterparties’ mark-to-market statements. The pertinent factors result in an estimated exit-price that management believes provides a reasonable and consistent methodology for valuing derivative instruments. The derivative instruments utilized by the Company are not considered by management to be complex, structured, or illiquid. The oil, natural gas, and NGL derivative markets are highly active. The fair value of the commodity derivative contracts was a net asset of $70.3 million and a net liability of $52.3 million at September 30, 2011, and December 31, 2010, respectively.

Discontinuance of Cash Flow Hedge Accounting

Prior to January 1, 2011, the Company designated its commodity derivative contracts as cash flow hedges, for which unrealized changes in fair value were recorded to accumulated other comprehensive income (loss) (“AOCIL”), to the extent the hedges were effective. As of January 1, 2011, the Company elected to de-designate all of its commodity derivative contracts that had been previously designated as cash flow hedges at December 31, 2010. As a result, subsequent to December 31, 2010, the Company recognizes all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in AOCIL.

At December 31, 2010, accumulated other comprehensive loss (“AOCL”) included $18.6 million ($11.8 million, net of income tax) of unrealized losses, representing the change in fair value of the Company’s open commodity derivative contracts designated as cash flow hedges as of that balance sheet date, less any ineffectiveness recognized. As a result of discontinuing hedge accounting on January 1, 2011, such fair values at December 31, 2010 were frozen in AOCL as of the de-designation date and are reclassified into earnings as the original derivative transactions settle. During the nine months ended September 30, 2011, $14.5 million ($9.1 million, net of income tax) of derivative losses relating to de-designated commodity hedges were reclassified from

17

Table of Contents

AOCL into earnings. As of September 30, 2011, AOCL included $4.1 million ($2.7 million, net of income tax) of unrealized losses on commodity derivative contracts that had been previously designated as cash flow hedges. The Company expects to reclassify into earnings from AOCL $2.4 million, net of income tax, related to de-designated commodity derivative contracts during the next twelve months.

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

	As of September 30, 2011			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity Contracts	Current Assets	$54,698	Current Liabilities	$21,106
Commodity Contracts	Noncurrent Assets	39,891	Noncurrent liabilities	3,184
Derivatives not designated as hedging instruments		$94,589		$24,290

	As of December 31, 2010			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity Contracts	Current Assets	$43,491	Current Liabilities	$82,044
Commodity Contracts	Noncurrent Assets	18,841	Noncurrent Liabilities	32,557
Derivatives designated as hedging instruments		$62,332		$114,601

The following table summarizes the unrealized and realized gains and losses on derivative cash settlements and changes in fair value of derivative contracts as presented in the accompanying statements of operations.

	For the Three Months Ended September 30, 2011	For the Nine Months Ended September 30, 2011
	(in thousands)	
Cash settlement (gain) loss:		
Oil contracts	$1,058	$18,421
Natural gas contracts	(1,434)	(3,751)
NGL contracts	4,131	9,478
Total cash settlement loss	$3,755	$24,148
Unrealized (gain) loss on changes in fair value:		
Oil contracts	$(106,780)	$(90,629)
Natural gas contracts	(19,083)	(21,504)
NGL contracts	(6,317)	4,113
Total net unrealized (gain) on change in fair value	$(132,180)	$(108,020)
Total unrealized and realized derivative (gain)	$(128,425)	$(83,872)

18

Table of Contents

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

	Derivatives	Location on Consolidated Statement of Operations	For the Three Months Ended September 30, 2011	2010	For the Nine Months Ended September 30, 2011	2010
			(in thousands)		(in thousands)	
Amount of loss reclassified from AOCIL to realized hedge (loss) gain	Commodity Contracts	Realized hedge (loss) gain	$4,271	$2,685	$9,149	$1,903

The realized net hedge loss for the three and nine-month periods ended September 30, 2011, is comprised of realized cash settlements on commodity derivative contracts that were previously designated as cash flow hedges, whereas the realized net hedge gain for the three and nine-month periods ended September 30, 2010, is comprised of realized cash settlements on all commodity derivative contracts. Realized hedge gains or losses from the settlement of commodity derivatives previously designated as cash flow hedges are reported in the total operating revenues and other income section of the accompanying statements of operations. The Company realized a net hedge loss of $6.8 million and a net hedge gain of $8.8 million from its commodity derivative contracts for the three months ended September 30, 2011, and 2010, respectively, and a net loss of $14.5 million and a net gain of $20.8 million from its commodity derivative contracts for the nine months ended September 30, 2011, and 2010, respectively.

As noted above, effective January 1, 2011, the Company elected to de-designate all of its commodity derivative contracts that had been previously designated as cash flow hedges at December 31, 2010, and as such no new gains or losses are deferred in AOCIL at September 30, 2011. The following table details the effect of derivative instruments on AOCIL and the balance sheets (net of income tax):

	Derivatives	Location on Consolidated Balance Sheets	For the Nine Months Ended September 30, 2010	For the Year Ended December 31, 2010
			(in thousands)	
Amount of gain on derivatives recognized in AOCIL during the period (effective portion)	Commodity Contracts	AOCIL	$50,136	$16,811

The Company has no derivatives designated as cash flow hedges at September 30, 2011. The following table details the ineffective portion of derivative instruments classified as cash flow hedges on the accompanying statements of operations for the three and nine-month periods ended September 30, 2010.

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

Credit Related Contingent Features

As of September 30, 2011, and through the filing of this report, all of the Company's derivative counterparties were members of the Company's credit facility syndicate. The Company's credit facility is secured by liens on substantially all of the Company's proved oil and gas properties; therefore such counterparties do not currently require the Company to post cash collateral in instances where the Company is in a liability position under its derivative instruments. No collateral was posted as of September 30, 2011, or through the filing of this report.

Table of Contents

Convertible Note Derivative Instruments

The contingent interest provision of the 3.50% Senior Convertible Notes is an embedded derivative instrument. As of September 30, 2011, and December 31, 2010, the fair 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

The following is a listing of the Company’s financial assets and liabilities that are measured at fair value and where they are classified within the hierarchy as of September 30, 2011:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives [(a)]	$—	$94,589	$—
Proved oil and gas properties [(b)]	$—	$—	$19,113
Liabilities:			
Derivatives [(a)]	$—	$24,290	$—
Net Profits Plan [(a)]	$—	$—	$108,489

(a) This represents a financial asset or liability that is measured at fair value on a recurring basis.
(b) This represents a nonfinancial asset that is measured at fair value on a nonrecurring basis.

The following is a listing of the Company’s financial assets and liabilities that are measured at fair value on a recurring basis and where they are classified within the hierarchy as of December 31, 2010:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives	$—	$62,332	$—
Liabilities:			
Derivatives	$—	$114,601	$—
Net Profits Plan	$—	$—	$135,850

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

Table of Contents

Derivatives

The Company uses Level 2 inputs to measure the fair value of oil, natural gas, and NGL commodity derivatives. Fair values are based upon interpolated data. The Company derives internal valuation estimates taking into consideration the counterparties' credit ratings, the Company's credit rating, and the time value of money. These valuations are then compared to the respective counterparties' mark-to-market statements. The considered factors result in an estimated exit-price that management believes provides a reasonable and consistent methodology for valuing derivative instruments.

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

Valuation adjustments are necessary to reflect the effect of the Company's credit quality on the fair value of any liability position with a counterparty. This adjustment takes into account any credit enhancements, such as cash collateral 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. All of the Company's derivative counterparties are members of the Company'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 accounting authoritative guidance 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 driving net cash flows and 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 those pools currently in payout, a discount rate of 12 percent is used to calculate this liability. A discount rate of 15 percent is used to calculate the liability for pools that have not reached payout. These rates are 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 is determined using price assumptions of five one-year strip prices with the fifth year's pricing then carried out indefinitely. The average price is adjusted for realized price differentials and to include the effects of the forecasted production covered by derivatives contracts 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, 2011, would differ by approximately $9.1 million. A one percent increase in the discount rate would decrease the liability by approximately $4.8 million whereas a one percent decrease in the discount rate would increase the liability by approximately $5.3 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

Table of Contents

such, the recorded fair value is based entirely on management estimates that are described within this footnote. While some inputs to the Company's calculation of fair value on the Net Profits Plan's future payments are from published sources, others, such as the discount rate and the expected future cash flows, are derived from the Company's own calculations and estimates.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Beginning balance	$133,419	$136,420	$135,850	$170,291
Net (decrease) increase in liability [(a)]	(20,194)	9,328	(2,001)	9,110
Net settlements [(a)(b)(c)]	(4,736)	(5,242)	(25,360)	(38,895)
Transfers in (out) of Level 3	—	—	—	—
Ending balance	$108,489	$140,506	$108,489	$140,506

(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. The Company accrued or made cash payments under the Net Profits Plan relating to divestiture proceeds of $686,000 for the three months ended September 30, 2010, and $6.3 million and $20.8 million for the nine months ended September 30, 2011, and 2010, respectively. There were no cash payments made or accrued relating to divestiture proceeds for the three months ended September 30, 2011.

(c) During the first quarter of 2011, the Company made the decision to cash out several Net Profits Plan pools associated with the acquisition of Nance Petroleum Corporation in 1999, through a $2.6 million direct payment. As a result, the Company reduced its Net Profits Plan liability by that amount. There is no impact on the accompanying statements of operations for the three-month or nine-month periods ended September 30, 2011, related to these settlements.

3.50% Senior Convertible Notes

Based on the secondary market trading price of the 3.50% Senior Convertible Notes, the estimated fair value of these notes was approximately $357.2 million and $351.0 million as of September 30, 2011, and December 31, 2010, respectively. The fair value of the embedded contingent interest derivative on the 3.50% Senior Convertible Notes was immaterial as of September 30, 2011, and December 31, 2010.

6.625% Senior Notes

Based on the secondary market trading price of the 6.625% Senior Notes, the estimated fair value of these notes was approximately $351.8 million as of September 30, 2011.

Proved Oil and Gas Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs exceed the sum of the undiscounted cash flows. 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 calculation of the discount rate is a significant management estimate based on the best information available and estimated to be 12 percent for the nine months ended September 30, 2011. Management believes that the discount rate is representative of current market conditions and reflects the following factors: estimate of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. The price forecast is based on New York Mercantile Exchange ("NYMEX") strip pricing, adjusted for basis differentials, for the first five years. Future operating costs are also adjusted as deemed appropriate for these estimates.

As a result of the impairment discussed in Note 13 - Impairment of Proved Properties, the proved oil and gas properties measured at fair value within the accompanying balance sheets were $19.1 million at September 30, 2011. There were no proved oil and gas properties measured at fair value within the accompanying balance sheets at December 31, 2010.

Table of Contents

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.

There were no materials inventory measured at fair value within the accompanying balance sheets at September 30, 2011, or December 31, 2010.

Asset Retirement Obligations

The income valuation technique is utilized by the Company to determine the fair value of the asset retirement obligation liability at the point of inception by applying a credit-adjusted risk-free rate to the undiscounted expected abandonment cash flows. The credit-adjusted risk-free rate takes into account the Company’s credit risk, the time value of money, and the current economic state. 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 balance sheets at September 30, 2011, or December 31, 2010.

Refer to Note 10 - Derivative Financial Instruments for more information regarding the Company’s derivative instruments.

Note 12 - Acquisition and Development Agreement

In June 2011, the Company entered into an Acquisition and Development Agreement (the “Acquisition and Development Agreement”) with Mitsui E&P Texas LP (“Mitsui”), an indirect subsidiary of Mitsui & Co., Ltd. Pursuant to the Acquisition and Development Agreement, the Company agreed to transfer to Mitsui a 12.5 percent working interest in certain non-operated oil and gas assets representing approximately 39,000 net acres in Dimmit, LaSalle, Maverick and Webb Counties, Texas. The agreement also provides for the conveyance of one-half of the Company’s ownership in related gathering assets for the reimbursement by Mitsui of 50 percent of costs incurred on those assets and paid by the Company through the closing date. If consummated, the effective date of the transfer would be March 1, 2011. As consideration for the oil and gas interests transferred, Mitsui has agreed to pay, or carry, 90 percent of certain drilling and completion costs attributable to the Company's remaining interest in these assets following the closing of the transaction, until Mitsui has expended an aggregate $680.0 million on behalf of the Company. The Company estimates it will take three to four years to fully utilize the carry, based on the operator’s announced current drilling plans. Mitsui would also reimburse the Company for capital expenditures and other costs, net of revenues, that the Company paid and attributable to the transferred interest during the period between March 1, 2011 and the closing date. The Company would apply these reimbursed costs to the remaining ten percent of the Company’s drilling and completion costs for the affected acreage. The transaction was initially expected to close in the third quarter of 2011, subject to the satisfaction of closing conditions. Subsequent to September 30, 2011, the Company and Mitsui mutually agreed to extend the outside date for closing to December 23, 2011 to allow the parties to continue efforts to satisfy outstanding closing conditions, including obtaining required consents. There can be no assurance that this transaction will be completed in the anticipated time frame, or at all.

Note 13 - Impairment of Proved Properties

The Company recorded $48.5 million of proved property impairments on the Company's legacy James Lime assets for the three months ended September 30, 2011, due primarily to low natural gas prices. There were no impairments of proved properties in the third quarter of 2010.

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 engaged in the acquisition, exploration, exploitation, development, and production of crude oil, natural gas, and NGLs in onshore North America. Our assets include leading positions in the Eagle Ford shale and Bakken/Three Forks resource plays, as well as meaningful positions in the Granite Wash, Haynesville shale, and Woodford shale resource plays. We have built a portfolio of onshore properties in the contiguous United States primarily through early entrance into existing and emerging resource plays. This portfolio is comprised of properties with established production and reserves, prospective drilling opportunities, and unconventional resource prospects. We believe our strategy allows for stable and predictable production and reserves growth. Furthermore, by entering these plays early, we believe that we can capture larger resource potential at lower costs.

Our business strategy is to increase net asset value through attractive oil and gas investment activities, while maintaining a conservative capital structure and optimizing our capital expenditures. We focus our efforts on the exploration for and development of onshore, lower-risk resource plays in North America. We believe our inventory of resource plays is well suited for lower risk reserve and production growth due to the more predictable geologic profile of these types of assets. Furthermore, several of our assets produce significant volumes of oil and NGLs that limit our exposure to the current low natural gas price environment. Our strategy is based on the following:

- leveraging our core competencies in replicating resource play success in the drilling, completion, and development of oil, natural gas, and NGL reserves;

- focusing on resource plays with lower geologic risk and high liquids content;

- exploiting our legacy assets and optimizing our asset base;

- selectively acquiring leasehold positions in new and emerging resource plays; and

- maintaining a strong balance sheet while funding the growth of our business.

In the third quarter of 2011, we had the following financial and operational results:

- Our average daily production for the three months ended September 30, 2011, was 21.5 MBbls of oil, 281.2 MMcf of gas, and 8.6 MBbls of NGLs, for a record average equivalent production rate of 462.1 MMCFE per day, compared with 298.4 MMCFE per day for the same period in 2010. Please see additional discussion below under the caption Production Results.

- We recorded net income for the three months ended September 30, 2011, of $230.1 million or $3.41 per diluted share compared to net income for the three months ended September 30, 2010, of $15.5 million or $0.24 per diluted share.

-

Costs incurred for oil and gas producing activities for the three months ended September 30, 2011, were $440.3 million, compared with $226.4 million for the same period in 2010. Please see additional discussion below under the caption Costs Incurred.

Table of Contents

Oil, Gas, and NGL Prices

Our financial condition and the results of our operations are significantly affected by the prices we receive for oil, natural gas, and NGL production, which can fluctuate dramatically. Prior to 2011, we reported our natural gas production as a single stream of rich gas measured at the well head. As a result, we historically reported realized prices for our natural gas production for periods through December 31, 2010, that were higher than industry benchmarks due to the price uplift associated with incremental value contained in the higher BTU content of our produced gas stream. Beginning in the first quarter of 2011, we changed our reporting for natural gas volumes to show natural gas and NGL production volumes consistent with title transfer for each product. Projected rapid production growth from our rich gas assets with plant product sales contracts necessitated a change in our reporting of production volumes. Prior period production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of the NGL volumes produced in prior periods. We sell the 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. For assets where high BTU gas is sold at the wellhead, we also receive additional value for the high energy content contained in the gas stream. Our NGL production is generally sold using contracts that pay us a monthly average of the posted Oil Price Information Service Mont Belvieu daily settlement prices, adjusting for processing, transportation, and location differentials. Our crude oil and condensate are 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 product is produced, adjusted for quality, transportation, and location differentials.

The following table is a summary of commodity price data for the third quarters of 2011 and 2010 and the second quarter of 2011:

	For the Three Months Ended		
	September 30, 2011	June 30, 2011	September 30, 2010
Crude Oil (per Bbl):			
Average NYMEX price	$89.51	$102.28	$76.09
Realized price	$82.63	$97.51	$68.56
Natural Gas (per Mcf):			
Average NYMEX price	$4.12	$4.36	$4.28
Realized price	$4.52	$4.63	$4.93
Natural Gas Liquids (per Bbl):			
Average OPIS price	$61.85	$61.62	$—
Realized price	$56.10	$54.02	$—

Note: Prior year NGL production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of NGL volumes in prior periods. Please refer to additional discussion above. Average OPIS prices per barrel of NGL, historical or strip, are based on a product mix of 35% Ethane, 7% Isobutane, 11% Normal Butane, 15% Natural Gasoline and 32% Propane for all periods presented.

We expect future prices for oil, gas, and NGLs 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. Natural gas prices continue to face downward pressure as a result of high levels of drilling activity across the country. The 12-month strip prices for NYMEX WTI crude oil, NYMEX Henry Hub natural gas, and OPIS NGLs as of September 30, 2011, were $80.26 per Bbl, $4.11 per MMBTU, and $55.18 per Bbl, respectively. Comparable prices as of October 25, 2011, were $91.86 per Bbl, $3.98 per MMBTU, and $ 56.43 per Bbl, respectively.

While changes in quoted NYMEX oil and natural gas and OPIS NGL prices are generally used as a basis for comparison within our industry, the price we receive is affected by quality, energy content, location, and transportation differentials for these products. Our realized prices shown in the table above do not include the impact of cash settlements from derivative contracts, which is consistent with all prior periods reported.

Table of Contents

Derivative Activities

We use financial derivative instruments as part of our financial risk management program. We have a Board-approved financial risk management policy governing our use of derivatives. The level of our production covered by derivatives is driven by the amount of debt on our balance sheet and the level of capital commitments and long-term obligations we have in place. With the derivative contracts we have in place, we believe we have established a base cash flow stream for our future operations and partially reduced our exposure to volatility in commodity prices. Our use of collars for a portion of the derivatives allows us to participate in upward movements in oil, gas, and NGL 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, gas, and NGL derivatives, and see the caption, Summary of Oil, Gas, and NGL Derivative Contracts in Place, below.

As of January 1, 2011, we elected to de-designate all commodity derivative contracts that had previously been designated as cash flow hedges as of December 31, 2010, and to discontinue hedge accounting prospectively. Accordingly, beginning January 1, 2011, all of our derivative contracts are stated at fair value each quarter. The changes in the fair value of these contracts result in gains and losses, which are recognized immediately in earnings. For the three and nine months ended September 30, 2011, realized cash settlements from our commodity risk management program resulted in losses of $10.6 million and $38.7 million, respectively. For the three and nine months ended September 30, 2011, fluctuations in the fair value of our commodity risk management program portfolio of derivative contracts resulted in unrealized gains of $132.2 million and $108.0 million, respectively.

The following table is a reconciliation from our realized prices to our adjusted price for the commodities indicated, including the effects of derivative cash settlements for the third quarters of 2011 and 2010 and the second quarter of 2011:

	For the Three Months Ended		
	September 30, 2011	June 30, 2011	September 30, 2010
Crude Oil (per Bbl):			
Realized price	$82.63	$97.51	$68.56
Less the effects of derivative cash settlements	(7.61)	(13.11)	(4.28)
Adjusted price, including the effects of derivative cash settlements	$75.02	$84.40	$64.28
Natural Gas (per Mcf):			
Realized price	$4.52	$4.63	$4.93
Plus the effects of derivative cash settlements	0.37	0.38	0.88
Adjusted price, including the effects of derivative cash settlements	$4.89	$5.01	$5.81
Natural Gas Liquids (per Bbl):			
Realized price	$56.10	$54.02	$—
Less the effects of derivative cash settlements	(6.39)	(6.53)	—
Adjusted price, including the effects of derivative cash settlements	$49.71	$47.49	$—

Note: Prior year NGL production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of the volumes in prior periods. Please refer to additional discussion above under the caption Oil, Gas, and NGL Prices.

In July 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”), the SEC, and other regulators to establish rules and regulations to implement the new legislation. The CFTC has proposed new rules governing margin requirements for uncleared swaps entered into by non-bank swap entities, and U.S. banking regulators have proposed new rules regarding margin requirements for uncleared swaps entered into by bank swap entities. The ultimate effect of the proposed new rules and any additional regulations on our business is currently uncertain. Of particular concern to us is whether the provisions of the final rules and regulations will allow us to qualify as a non-financial, commercial end user exempt from the requirements to post margin in connection with commodity price risk management activities. Final rules and regulations on major provisions of the legislation, such as new margin requirements, are to be established through regulatory rulemaking. Although we cannot predict the ultimate outcome of these rulemakings, new rules and regulations in this area may result in increased costs and cash collateral requirements for the types of derivative instruments we use to manage our financial risks related to volatility in oil, gas, and NGL commodity prices.

Table of Contents

Third Quarter 2011 Highlights

Operational Activities. We operated an average of 12 drilling rigs company-wide during the third quarter of 2011. The focus of our operated drilling activity this year has been on oil and NGL-rich gas programs and selected natural gas projects of potential strategic importance to us. We have also participated in higher levels of outside-operated activity in oil and NGL-rich gas plays.

We had four drilling rigs running in our operated Eagle Ford shale program in South Texas at the end of the third quarter of 2011. We focused our drilling in areas with higher BTU gas content and condensate yields. We continue to test different ways to complete and space these wells to optimize future development potential. These tests include the near simultaneous fracturing of multiple wells, as well as increased density drilling to test wells spaced as close as 625 feet apart. Testing of these concepts are at various stages of maturity and we are evaluating results. In September 2011, the third party owned and operated Eagle Ford Gathering, LLC pipeline was placed into service, which increased our total wet gas takeaway capacity in the play. During the third quarter, we closed our previously announced divestiture of approximately 15,000 net operated acres in LaSalle and Dimmit Counties, Texas. This transaction closed on August 2, 2011, at which time we received approximately $226.9 million in cash proceeds, subject to post-closing adjustments. As part of this transaction, we also assigned a small portion of our committed takeaway capacity to service these assets. After the closing of this transaction we now have approximately 150,000 net operated acres in the Eagle Ford shale. During the third quarter of 2011, we announced a second transaction involving our outside-operated Eagle Ford assets. This agreement calls for the transfer of a 12.5 percent working interest in our non-operated acreage in exchange for the carry of 90 percent of our drilling and completion costs in the same acreage for an amount not to exceed $680.0 million. This agreement also provides for the divestiture of one-half of our interest in the gathering assets that service these non-operated assets in exchange for reimbursement of 50 percent of our costs on those assets. The outside closing date for this transaction has been extended to December 23, 2011, and is subject to the satisfaction of closing conditions, including the receipt of certain consents. There can be no assurance that this transaction will be completed in the anticipated time frame, or at all. If this transaction closes, we will have approximately 46,000 non-operated net acres in the Eagle Ford play and a total of 196,000 net acres in the Eagle Ford shale play. The operator of our outside-operated Eagle Ford acreage maintained a steady level of activity throughout the third quarter of 2011. During the third quarter, the operator ran ten drilling rigs and we believe the operator will operate 10 to12 drilling rigs in the fourth quarter of 2011.

We operated three drilling rigs in the Williston Basin throughout the third quarter of 2011, all of which focused on Bakken and Three Forks drilling in our Raven and Gooseneck prospects in McKenzie and Divide Counties, North Dakota. Our drilling results in these prospects have continued to meet or exceed our expectations throughout the first nine months of 2011. During the third quarter, we were able to recommence drilling and completion work as well as restart previously shut-in production related to assets affected by weather and flooding during the first half of the year. Elsewhere in the Rocky Mountain region, we continued to test the Niobrara formation in both southeastern and central Wyoming with one drilling rig. We drilled three additional test wells in the first nine months of 2011 for a total of five test wells in southeastern Wyoming, south of Silo Field, where we have approximately 26,500 net acres. In addition, during the quarter, we have initiated the drilling of our first horizontal test well targeting the Niobrara formation in the Powder River Basin where we have approximately 64,700 net acres.

In our Mid-Continent region, we operated two rigs in our Granite Wash program in the Texas Panhandle and western Oklahoma during the third quarter of 2011 to test and delineate our acreage in the play. We have approximately 34,000 net acres in the Granite Wash, which are held by production.

In our ArkLaTex region, we operated one rig in our Haynesville shale program during the third quarter of 2011, with a focus on getting the acreage to held by production status. By getting the acreage held by production, we will hold both

Haynesville and Bossier interests in the acreage with the expectation we would benefit from any future improvement in natural gas prices. We anticipate that we can drill the remaining six wells required to hold this acreage by production by the third quarter of 2012.

Our Permian region operated a one rig program during the third quarter of 2011, splitting its focus between the testing of Wolfberry down spacing and drilling Mississippian targets as part of our exploration effort.

Table of Contents

Production Results. The table below provides a regional breakdown of our production during the third quarter of 2011:

	Mid-Continent	ArkLaTex	South Texas & Gulf Coast	Permian	Rocky Mountain	Total [1]
Third Quarter 2011 Production:						
Oil (MBbl)	85.7	12.9	668.7	324.7	889.4	1,981.4
Gas (MMcf)	6,977.4	7,279.2	9,716.9	882.4	1,018.2	25,874.1
NGLs (MBbl)	37.4	22.2	721.4	3.4	8.1	792.4
Equivalent (MMCFE)	7,715.7	7,489.6	18,057.5	2,851.1	6,403.4	42,517.3
Avg. Daily Equivalents (MMCFE/d)	83.9	81.4	196.3	31.0	69.6	462.1
Relative percentage	18 %	18 %	42 %	7 %	15 %	100 %

[1] Totals may not add due to rounding.

For the third quarter of 2011, our production was led by our South Texas & Gulf Coast region due to the ongoing drilling activities in our Eagle Ford shale program. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2011, and 2010 for additional discussion on production.

Costs Incurred. The following table sets forth the costs incurred for our oil and gas activities for the third quarter of 2011:

	For the Three Months Ended September 30, 2011 (in thousands)
Development costs	$ 347,052
Facility costs	34,288
Exploration costs	31,908
Acquisitions of unproved properties	27,004
Total, including asset retirement obligations	$ 440,252

Our capital and exploration activities reflect higher cash flows provided by operating activities, divestiture proceeds, and proceeds from the issuance of our 6.625% Senior Notes.

Eagle Ford Shale Divestiture. In August 2011, we completed the divestiture of certain operated Eagle Ford shale assets located in our South Texas & Gulf Coast region. This position comprised our entire operated acreage in LaSalle County, Texas, as well as an immaterial adjacent block of our operated acreage in Dimmit County, Texas. Total cash received, before marketing costs, was approximately $226.9 million, subject to post-closing adjustments. The estimated gain on this divestiture is approximately $191.4 million.

Marcellus Divestiture. During the third quarter of 2011, we entered into an agreement to divest of our Marcellus shale assets, including associated infrastructure, located in north central Pennsylvania for $80.0 million, subject to closing and post-closing adjustments. These assets were classified as assets held for sale at September 30, 2011. The agreement has an effective date of April 1, 2011. The agreement provided the purchaser with the option of extending the agreed upon closing date from October 15, 2011, to December 14, 2011, in exchange for an additional deposit. The purchaser has exercised this option and made the additional deposit. The closing of this transaction is subject to the satisfaction of certain closing conditions, including the resolution of title defects exceeding specified levels. There can be no assurance that this transaction will be completed in the anticipated time frame, or at all.

Equity Compensation. During the third quarter of 2011, we granted 266,282 PSUs and 90,665 RSUs pursuant to our long term incentive program. Please refer to Note 8 - Compensation Plans within Part I, Item 1 of this report for additional discussion.

Credit Facility. The borrowing base for our credit facility was increased to $1.4 billion from $1.3 billion during the third quarter of 2011. The current commitment amount remains at $1.0 billion. Please refer to Overview of Liquidity and Capital Resources below for additional discussion.

Table of Contents

First Nine Months 2011 Highlights

Production Results. The table below provides a regional breakdown of our first nine months of 2011 production:

	Mid-Continent	ArkLaTex	South Texas & Gulf Coast	Permian	Rocky Mountain	Total [1]
First Nine Months of 2011 Production:						
Oil (MBbl)	246.2	46.2	1,783.6	1,000.7	2,542.0	5,618.8
Gas (MMcf)	22,026.5	20,605.5	23,120.5	2,720.5	3,041.9	71,514.8
NGLs (MBbl)	57.5	61.3	2,045.9	8.9	22.6	2,196.3
Equivalent (MMCFE)	23,848.8	21,250.5	46,097.9	8,778.4	18,429.3	118,404.8
Avg. Daily Equivalents (MMCFE/d)	87.4	77.8	168.9	32.2	67.5	433.7
Relative percentage	20 %	18 %	39 %	7 %	16 %	100 %

(1) Totals may not add due to rounding.

For the first nine months of 2011, our production was led by our South Texas & Gulf Coast region due to the ongoing drilling activities in our Eagle Ford shale program. Please refer to Comparison of Financial Results and Trends Between the Nine Months Ended September 30, 2011, and 2010 for additional discussion on production.

Costs Incurred. The following table sets forth the costs incurred for our oil and gas activities for the first nine months of 2011:

	For the Nine Months Ended September 30, 2011 (in thousands)
Development costs	$ 815,684
Facility costs	86,893
Exploration costs	133,472
Acquisitions of unproved properties	47,081
Total, including asset retirement obligations	$ 1,083,130

Our capital and exploration activities reflect higher cash flows provided by operating activities, divestiture proceeds, and proceeds from the issuance of our 6.625% Senior Notes.

Rocky Mountain Divestiture. In January 2011, we received cash, before marketing costs and Net Profits Plan payments, of $45.5 million from the completed sale of certain non-strategic assets located in our Rocky Mountain region. The final gain on this divestiture was approximately $27.2 million.

6.625% Senior Notes. In the first quarter of 2011, we issued $350.0 million in aggregate principal amount of 6.625% Senior Notes. These notes were issued at par value and have a maturity date of February 15, 2019. Net proceeds from the issued notes were approximately $341.1 million. We used a portion of the proceeds to repay the outstanding balance under our previous credit facility. Remaining proceeds were used to fund our ongoing capital expenditure program and for general corporate purposes.

Credit Facility. We completed a $2.5 billion Fourth Amended and Restated Credit Agreement on May 27, 2011. The initial borrowing base for the facility was set at $1.3 billion and was increased to $1.4 billion during the third quarter of 2011. The initial commitment amount was $1.0 billion. Please refer to Overview of Liquidity and Capital Resources below for additional discussion.

Mid-Continent Divestiture. In June 2011, we completed the divestiture of certain non-strategic Constitution Field assets located in our Mid-Continent region. Total cash received, before marketing costs and Net Profits Plan payments, was approximately $35.7 million. The final sales price is subject to post-closing adjustments and is expected to be finalized during the fourth quarter of 2011. The estimated gain on this divestiture is approximately $28.4 million.

Table of Contents

Acquisition and Development Agreement. The Acquisition and Development Agreement between us and Mitsui E&P Texas LP calls for the transfer of a 12.5 percent working interest in certain non-operated oil and gas assets representing approximately 39,000 net acres in Dimmit, LaSalle, Maverick and Webb Counties, Texas. If consummated, the agreement also provides for the conveyance of one-half of the Company's ownership in related gathering assets for reimbursement by Mitsui of 50 percent of costs incurred on those assets and paid by the Company through the closing date. The effective date of the transfer would be March 1, 2011. As consideration for the interests, Mitsui has agreed to pay, or carry, 90 percent of certain drilling and completion costs attributable to our remaining interests in these assets following the closing of the transaction, until Mitsui has expended an aggregate $680.0 million on our behalf. We estimate it will take three to four years to fully utilize the carry, based on our forecast of the operator's drilling plans. Mitsui would also reimburse us for capital expenditures and other costs, net of revenues, that we paid and attributable to the transferred interests during the period between March 1, 2011 and the closing date. We would apply these reimbursed costs to the remaining ten percent of our drilling and completion costs for the affected acreage. The transaction was expected to close in the third quarter of 2011, subject to the satisfaction of closing conditions. Subsequent to September 30, 2011, we and Mitsui mutually agreed to extend the outside date for closing to December 23, 2011 to allow the parties to continue efforts to satisfy outstanding closing conditions, including obtaining required consents. There can be no assurance that this transaction will be completed in the anticipated time frame, or at all.

Outlook for the Remainder of 2011 and 2012

We began 2011 operating two rigs on our Eagle Ford shale acreage with plans to increase our operated drilling rig count to five or six by year end. We believe we have secured the drilling rigs and completion services necessary to execute our development program in the Eagle Ford shale into the future. We believe our water rights in the Rio Grande River will meet our planned drilling and completion needs, and we are currently completing our wells with water from the Rio Grande River. Currently we are running four operated rigs on our Eagle Ford shale acreage. By the end of the first quarter of 2012, we expect to take delivery of two more walking rigs that will focus on pad drilling, which we expect these rigs to enhance operational efficiencies in our program with reduced time from spud to production and reduced well costs. Along with our pad drilling tests, we have started down spacing pilots to test approximately 625 foot spacing from the current 1,250 foot spacing. During the third quarter of 2011, additional wet gas takeaway capacity from the Eagle Ford Gathering, LLC pipeline system became available and we began transporting gas on that system in the third quarter. With regard to oil and condensate take-away capacity, we have commissioned an in-field pipeline to transport oil and condensate at two take away points at the edge of our leasehold. This line will allow for more efficient trucking of our oil and condensate. The operator of our outside-operated Eagle Ford shale properties ran an average of ten drilling rigs in the third quarter of 2011. We anticipate they will operate ten to twelve rigs on these assets in the fourth quarter of 2011 and through the end of 2012.

We expect to operate three drilling rigs for the remainder of 2011 in our Bakken/Three Forks program in the Williston Basin of North Dakota. We have approximately 205,500 net acres in the Williston Basin, of which approximately 85,000 acres are in areas we are currently developing. Our drilling has focused on our Raven and Gooseneck prospects in McKenzie and Divide Counties, North Dakota, respectively. Our plans are to continue with a three to four rig program throughout 2012. As normal operating conditions have returned following flooding in the region, we have been able to complete a significant number of wells and restore efforts to meet our original drilling and completion plan. Elsewhere in the Rocky Mountain region, we have drilled and completed all five planned exploration wells in the DJ Basin of southeastern Wyoming. We have since dropped that rig and picked up a new rig for the Powder River Basin in Wyoming, where it will be used to drill several exploratory wells targeting the Niobrara formation in that area.

In our ArkLaTex region, we plan to continue to drill wells in our operated Haynesville shale program, where we anticipate a one rig program through the third quarter of 2012. This program will focus on drilling the remaining six wells required to have all of our acreage held by production. Once we have all of our operated Haynesville acreage held by production, we plan to cease our drilling operations in this area until higher natural gas prices justify resuming activity.

We plan to run two operated drilling rigs targeting the Granite Wash formation in our Mid-Continent region for the remainder of the year. As our acreage in this play is held by production, we can adjust our activity levels quickly as circumstances warrant.

In our Permian Basin region, we plan to focus on drilling Mississippian wells and testing several exploration concepts.

Please refer to Overview of Liquidity and Capital Resources for additional discussion regarding how we anticipate funding our 2011 capital programs.

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, 2011, 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, 2011	June 30, 2011	March 31, 2011	December 31, 2010
	($ in millions, except for production data)			
Production (BCFE)	42.5	39.8	36.1	31.6
Oil, gas, and NGL production revenue	$325.2	$333.9	$276.3	$250.1
Realized hedge (loss) gain	$(6.8)	$(6.3)	$(1.4)	$2.8
Gain on divestiture activity	$190.7	$30.0	$24.9	$23.1
Lease operating expense	$40.0	$33.2	$33.1	$33.5
Transportation costs	$23.9	$16.9	$15.0	$7.1
Production taxes	$13.8	$3.3	$17.8	$16.4
DD&A	$123.1	$115.4	$105.4	$94.7
Exploration	$11.3	$9.6	$12.7	$21.1
General and administrative	$29.8	$27.3	$25.9	$31.6
Change in Net Profits Plan liability	$(24.9)	$(14.0)	$14.2	$(4.6)
Unrealized and realized derivative (gain) loss	$(128.4)	$(43.9)	$88.4	$13.0
Net income (loss)	$230.1	$124.5	$(18.5)	$37.0

Note: Prior to 2011, we have reported our natural gas production as a single stream of rich gas measured at the well head. Beginning in the first quarter of 2011, we changed our reporting for natural gas volumes to show natural gas and NGL production volumes consistent with title transfer for each product. Please refer to additional discussion above under the caption Oil, Gas, and NGL Prices.

Table of Contents

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

	For the Three Months Ended September 30, 2011	For the Three Months Ended September 30, 2010	Amount Change Between Periods	Percent Change Between Periods	For the Nine Months Ended September 30, 2011	For the Nine Months Ended September 30, 2010	Amount Change Between Periods	Percent Change Between Periods
Net production volumes								
Oil (MMBbl)	2.0	1.6	0.4	25%	5.6	4.5	1.1	24%
Natural gas (Bcf)	25.9	17.9	8.0	44%	71.5	51.2	20.3	40%
NGLs (MMBbl)	0.8	—	0.8	N/A	2.2	—	2.2	N/A
Equivalent (BCFE)	42.5	27.5	15.0	55%	118.4	78.3	40.1	51%
Average daily production								
Oil (MBbl per day)	21.5	17.3	4.2	25%	20.6	16.6	4.0	24%
Natural gas (MMcf per day)	281.2	194.8	86.4	44%	262.0	187.4	74.6	40%
NGLs (MBbl per day)	8.6	—	8.6	N/A	8.0	—	8.0	N/A
Equivalent (MMCFE per day)	462.1	298.4	163.7	55%	433.7	286.9	146.8	51%
Oil, gas, & NGL production revenue (in thousands)								
Oil production revenue	$163,735	$108,943	$54,792	50%	$497,480	$320,038	$177,442	55%
Gas production revenue	117,041	88,411	28,630	32%	322,234	266,090	56,144	21%
NGL production revenue	44,455	—	44,455	N/A	115,764	—	115,764	N/A
Total	$325,231	$197,354	$127,877	65%	$935,478	$586,128	$349,350	60%
Oil, gas, & NGL production expense (in thousands)								
Lease operating expense	$40,012	$29,046	$10,966	38%	$106,302	$88,031	$18,271	21%
Transportation costs	23,911	4,877	19,034	390%	55,759	14,069	41,690	296%
Production taxes	13,830	10,683	3,147	29%	34,846	36,014	(1,168)	(3)%
Total	$77,753	$44,606	$33,147	74%	$196,907	$138,114	$58,793	43%
Realized sales price (before derivative settlements)								
Oil (per Bbl)	$82.63	$68.56	$14.07	21%	$88.54	$70.70	$17.84	25%
Natural gas (per Mcf)	$4.52	$4.93	$(0.41)	(8)%	$4.51	$5.20	$(0.69)	(13)%
NGLs (per Bbl)	$56.10	$—	$56.10	N/A	$52.71	$—	$52.71	N/A
Per MCFE Data:								
Realized price	$7.65	$7.19	$0.46	6%	$7.90	$7.48	$0.42	6%
Lease operating expenses	(0.94)	(1.06)	0.12	(11)%	(0.90)	(1.12)	0.22	(20)%
Transportation costs	(0.56)	(0.18)	(0.38)	211%	(0.47)	(0.18)	(0.29)	161%
Production taxes	(0.33)	(0.39)	0.06	(15)%	(0.29)	(0.46)	0.17	(37)%
	(0.70)	(0.96)	0.26	(27)%	(0.70)	(0.96)	0.26	(27)%

General and administrative								
Operating profit, before the effects of derivative cash settlements	$5.12	$4.60	$0.52	11 %	$5.54	$4.76	$0.78	16 %
Derivative cash settlement	(0.25)	0.32	(0.57)	(178)%	(0.33)	0.27	(0.60)	(222)%
Operating profit, including the effects of derivative cash settlements	$4.87	$4.92	$(0.05)	(1)%	$5.21	$5.03	$0.18	4 %

32

Table of Contents

	For the Three Months Ended September 30, 2011	2010	Amount Change Between Periods	Percent Change Between Periods	For the Nine Months Ended September 30, 2011	2010	Amount Change Between Periods	Percent Change Between Periods
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$(2.89)	$(3.05)	$ 0.16	(5)%	$(2.90)	$(3.08)	$ 0.18	(6)%
Earnings per share information								
Basic net income per common share	$3.60	$0.25	$ 3.35	1,340 %	$5.28	$2.54	$ 2.74	108 %
Diluted net income per common share	$3.41	$0.24	$ 3.17	1,321 %	$4.99	$2.47	$ 2.52	102 %
Basic weighted-average shares outstanding	63,904	63,031	873	1 %	63,665	62,914	751	1 %
Diluted weighted-average shares outstanding	67,386	64,794	2,592	4 %	67,390	64,599	2,791	4 %

Note: Prior period NGL production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of NGL volumes in prior periods. Please refer to additional discussion above under the caption Oil, Gas, and NGL Prices.

We present per MCFE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends that we believe require analysis. Average daily reported production for the first nine months of 2011 increased 51 percent compared with the same period in 2010, driven primarily by the development of our Eagle Ford shale program.

Changes in production volumes, oil, gas, and NGL production revenues, and costs reflect the cyclical and highly volatile nature of our industry. Our realized price on a per MCFE basis increased six percent for both the three months and nine months ended September 30, 2011, compared to the same periods in 2010. The majority of the increase is due to a higher realized price received for oil. Please refer to discussion above under Oil, Gas, and NGL Prices for information regarding how we have changed our reporting for natural gas volumes to show post processing production volumes of natural gas and NGLs for assets where our sales contracts permit us to do so.

Our LOE on a per MCFE basis for the three and nine months ended September 30, 2011, decreased 11 percent and 20 percent, respectively, compared to the same periods in 2010. The divestiture of non-strategic properties within our Rocky Mountain and Mid-Continent regions in 2011 and Permian region in late 2010 with meaningfully higher per unit operating costs is a driver of the decline in LOE from 2010. In addition, our LOE declined on a per MCFE basis due to higher production volumes.

Production taxes on a per MCFE basis for the three and nine months ended September 30, 2011, decreased 15 percent and 37 percent, respectively, compared to the same periods in 2010. We received notification in the second quarter that wells within our Eagle Ford and Haynesville shale plays qualified for the severance tax incentive programs in Texas. As a result a sizable incentive tax rebate was recorded during the second quarter, causing a significant decrease for the nine months ended September 30, 2011. Production taxes for the three months ended September 30, 2011, decreased due to lower anticipated severance tax accruals as a result of the reduced tax rates. We expect that substantially all future operated wells to be drilled in these areas will qualify for enacted reduced tax rates. We generally expect production taxes to trend with oil, gas, and NGL revenues.

Transportation costs on a per MCFE basis for the three and nine months ended September 30, 2011, increased 211 percent and 161 percent, respectively, compared to the same periods in 2010. This is a result of increased production in our Eagle Ford shale program, where new transportation arrangements that we have entered into are resulting in higher per unit transportation costs, due to the lack of infrastructure in the emerging play. We anticipate transportation costs will increase over the remainder of the year on a per MCFE basis, as the Eagle Ford shale becomes a larger portion of our production mix.

Our general and administrative expense on a per MCFE basis for both the three and nine months ended September 30, 2011, decreased 27 percent compared to the same periods in 2010. Production increased at a faster rate than our general and administrative expense. 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 short-term incentive compensation are tied to net revenues and therefore are subject to variability. Our operating profit, including the effects of derivative cash settlements, for the three and nine months ended September 30, 2011, decreased one percent and increased four percent, respectively, compared to the same periods in 2010.

Table of Contents

Our depletion, depreciation, and amortization, including asset retirement obligation accretion expense, for the three and nine months ended September 30, 2011, decreased five percent and six percent per MCFE, respectively, compared to the same periods in 2010. The property balances between the periods presented stayed relatively constant while the reserve base increased causing the per unit DD&A rate to decrease. Our DD&A rate can 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.

Our basic and diluted earnings per share, for the three and nine months ended September 30, 2011, increased substantially compared to the same periods in 2010. The majority of this increase is due to our net income balance used to derive earnings per share, which includes a gain of approximately $191.4 million related to our divestiture of our operated acreage in LaSalle County, Texas. See Note 3 - Divestitures and Assets Held for Sale, in Part I, Item 1 of this report. Divestitures by nature are considered non-recurring by the Company and are not indicative of future activity.

Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2011, and 2010 and Comparison of Financial Results and Trends Between the Nine Months Ended September 30, 2011, and 2010 for additional discussion on oil, gas, and NGL production expense, DD&A, and general and administrative expense.

Both basic and diluted earnings per share are presented in the table above. We use the treasury stock method to account for the potential diluted earnings per share impact of unvested RSUs, contingent PSUs, in-the-money stock options, and our 3.50% Senior Convertible Notes. In-the-money stock options, unvested RSUs, and contingent PSUs were dilutive for the three and nine months ended September 30, 2011, and 2010. Basic common shares outstanding used in our September 30, 2011, and 2010 earnings per share calculations reflect increases in outstanding shares related to stock option exercises and vested RSUs. Our September 30, 2011, calculation also includes fully vested and released PSUs. We issued 366,117 and 163,348 shares of common stock during the nine-month periods ended September 30, 2011, and 2010, respectively, as a result of stock option exercises. The number of RSUs that vested and settled during the first nine months of 2011 and 2010 were 72,127 and 57,687, respectively. During the nine months ended September 30, 2011, 206,468 PSUs fully vested and settled as part of the first settlement of this type of award. For the three months and nine months ended September 30, 2011, our average stock price exceeded the conversion price of $54.42 making our 3.50% Senior Convertible Notes dilutive for our 2011 quarter-to-date and year-to-date diluted weighted-average common shares outstanding calculation. The 3.50% Senior Convertible Notes were not dilutive for the three-month and nine-month periods ended September 30, 2010. Currently, our stock price continues to trade above the $54.42 conversion price, therefore we expect our 3.50% Senior Convertible Notes to have a dilutive impact on our fourth quarter earnings per share calculation. Please refer to Note 6 - Earnings per Share in Part I, Item 1 of this report for additional discussion.

Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2011, and 2010

Oil, gas, and NGL production revenue. Average daily reported production increased 55 percent to 462.1 MMCFE for the quarter ended September 30, 2011, compared with 298.4 MMCFE for the quarter ended September 30, 2010. Please refer to the discussion above under Oil, Gas, and NGL Prices regarding how we have changed our reporting for natural gas and NGL volumes. The following table presents the regional changes in our production, oil, gas, and NGL revenues, and costs between the two quarters:

	Average Net Daily Production Added (Decreased)	Oil, Gas, & NGL Revenue Added (Decreased)	Production Costs Increase (Decrease)

	(MMCFE/d)	(in millions)	(in millions)
Mid-Continent	(8.7)	$1.6	$—
ArkLaTex	46.3	18.1	2.7
South Texas & Gulf Coast	131.4	88.5	26.9
Permian	(8.2)	(1.2)	(1.1)
Rocky Mountain	2.9	20.9	4.6
Total	163.7	$127.9	$33.1

The largest increase in production occurred in the South Texas & Gulf Coast region as a result of drilling activity in our Eagle Ford shale program. Activity in our Eagle Ford shale program continues to increase and we anticipate production from this region will continue to increase for the foreseeable future. We also saw an increase in our ArkLaTex region, as a result of strong production performance from wells drilled in our Haynesville shale program in late 2010 and early 2011.

Table of Contents

A six percent increase in the realized equivalent price per MCFE, combined with a 55 percent increase in production volumes, resulted in a substantial increase in revenue between the two periods. We expect our realized prices to trend with commodity prices.

Realized hedge (loss) gain. We recorded a net realized hedge loss of $6.8 million for the three-month period ended September 30, 2011, compared with a $8.8 million net gain for the same period in 2010. The realized net loss in 2011 is comprised of realized cash settlements on commodity derivative contracts that were previously recorded in AOCL, whereas the realized net gain in 2010 is comprised of realized cash settlements on all commodity derivative contracts. Our realized oil, gas, and NGL hedge gains and losses are a function of commodity prices at the time of settlement and the price at the time the derivative transaction was entered into.

Gain on divestiture activity. We recorded a $190.7 million net gain on divestiture activity for the quarter ended September 30, 2011, relating mainly to the divestiture of certain Eagle Ford shale oil and gas assets in our South Texas & Gulf Coast region. We recorded a $4.2 million net gain on divestiture activity for the comparable period of 2010, related to a divestiture of non-core oil and gas properties located in our Rocky Mountain region. We are currently marketing other oil and gas properties, and we will continue to evaluate properties for divestiture in the normal course of our business.

Marketed gas system revenue and expense. Marketed gas system revenue increased $6.0 million to $21.8 million for the quarter ended September 30, 2011, compared with $15.8 million for the same period of 2010. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased $4.4 million to $19.1 million for the quarter ended September 30, 2011, compared with $14.7 million for the same period of 2010. The net margin 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 realized price for natural gas.

Oil, gas, and NGL production expense. Total production costs for the third quarter of 2011 increased 74 percent, to $77.8 million compared with $44.6 million for the same period of 2010. Total oil and gas production costs per MCFE increased $0.20, or 12 percent, to $1.83 for the third quarter of 2011, compared with $1.63 for the same period in 2010. The per MCFE increase is comprised of the following:

- A $0.38 increase in overall transportation costs on a per MCFE basis is primarily a result of increased production in our Eagle Ford shale. Please refer to our transportation cost discussion under the caption A three-month and nine-month overview of selected production and financial information, including trends for additional information.

- A $0.18 decrease in recurring LOE on a per MCFE basis reflects the 2010 and early 2011 sales of non-core properties with higher per unit LOE costs.

- A $0.06 per MCFE decrease in production taxes is due to severance tax incentives within our South Texas & Gulf Coast and ArkLaTex regions. Please refer to our production tax discussion under the caption A three-month and nine-month overview of selected production and financial information, including trends for additional information.

- A $0.06 overall increase in workover LOE on a per MCFE basis relates primarily to increased workover activity in our Permian Region.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A increased $39.3 million, or 47 percent, to $123.1 million for the three-month period ended September 30, 2011, compared with $83.8 million for the same period in 2010. Please refer to our depletion, depreciation, amortization, and asset retirement obligation liability accretion comparison discussion under the caption A three-month and nine-month overview of selected production and financial information, including trends for additional information.

Table of Contents

Exploration. The components of exploration expense are summarized as follows:

	For the Three Months Ended September 30,	
	2011	2010
	(in millions)	
Geological and geophysical expenses	$0.2	$4.9
Exploratory dry hole expense	—	—
Overhead and other expenses	11.1	9.5