SM Energy Co
Form 10-Q
October 30, 2013
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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, 2013
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 þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§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 þ 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 þ	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

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

As of October 23, 2013, the registrant had 66,988,132 shares of common stock, $0.01 par value, outstanding.

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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, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$176	$5,926
Accounts receivable	278,125	254,805
Refundable income taxes	2,854	3,364
Prepaid expenses and other	10,498	30,017
Derivative asset	43,305	37,873
Deferred income taxes	10,912	8,579
Total current assets	345,870	340,564
Property and equipment (successful efforts method):		
Land	1,857	1,845
Proved oil and gas properties	5,414,842	5,401,684
Less - accumulated depletion, depreciation, and amortization	(2,418,939)	(2,376,170)
Unproved oil and gas properties	263,662	175,287
Wells in progress	301,609	273,928
Materials inventory, at lower of cost or market	14,115	13,444
Oil and gas properties held for sale net of accumulated depletion, depreciation and amortization of $539,769 in 2013 and $20,676 in 2012	400,393	33,620
Other property and equipment, net of accumulated depreciation of $27,571 in 2013 and $22,442 in 2012	203,799	153,559
Total property and equipment, net	4,181,338	3,677,197
Noncurrent assets:		
Derivative asset	28,659	16,466
Restricted cash	94,700	86,773
Other noncurrent assets	86,278	78,529
Total other noncurrent assets	209,637	181,768
Total Assets	$4,736,845	$4,199,529
LIABILITIES AND STOCKHOLDERS’ EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$601,131	$525,627
Derivative liability	22,648	8,999
Other current liabilities	6,000	6,920
Total current liabilities	629,779	541,546
Noncurrent liabilities:		
Revolving credit facility	28,000	340,000
6.625% Senior Notes Due 2019	350,000	350,000
6.50% Senior Notes Due 2021	350,000	350,000
6.50% Senior Notes Due 2023	400,000	400,000

5.0% Senior Notes Due 2024	500,000	—
Asset retirement obligation	101,650	112,912
Asset retirement obligation associated with oil and gas properties held for sale	25,339	1,393
Net Profits Plan liability	72,404	78,827
Deferred income taxes	639,000	537,383
Derivative liability	6,873	6,645
Other noncurrent liabilities	47,016	66,357
Total noncurrent liabilities	2,520,282	2,243,517
Commitments and contingencies (note 6)		
Stockholders' equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued: 66,994,516 shares in 2013 and 66,245,816 shares in 2012; outstanding, net of treasury shares: 66,972,104 shares in 2013 and 66,195,235 shares in 2012	670	662
Additional paid-in capital	247,165	233,642
Treasury stock, at cost: 22,412 shares in 2013 and 50,581 shares in 2012	(823)	(1,221)
Retained earnings	1,347,674	1,190,397
Accumulated other comprehensive loss	(7,902)	(9,014)
Total stockholders' equity	1,586,784	1,414,466
Total Liabilities and Stockholders' Equity	$4,736,845	$4,199,529

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

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SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)
(in thousands, except per share amounts)

	For the Three Months Ended September 30, 2013	For the Three Months Ended September 30, 2012	For the Nine Months Ended September 30, 2013	For the Nine Months Ended September 30, 2012
Operating revenues:				
Oil, gas, and NGL production revenue	$601,787	$373,928	$1,605,882	$1,049,131
Realized hedge gain (loss)	(489)	501	(1,777)	2,338
Loss on divestiture activity	(6,216)	(8,532)	(510)	(31,246)
Other operating revenues	18,025	13,054	53,052	40,571
Total operating revenues	613,107	378,951	1,656,647	1,060,794
Operating expenses:				
Oil, gas, and NGL production expense	158,921	102,447	434,291	280,713
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	195,792	192,432	620,232	523,610
Exploration	16,280	25,417	52,335	66,031
Impairment of proved properties	5,935	—	61,706	38,523
Abandonment and impairment of unproved properties	3,818	447	8,459	11,296
General and administrative	33,920	32,171	101,574	91,443
Change in Net Profits Plan liability	940	798	(6,423)	(17,342)
Derivative (gain) loss	39,933	55,856	(14,685)	(40,040)
Other operating expenses	20,084	12,219	71,192	40,780
Total operating expenses	475,623	421,787	1,328,681	995,014
Income (loss) from operations	137,484	(42,836)	327,966	65,780
Non-operating income (expense):				
Interest income	28	126	64	201
Interest expense	(24,488)	(18,362)	(65,170)	(45,352)
Income (loss) before income taxes	113,024	(61,072)	262,860	20,629
Income tax (expense) benefit	(42,334)	22,736	(98,921)	(7,740)
Net income (loss)	$70,690	$(38,336)	$163,939	$12,889
Basic weighted-average common shares outstanding	66,943	65,745	66,486	64,815
Diluted weighted-average common shares outstanding	68,253	65,745	67,969	67,343
Basic net income (loss) per common share	$1.06	$(0.58)	$2.47	$0.20
Diluted net income (loss) per common share	$1.04	$(0.58)	$2.41	$0.19
Dividends per common share	$0.05	$0.05	$0.10	$0.10

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

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SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)
(in thousands)

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
Net income (loss)	$70,690	$(38,336)	$163,939	$12,889
Other comprehensive income (loss), net of tax:				
Reclassification to earnings [1]	308	(315)	1,115	(1,465)
Pension liability adjustment	—	1	(3)	1
Total other comprehensive income (loss), net of tax	308	(314)	1,112	(1,464)
Total comprehensive income (loss)	$70,998	$(38,650)	$165,051	$11,425

[1] Reclassification from accumulated other comprehensive income related to de-designated hedges. Refer to Note 10 - Derivative Financial Instruments for further information.

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

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

	For the Nine Months Ended September 30, 2013	2012
Cash flows from operating activities:		
Net income	$163,939	$12,889
Adjustments to reconcile net income to net cash provided by operating activities:		
Loss on divestiture activity	510	31,246
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	620,232	523,610
Exploratory dry hole expense	5,878	18,551
Impairment of proved properties	61,706	38,523
Abandonment and impairment of unproved properties	8,459	11,296
Stock-based compensation expense	25,495	21,731
Change in Net Profits Plan liability	(6,423)	(17,342)
Derivative gain	(14,685)	(40,040)
Derivative cash settlement gain	12,715	32,803
Amortization of debt discount and deferred financing costs	3,914	5,692
Deferred income taxes	98,619	7,305
Plugging and abandonment	(7,453)	(1,804)
Other	2,929	906
Changes in current assets and liabilities:		
Accounts receivable	(45,209)	(18,682)
Refundable income taxes	510	2,339
Prepaid expenses and other	(2,971)	(6,203)
Accounts payable and accrued expenses	72,704	30,766
Net cash provided by operating activities	1,000,869	653,586
Cash flows from investing activities:		
Net proceeds from sale of oil and gas properties	20,498	48,663
Capital expenditures	(1,121,355)	(1,126,755)
Acquisition of proved and unproved oil and gas properties	(62,007)	(5,604)
Other	(3,509)	—
Net cash used in investing activities	(1,166,373)	(1,083,696)
Cash flows from financing activities:		
Proceeds from credit facility	976,500	1,234,500
Repayment of credit facility	(1,288,500)	(1,006,500)
Deferred financing costs related to credit facility	(3,444)	—
Net proceeds from 5.0% Senior Notes Due 2024	490,274	—
Net proceeds from 6.50% Senior Notes Due 2023	—	392,223
Repayment of 3.50% Senior Convertible Notes	—	(287,500)
Proceeds from sale of common stock	4,450	3,421
Dividends paid	(3,314)	(3,208)
Net share settlement from issuance of stock awards	(16,203)	(21,605)
Other	(9)	(231)
Net cash provided by financing activities	159,754	311,100

Net change in cash and cash equivalents	(5,750)	(119,010)
Cash and cash equivalents at beginning of period	5,926	119,194
Cash and cash equivalents at end of period	$176	$184

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

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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,	
	2013	2012
	(in thousands)	
Cash paid for interest, net of capitalized interest	$(59,841)	$(41,413)
Net cash refunded for income taxes	$259	$1,583

Dividends of approximately $3.3 million were declared by the Company’s Board of Directors, but not paid, as of September 30, 2013. Dividends of approximately $3.3 million were declared by the Company’s Board of Directors, but not paid, as of September 30, 2012.

As of September 30, 2013, and 2012, $238.7 million and $213.6 million, respectively, of accrued capital expenditures were included in accounts payable and accrued expenses in the Company’s condensed consolidated balance sheets. These oil and gas property additions are reflected in cash used in investing activities in the periods during which the payables are settled.

During the third quarter of 2013, the Company closed an exchange of properties in our Rocky Mountain region with a fair value of $25.0 million. The insignificant amount of cash consideration paid at closing for purchase price adjustments is reflected in the acquisition of proved and unproved oil and gas properties line item in the condensed consolidated statements of cash flows above.

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

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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, development, and production of crude oil and condensate, natural gas, and natural gas liquids (also respectively referred to as "oil," "gas," and "NGLs" throughout this report) in onshore North America, with a current 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 ("GAAP") 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 GAAP for complete financial statements. However, except as disclosed herein, there has been no material change in the information disclosed in the notes to consolidated financial statements included in SM Energy's Annual Report on Form 10-K for the year ended December 31, 2012 (the "2012 Form 10-K"). In the opinion of management, all adjustments, consisting of normal recurring accruals 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 unaudited condensed consolidated financial statements, the Company evaluated events subsequent to the balance sheet date of September 30, 2013, through the filing date of this report. Certain prior period amounts have been reclassified to conform to the current period presentation.

Significant Accounting Policies

The significant accounting policies followed by the Company are set forth in Note 1 to the Company's consolidated financial statements in the 2012 Form 10-K, and are supplemented by the notes to the unaudited condensed consolidated financial statements in this report. These unaudited condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes included in the 2012 Form 10-K.

Recently Issued Accounting Standards

On January 1, 2013, the Company adopted new authoritative accounting guidance issued by the Financial Accounting Standards Board ("FASB"), which enhanced disclosures by requiring an entity to disclose information about netting arrangements, including rights of offset, to enable users of its financial statements to understand the effect of those arrangements on its financial position and provided clarification as to the specific instruments that should be considered in these disclosures. These pronouncements were issued to facilitate comparison between financial statements prepared on the basis of GAAP and International Financial Reporting Standards. These disclosures are effective for annual and interim reporting periods beginning on or after January 1, 2013, and are to be applied retrospectively for all comparative periods presented. The impact of retrospectively adopting these pronouncements did not have a material impact on the Company's consolidated financial statements, but did impact the Company's disclosures. See Note 10 - Derivative Financial Instruments for tabular presentation of the Company's gross and net derivative positions.

On March 31, 2013, the Company adopted the presentation requirements of new authoritative accounting guidance issued by the FASB in February 2013. The purpose of the guidance was to improve the reporting of reclassifications out of accumulated other comprehensive income (loss) ("AOCIL") by requiring entities to report the effect of significant reclassifications out of AOCIL into current year income within the respective line items in net income. The presentation of those amounts may be on the face of the financial statements or in the notes thereto. This amendment was effective prospectively for periods beginning after December 15, 2012.

In February 2013, the FASB issued new authoritative accounting guidance related to the recognition and measurement of obligations arising from joint and several liability arrangements. This authoritative accounting guidance is effective for interim and annual periods beginning after December 15, 2013. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company's financial statements and disclosures.

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In July 2013, the FASB issued new authoritative accounting guidance related to the reporting of unrecognized tax benefits when a net operating loss carryforward, similar tax loss, or tax credit carryforward exists. This authoritative accounting guidance is effective for interim and annual periods beginning after December 15, 2013. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company's financial statements and disclosures, but does not believe its financial statements will be significantly impacted.

There are no additional new significant accounting standards applicable to the Company that had been issued but not yet adopted by the Company as of September 30, 2013.

Note 3 – 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 identify and expense any excess of carrying value over fair value less estimated costs to sell. Subsequent changes to the estimated fair value less the costs to sell will impact the measurement of assets held for sale for which fair value less estimated costs to sell is determined to be less than the carrying value of the assets.

As of September 30, 2013, the accompanying condensed consolidated balance sheets ("accompanying balance sheets") present $400.4 million of assets held for sale, net of accumulated depletion, depreciation, and amortization expense. A corresponding asset retirement obligation liability of $25.3 million is separately presented. The assets held for sale include certain assets located in all four of the Company's regions, all of which are recorded at the lesser of their carrying values or their respective fair value less estimated costs to sell. Write-downs to fair value less estimated costs to sell of $8.7 million for the three months ended September 30, 2013, and $10.1 million for the nine months ended September 30, 2013, are reflected in the loss on divestiture activity line item in the accompanying condensed consolidated statements of operations ("accompanying statements of operations").

The Company entered into multiple agreements to divest certain assets located in its Mid-Continent and Rocky Mountain regions that were classified as held for sale at September 30, 2013. The closings of these transactions are subject to the satisfaction of certain closing conditions, including the resolution of any title and environmental defects exceeding specified levels. Sales prices less estimated costs to sell were in excess of the carrying values of these assets as of September 30, 2013.

The Company determined that these planned asset sales do not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

Note 4 - Income Taxes

Income tax expense for the three months and nine months ended September 30, 2013, and 2012, differs from the amounts that would be provided by applying the statutory United States federal income tax rate to income before income taxes as a result of the estimated effect of percentage depletion, the effect of state income taxes, valuation allowance adjustments, and other permanent differences. The quarterly rate can also be impacted by the proportional effects of forecasted net income as of each period end presented.

The provision for income taxes consists of the following:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in thousands)			

Current portion of income tax expense (benefit):				
Federal	$—	$—	$—	$—
State	(46)	174	302	435
Deferred portion of income tax expense (benefit)	42,380	(22,910)	98,619	7,305
Total income tax expense (benefit)	$42,334	$(22,736)	$98,921	$7,740
	37.5 %	37.2 %	37.6 %	37.5 %

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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 various state tax jurisdictions. Cumulative effects of state rate changes are reflected in the period legislation is enacted. Similarly, a tax benefit from a research and development ("R&D") study is generally recognized in the period claimed. The year-to-date 2013 effective rate is essentially flat compared 2012, but reflects changes in the mix of permanent differences.

The Company and its subsidiaries file federal income tax returns and various state income tax returns. With certain exceptions, the Company is no longer subject to United States federal or state income tax examinations by these tax authorities for years before 2007. Federal tax law allowing for the calculation of an R&D credit was enacted in 2013, but the Company has not yet commissioned a study to calculate the credit for the 2012 or 2013 tax years. The table above excludes the impact for any credit that would be allowed under the new law. The Internal Revenue Service ("IRS") initiated an audit in the first quarter of 2012 related to R&D tax credits claimed by the Company for the 2007 through 2010 tax years. On April 23, 2013, the IRS issued a Notice of Proposed Adjustment disallowing $4.6 million of R&D tax credits claimed for open tax years during the audit period. The Company maintains it is entitled to the claimed credits, has timely appealed the IRS's decision, and agreed to a one-year federal statute extension for the 2008 and 2009 tax years.

On September 13, 2013, the United States Department of the Treasury and IRS issued the final and re-proposed tangible property regulations effective for tax years beginning January 1, 2014. The Company determined that its tax practices already take into account the regulations' requirements or such requirements are not material to the Company's financial statements.

Note 5 - Long-term Debt

Revolving Credit Facility

The Company and its lenders entered into a Fifth Amended and Restated Credit Agreement on April 12, 2013, which replaced the Company's previous credit facility. The Company incurred approximately $3.4 million in additional deferred financing costs associated with the amendment and extension of this credit facility. The credit facility has a maximum loan amount of $2.5 billion, current aggregate lender commitments of $1.3 billion, and a maturity date of April 12, 2018. The initial borrowing base under the credit facility was $1.9 billion. On May 20, 2013, the Company's borrowing base under the credit facility was automatically reduced by 25 percent of the aggregate principal amount of the newly-issued 5.0% Senior Notes due 2024 (the "2024 Notes"), to $1.775 billion. The borrowing base is subject to regular semi-annual redeterminations. On September 6, 2013, the lending group redetermined the Company's borrowing base under the credit facility and increased it to $2.2 billion. The borrowing base redetermination process under the credit facility considers the value of the Company's oil and gas properties and other assets, as determined by the bank group. The next scheduled redetermination date is April 1, 2014. Borrowings under the facility are secured by substantially all of the Company's proved 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 covenants under the credit facility as of September 30, 2013, and through the filing date of this report. The amended credit facility includes the same borrowing base utilization grid included in the Company's Fourth Amended and Restated Credit Agreement. Please refer to the borrowing base utilization grid in Note 5 - Long-term Debt in the Company's 2012 Form 10-K.

The following table presents the outstanding balance, total amount of letters of credit, and available borrowing capacity under the Company's credit facility as of October 23, 2013, September 30, 2013, and December 31, 2012:

	As of October 23, 2013	As of September 30, 2013	As of December 31, 2012
	(in millions)		
Credit facility balance	$59.0	$28.0	$340.0
Letters of credit [1]	$0.8	$0.8	$0.8
Available borrowing capacity	$1,240.2	$1,271.2	$659.2

[1] Letters of credit reduce the available borrowing capacity under the credit facility on a dollar-for-dollar basis.

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5.0% Senior Notes Due 2024

On May 20, 2013, the Company issued $500.0 million in aggregate principal amount of 2024 Notes. The 2024 Notes were issued at par and mature on January 15, 2024. The Company received net proceeds of $490.3 million after deducting fees of $9.7 million, which are being amortized as deferred financing costs over the life of the 2024 Notes. The net proceeds were used to reduce the Company's outstanding credit facility balance.

Prior to July 15, 2016, the Company may redeem, on one or more occasions, up to 35 percent of the aggregate principal amount of the 2024 Notes with the net cash proceeds of certain equity offerings at a redemption price of 105.0% of the principal amount thereof, plus accrued and unpaid interest. The Company may also redeem the 2024 Notes, in whole or in part, at any time prior to July 15, 2018, at a redemption price equal to 100 percent of the principal amount of the 2024 Notes to be redeemed, plus a specified make-whole premium and accrued and unpaid interest to the applicable redemption date.

On or after July 15, 2018, the Company may also redeem all or, from time to time, a portion of the 2024 Notes at the redemption prices set forth below, during the twelve-month period beginning on July 15 of each applicable year, expressed as a percentage of the principal amount redeemed, plus accrued and unpaid interest:

2018	102.500	%
2019	101.667	%
2020	100.833	%
2021 and thereafter	100.000	%

The 2024 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 2024 Notes. The Company is subject to certain covenants under the indenture governing the 2024 Notes that limit the Company's ability to incur additional indebtedness, issue preferred stock, and make restricted payments, including dividends; provided, however, that the first $6.5 million of dividends paid each year are not restricted by these covenants. The Company was in compliance with all covenants under its 2024 Notes as of September 30, 2013, and through the filing date of this report.

Additionally, on May 20, 2013, the Company entered into a registration rights agreement that provides holders of the 2024 Notes certain registration rights 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 ("SEC") with respect to its offer to exchange the 2024 Notes for substantially identical notes that are registered under the Securities Act. Under certain circumstances, the Company has agreed to file a shelf registration statement relating to the resale of the 2024 Notes in lieu of a registered exchange offer. If the exchange offer is not completed on or before May 20, 2014, or if the shelf registration statement, if required, is not declared effective within the time periods specified in the registration rights agreement, the Company has agreed to pay additional interest with respect to the 2024 Notes in an amount not to exceed one percent of the principal amount of the 2024 Notes until the exchange offer is completed or the shelf registration statement is declared effective.

Note 6 - Commitments and Contingencies

Commitments

During the third quarter of 2013, the Company entered into various marketing agreements whereby the Company is subject to certain gathering, transportation, and processing through-put commitments for up to 10 years pursuant to each contract. The Company may be required to make periodic deficiency payments for any shortfalls in delivering the minimum applicable annual, semi-annual, or monthly volume commitments. In the event that no product is delivered in accordance with these agreements, the aggregate deficiency payments total approximately $265.8 million as of September 30, 2013.

During the third quarter of 2013, the Company entered into an office lease with an initial term of 12 years and minimum lease payments of $12.9 million over the term beginning on the commencement date, which is anticipated to be in the first quarter of 2014.

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Contingencies

The Company is subject to litigation and claims arising in the ordinary course of business. The Company accrues for such items when a liability is probable and the amount can be reasonably estimated. In the opinion of management, the results of such pending litigation and claims will not have a material effect on the results of operations, the financial position, or the cash flows of the Company.

On January 27, 2011, Chieftain Royalty Company (“Chieftain”) filed a Class Action Petition against the Company in the District Court of Beaver County, Oklahoma, claiming damages related to royalty valuation on all of the Company’s Oklahoma wells. These claims include breach of contract, breach of fiduciary duty, fraud, unjust enrichment, tortious breach of contract, conspiracy, and conversion, based generally on asserted improper deduction of post-production costs. The Company removed this lawsuit to the United States District Court for the Western District of Oklahoma on February 22, 2011. The Company has responded to the petition and denied the allegations. The district court did not rule on Chieftain’s motion to certify the putative class, and stayed all proceedings until the United States Court of Appeals for the Tenth Circuit issued its rulings on class certification in two similar royalty class action lawsuits. On July 9, 2013, the Tenth Circuit issued its opinions, reversing the trial courts’ grant of class certification and remanding the matters to the trial courts for those cases. The district court presiding over the Company's case subsequently lifted its stay, and the Company expects Chieftain to file a new motion for class certification in the first half of 2015.

This case involves complex legal issues and uncertainties; a potentially large class of plaintiffs, and a large number of related producing properties, lease agreements and wells; and an alleged class period commencing in 1988 and spanning the entire producing life of the wells. Because the proceedings are in the early stages, with substantive discovery yet to be conducted, the Company is unable to estimate what impact, if any, the action will have on its financial condition, results of operations or cash flows. The Company is still evaluating the claims, but believes that it has properly paid royalties under Oklahoma law and has and will continue to vigorously defend this case.

In an unrelated matter, as of and for the nine months ended September 30, 2013, other operating expenses and accounts payable and accrued expenses included $17.8 million related to ongoing discussions to clarify the royalty payment provisions of various leases on certain South Texas & Gulf Coast acreage, of which $3.6 million of this amount was recorded during the three months ended September 30, 2013.

Note 7 - Compensation Plans

Cash Bonus Plan

During the first nine months of 2013 and 2012, the Company paid $16.0 million and $24.0 million, respectively, for cash bonuses earned during the 2012 and 2011 performance years, respectively. The general and administrative (“G&A”) expense and exploration expense line items in the accompanying statements of operations include $5.8 million and $4.3 million of accrued cash bonus plan expense for the three-month periods ended September 30, 2013, and 2012, respectively, and $16.7 million and $13.6 million for the nine-month periods ended September 30, 2013, and 2012, respectively, related to the respective performance year.

Restricted Stock Units Under the Equity Incentive Compensation Plan

The Company grants restricted stock units (“RSUs”) as part of its equity compensation program. Each RSU represents a right to one share of the Company’s common stock to be delivered upon settlement of the award at the end of the specified vesting period. Expense associated with RSUs is recognized as G&A expense and exploration expense over the vesting period of the award.

Total expense recorded for RSUs for the three-month periods ended September 30, 2013, and 2012, was $3.7 million and $3.9 million, respectively, and $10.0 million and $6.5 million for the nine-month periods ended September 30, 2013, and 2012, respectively. As of September 30, 2013, there was $22.7 million of total unrecognized compensation expense related to unvested RSU awards, which is being amortized through 2016.

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A summary of the status and activity of non-vested RSUs for the nine-month period ended September 30, 2013, is presented in the following table:

	RSUs	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	496,244	$51.81
Granted	329,939	$60.01
Vested	(206,509)	$49.73
Forfeited	(29,487)	$54.02
Non-vested at end of quarter	590,187	$57.02

The fair value of the RSUs granted during the first nine months of 2013 was $19.8 million. These RSUs will vest 1/3rd on each of the next three anniversary dates of the grant. During the first nine months of 2013, the Company settled 206,509 RSUs that related to awards granted in previous years. The Company and the majority of grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and award agreements. As a result, the Company issued 138,807 net shares of common stock. The remaining 67,702 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon delivery of the shares underlying those RSUs.

Performance Stock Units Under the Equity Incentive Compensation Plan

The Company grants performance share units ("PSUs") as part of its equity compensation program. PSUs are structurally the same as the previously granted performance share awards. The number of shares of the Company's common stock issued to settle PSUs ranges from zero to two times the number of PSUs awarded and is determined based on the Company's performance over a three-year measurement period. The performance criteria for the PSUs are based on a combination of the Company's annualized total shareholder return ("TSR") for the measurement period and the relative measure of the Company's TSR compared with the annualized TSRs of a group of peer companies for the measurement period. Expense associated with PSUs is recognized as G&A expense and exploration expense over the vesting period of the award.

Total expense recorded for PSUs for the three-month periods ended September 30, 2013, and 2012, was $3.5 million and $5.1 million, respectively, and $13.2 million for both of the nine-month periods ended September 30, 2013, and 2012. As of September 30, 2013, there was $22.7 million of total unrecognized compensation expense related to unvested PSUs to be amortized through 2016.

A summary of the status and activity of non-vested PSUs for the nine-month period ended September 30, 2013, is presented in the following table:

	PSUs [(1)]	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	669,308	$63.91
Granted	274,831	$64.13
Vested	(343,307)	$59.99
Forfeited	(22,371)	$69.50
Non-vested at end of quarter	578,461	$66.13

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

The fair value of the PSUs granted during the first nine months of 2013 was $17.6 million. These PSUs will fully vest on the third anniversary of the date of the grant. During the first nine months of 2013, the Company settled PSUs that were granted in 2010, which earned a 1.725 times multiplier, by issuing a net 387,461 shares of the Company's common stock in accordance with the terms of the PSU awards. The Company and the majority of grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and award agreements. As a result, the Company withheld 200,050 shares to satisfy income and payroll tax withholding obligations that occurred upon delivery of the shares underlying those PSUs.

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Stock Option Grants Under the Equity Incentive Compensation Plan

A summary of activity associated with the Company's Stock Option Plan for the nine months ended September 30, 2013, is presented in the following table:

	Shares	Weighted-Average Exercise Price	Aggregate Intrinsic Value (in thousands)
Outstanding, at beginning of year	267,846	$14.95	$9,983
Exercised	(177,995)	$13.89	$8,753
Forfeited	—		
Outstanding, at end of quarter	89,851	$17.01	$5,407
Vested and exercisable, at end of quarter	89,851	$17.01	$5,407

As of September 30, 2013, there was no unrecognized compensation expense related to stock option awards.

Director Shares

During the nine months ended September 30, 2013, and 2012, the Company issued 28,169 and 30,486 shares, respectively, of its common stock from treasury to its non-employee directors, under the Company's Equity Incentive Compensation Plan. The Company recorded no compensation expense related to these awards for the three months ended September 30, 2013, and $147,000 of compensation expense related to these awards for the three months ended September 30, 2012. The Company recorded $1.4 million and $1.3 million of compensation expense related to these awards for the nine months ended September 30, 2013, and 2012, respectively. All shares of common stock issued to the Company's non-employee directors are earned over the one-year service period following the date of grant.

Employee Stock Purchase Plan

Under the Company's Employee Stock Purchase Plan ("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 value from 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, and shares issued under the ESPP have no restriction period. The ESPP is intended to qualify under Section 423 of the Internal Revenue Code. The Company had 1.3 million shares available for issuance under the ESPP as of September 30, 2013. The Company issued 44,437 and 37,124 shares under the ESPP during the first nine months of 2013 and 2012, respectively. The fair value of ESPP grants is measured at the date of grant using the Black-Scholes option-pricing model.

Net Profits Interest Bonus Plan

Cash payments made or accrued under the Company's Net Profits Interest Bonus Plan ("Net Profits Plan") that have been recorded as either G&A expense or exploration expense are presented in the table below:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in thousands)			
General and administrative expense	$4,302	$4,083	$11,531	$12,177
Exploration expense	329	403	1,026	1,421
Total	$4,631	$4,486	$12,557	$13,598

Additionally, the Company accrued or made cash payments under the Net Profits Plan of $274,000 for the three-month period ended September 30, 2012, and $2.6 million and $2.0 million for the nine-month periods ended September 30, 2013, and 2012, respectively, as a result of divestiture proceeds. There were insignificant cash payments made or accrued relating to divestiture proceeds for the three-month period ended September 30, 2013. These cash payments are accounted for in the loss on divestiture activity line item in the accompanying statements of operations.

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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 G&A 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 G&A 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 paid to employees that have terminated employment and do not provide ongoing exploration support to the Company.

Note 8 - Pension Benefits

Pension Plans

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

Components of Net Periodic Benefit Cost for the Pension Plans

The following table presents the components of the net periodic benefit cost for the Pension Plans:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in thousands)			
Service cost	$1,572	$1,232	$4,718	$3,697
Interest cost	407	345	1,220	1,034
Expected return on plan assets that reduces periodic pension costs	(384)	(286)	(1,153)	(858)
Amortization of prior service costs	4	4	13	13
Amortization of net actuarial loss	306	197	917	591
Net periodic benefit cost	$1,905	$1,492	$5,715	$4,477

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 10 percent of the greater of the benefit obligation and the market-related value of assets are amortized over the average remaining service period of active participants.

Contributions

During the nine months ended September 30, 2013, the Company made a $4.3 million payment, which satisfied its $373,000 contribution requirement for the 2013 plan year, as well as funded a portion of its expected contribution requirement for the 2014 plan year.

Note 9 - Earnings per Share

Basic net income per common share 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 is calculated by dividing adjusted net income by the diluted weighted-average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist of in-the-money outstanding stock options, unvested RSUs, and contingent PSUs. The treasury stock method is used to measure the dilutive impact of unvested RSUs, contingent PSUs, and in-the-money stock options.

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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, that would be issuable at the end of the respective reporting period, assuming that date was the end of the contingency period applicable to such PSUs. For additional discussion on PSUs, please refer to Note 7 - Compensation Plans under the heading Performance Stock Units Under the Equity Incentive Compensation Plan.

Although all of the Company's 3.50% Senior Convertible Notes due 2027 ("3.50% Senior Convertible Notes") were redeemed or settled prior to September 30, 2012, potentially dilutive securities for this calculation included shares into which the 3.50% Senior Convertible Notes were convertible for the portion of the nine months ended September 30, 2012, for which they were outstanding. The Company's 3.50% Senior Convertible Notes had 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, in the event that holders of the notes elected 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. The potentially dilutive shares associated with this conversion feature were accounted for using the treasury stock method when shares of the Company's common stock traded at an average closing price that exceeded the $54.42 conversion price. Shares of the Company's common stock traded at an average closing price exceeding the conversion price, and were included on an adjusted weighted basis for the portion of the nine-month period ended September 30, 2012, for which they were outstanding, making them dilutive for that period. The dilutive net income per share calculation for the nine-month period ended September 30, 2012, was adjusted on a weighted basis for the conversion of the 3.50% Senior Convertible Notes.

The following table sets forth the calculations of basic and diluted earnings per share:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in thousands, except per share amounts)			
Net income (loss)	$70,690	$(38,336)	$163,939	$12,889
Basic weighted-average common shares outstanding	66,943	65,745	66,486	64,815
Add: dilutive effect of stock options, unvested RSUs, and contingent PSUs	1,310	—	1,483	1,870
Add: dilutive effect of 3.50% Senior Convertible Notes	—	—	—	658
Diluted weighted-average common shares outstanding	68,253	65,745	67,969	67,343
Basic net income (loss) per common share	$1.06	$(0.58)	$2.47	$0.20
Diluted net income (loss) per common share	$1.04	$(0.58)	$2.41	$0.19

Note 10 - Derivative Financial Instruments

Summary of Oil, Gas, and NGL Derivative Contracts in Place

The Company has entered into various commodity derivative contracts to mitigate a portion of its exposure to potentially adverse market changes in commodity prices and the associated impact on cash flows. All contracts are entered into for other-than-trading purposes. The Company's derivative contracts include swap and costless collar arrangements for oil, gas, and NGLs.

As of September 30, 2013, and through the filing date of this report, the Company has commodity derivative contracts outstanding through the second quarter of 2018 for a total of 19.8 million Bbls of oil production, 224.4 million

MMBtu of gas production, and 0.9 million Bbls of NGL production.

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

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The following tables summarize the approximate volumes and average contract prices of contracts the Company had in place as of September 30, 2013, and through the filing date of this report:

Oil Contracts

Oil Swaps

Contract Period	Volumes	Weighted-Average Contract Price
	(Bbls)	(per Bbl)
Remainder of 2013	1,118,000	$97.09
2014	5,164,000	$95.25
2015	2,911,000	$89.06
2016	2,704,000	$85.19
All oil swaps*	11,897,000	

*Oil swaps are comprised of NYMEX WTI (93%) and Argus Louisiana Light Sweet (“LLS”) (7%).

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(Bbls)	(per Bbl)	(per Bbl)
Remainder of 2013	1,480,000	$88.14	$114.12
2014	3,022,000	$84.07	$105.46
2015	3,366,000	$85.00	$94.25
All oil collars	7,868,000		

Gas Contracts

Gas Swaps

Contract Period	Volumes	Weighted-Average Contract Price
	(MMBtu)	(per MMBtu)
Remainder of 2013	19,047,000	$4.06
2014	64,453,000	$4.06
2015	49,328,000	$4.04
2016	36,126,000	$4.18
2017	23,430,000	$4.21
2018	10,200,000	$4.31
All gas swaps*	202,584,000	

*Gas swaps are comprised of IF El Paso Permian (3%), IF HSC (72%), IF NGPL TXOK (3%), IF NNG Ventura (2%), IF PEPL (8%), IF Reliant N/S (10%), and IF NGPL MidCont (2%).

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Gas Collars

Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(MMBtu)	(per MMBtu)	(per MMBtu)
Remainder of 2013	1,640,000	$4.39	$5.31
2014	5,734,000	$4.38	$5.36
2015	14,480,000	$3.96	$4.30
All gas collars*	21,854,000		

*Gas collars are comprised of IF El Paso Permian (2%), IF HSC (54%), IF NGPL TXOK (4%), IF NNG Ventura (5%), IF PEPL (7%), IF Reliant N/S (15%), and IF TETCO STX (13%).

NGL Contracts

NGL Swaps

Contract Period	Volumes	Weighted-Average Contract Price
	(Bbls)	(per Bbl)
Remainder of 2013	511,000	$53.16
2014	404,000	$58.42
All NGL swaps*	915,000	

*NGL swaps are comprised of OPIS Mont Belvieu Purity Ethane (7%), OPIS Mont Belvieu LDH Propane (45%), OPIS Mont Belvieu NON-LDH Isobutane (13%), OPIS Mont Belvieu NON-LDH Normal Butane (16%), and OPIS Mont Belvieu NON-LDH Natural Gasoline (19%).

Derivative Assets and Liabilities Fair Value

The Company’s commodity derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities. The fair value of the commodity derivative contracts was a net asset of $42.4 million and $38.7 million at September 30, 2013, and December 31, 2012, respectively.

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

	As of September 30, 2013			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity contracts	Current assets	$43,305	Current liabilities	$22,648
Commodity contracts	Noncurrent assets	28,659	Noncurrent liabilities	6,873
Derivatives not designated as hedging instruments		$71,964		$29,521

	As of December 31, 2012			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet	Fair Value	Balance Sheet	Fair Value

	Classification		Classification	
	(in thousands)			
Commodity contracts	Current assets	$37,873	Current liabilities	$8,999
Commodity contracts	Noncurrent assets	16,466	Noncurrent liabilities	6,645
Derivatives not designated as hedging instruments		$54,339		$15,644

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Offsetting of Derivative Assets and Liabilities

As of September 30, 2013, and December 31, 2012, all derivative instruments held by the Company were subject to enforceable master netting arrangements held by various financial institutions. In general, the terms of the Company's agreements provide for offsetting of amounts payable or receivable between it and the counterparty, at the election of both parties, for transactions that occur on the same date and in the same currency. The Company's agreements also provide that in the event of an early termination, the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. The Company's accounting policy is to not offset these positions in its accompanying balance sheets.

The following table provides a reconciliation between the gross assets and liabilities reflected on the accompanying balance sheets and the potential effects of master netting arrangements on the fair value of the Company's derivative contracts:

Offsetting of Derivative Assets and Liabilities	Derivative Assets As of September 30, 2013	December 31, 2012	Derivative Liabilities As of September 30, 2013	December 31, 2012
	(in thousands)			
Gross amounts presented in the accompanying balance sheets	$71,964	$54,339	$(29,521)	$(15,644)
Amounts not offset in the accompanying balance sheets	(29,225)	(13,400)	29,225	13,400
Net amounts	$42,739	$40,939	$(296)	$(2,244)

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 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. The Company had no derivatives designated as cash flow hedges for the three-month and nine-month periods ended September 30, 2013, and 2012.

As a result of discontinuing hedge accounting on January 1, 2011, fair values at December 31, 2010, were frozen in AOCIL as of the de-designation date and were reclassified into earnings as the original derivative transactions settled. As of September 30, 2013, all commodity derivative contracts that had been previously designated as cash flow hedges have settled and have been reclassified into earnings from AOCIL. Please refer to Note 11 - Fair Value Measurements for more information regarding the Company's derivative instruments, including its valuation techniques.

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The following table summarizes the components of the derivative (gain) loss presented in the accompanying statements of operations:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in thousands)			
Derivative cash settlement (gain) loss:				
Oil contracts	$13,538	$2,472	$13,786	$13,142
Gas contracts	(11,019)	(9,031)	(18,752)	(40,495)
NGL contracts	(1,231)	(4,362)	(7,749)	(5,450)
Total derivative cash settlement (gain) loss [1]	$1,288	$(10,921)	$(12,715)	$(32,803)
Derivative (gain) loss:				
Oil contracts	30,488	30,667	8,233	(32,616)
Gas contracts	(2,264)	28,231	(12,462)	40,464
NGL contracts	10,421	7,879	2,259	(15,085)
Total derivative (gain) loss [2]	$39,933	$55,856	$(14,685)	$(40,040)

(1) Derivative cash settlement (gain) loss is reported in the derivative cash settlement gain line item on the condensed consolidated statements of cash flows within net cash provided by operating activities.

(2) Total derivative (gain) loss is reported in the derivative gain line item on the condensed consolidated statements of cash flows within net cash provided by operating activities.

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

	Derivatives	Location in Statements of Operations	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
			2013	2012	2013	2012
			(in thousands)			
Amount reclassified from AOCIL	Commodity contracts	Realized hedge gain (loss)	$308	$(315)	$1,115	$(1,465)

The Company realized a net hedge loss of $489,000 and a net hedge gain of $501,000 from its commodity derivative contracts for the three months ended September 30, 2013, and 2012, respectively, and a net hedge loss of $1.8 million and a net hedge gain of $2.3 million for the nine months ended September 30, 2013, and 2012, respectively, shown net of income tax in the table above. Realized hedge gains and losses are comprised of settlements on commodity derivative contracts that were previously designated as cash flow hedges and are reported in total operating revenues in the accompanying statements of operations.

Credit Related Contingent Features

As of September 30, 2013, and through the filing date of this report, all of the Company’s derivative counterparties were members of the Company’s credit facility syndicate. The Company’s obligations under its credit facility and derivative contracts are secured by liens on substantially all of the Company’s proved oil and gas properties.

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Note 11 - Fair Value Measurements

The Company follows fair value measurement authoritative accounting guidance for all assets and liabilities measured at fair value. That authoritative accounting 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 fair value 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 or 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 assets and liabilities that are measured at fair value and their classification within the fair value hierarchy as of September 30, 2013:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives [1]	$—	$71,964	$—
Proved oil and gas properties [2]	$—	$—	$11,443
Unproved oil and gas properties [2]	$—	$—	$20,915
Oil and gas properties held for sale [2]	$—	$—	$15,349
Liabilities:			
Derivatives [1]	$—	$29,521	$—
Net Profits Plan [1]	$—	$—	$72,404
Asset retirement obligation [2]	$—	$—	$1,573

[1] This represents a financial asset or liability that is measured at fair value on a recurring basis.
[2] This represents a non-financial asset or liability that is measured at fair value on a nonrecurring basis.

The following is a listing of the Company's assets and liabilities that are measured at fair value and their classification within the fair value hierarchy as of December 31, 2012:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives [1]	$—	$54,339	$—
Proved oil and gas properties [2]	$—	$—	$209,959
Unproved oil and gas properties [2]	$—	$—	$42,765
Oil and gas properties held for sale [2]	$—	$—	$16,527
Liabilities:			
Derivatives [1]	$—	$15,644	$—
Net Profits Plan [1]	$—	$—	$78,827

[1] This represents a financial asset or liability that is measured at fair value on a recurring basis.
[2] This represents a non-financial asset or liability that is measured at fair value on a nonrecurring basis.

Both financial and non-financial assets and liabilities are categorized within the above fair value 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 above fair value hierarchy.

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Derivatives

The Company uses Level 2 inputs to measure the fair value of oil, 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. These 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, gas, and NGL commodity derivative markets are highly active.

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 require counterparties to post collateral if their ratings deteriorate. In some instances the Company will attempt to novate the trade to a more stable counterparty.

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

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

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, gas, and NGL 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 lower commodity prices result in a smaller Net Profits Plan liability.

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 Company's 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, discount rates, and overall market conditions. The Company regularly assesses the current market environment. 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 oil, gas, and NGL commodity markets.

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If the commodity prices used in the calculation changed by five percent, the liability recorded at September 30, 2013, would differ by approximately $6 million. A one percent increase or decrease in the discount rate would result in a change of approximately $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 its Net Profits Plan liability. As such, the recorded fair value is based entirely on management estimates that are described within this footnote. While some inputs to the Company's calculation of fair value on the Net Profits Plan's future payments are from published sources, others, such as the discount rate and the expected future cash flows, are derived from the Company's own calculations and estimates.

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

	For the Nine Months Ended September 30, 2013 (in thousands)	
Beginning balance	$78,827	
Net increase in liability [1]	8,736	
Net settlements [1] [2]	(15,159	)
Transfers in (out) of Level 3	—	
Ending balance	$72,404	

(1) Net changes in the Company's Net Profits Plan liability are shown in the Change in Net Profits Plan liability line item of the accompanying statements of operations.

(2) Settlements represent cash payments made or accrued under the Net Profits Plan. The Company accrued or made cash payments under the Net Profits Plan of $2.6 million relating to divestiture proceeds for the nine months ended September 30, 2013.

Long-term Debt

The following table reflects the fair value of the 6.625% Senior Notes due 2019 (the "2019 Notes"), the 6.50% Senior Notes due 2021 (the "2021 Notes"), the 6.50% Senior Notes due 2023 (the "2023 Notes"), and the 2024 Notes (collectively referred to as the "Senior Notes") measured using Level 1 inputs based on quoted secondary market trading prices. The Senior Notes were not presented at fair value on the accompanying balance sheets as of September 30, 2013, or December 31, 2012, as they are recorded at historical value.

	As of September 30, 2013	As of December 31, 2012
	(in thousands)	
2019 Notes	$368,375	$371,875
2021 Notes	$374,500	$371,070
2023 Notes	$408,000	$424,200
2024 Notes [1]	$461,565	N/A

(1) The 2024 Notes were issued on May 20, 2013.

The carrying value of the Company's credit facility approximates its fair value, as the applicable interest rates are floating, based on prevailing market rates.

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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 may not be recoverable. 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 based on the best information available and was estimated to be 12 percent as of September 30, 2013, and December 31, 2012. The Company believes that the discount rate is representative of current market conditions and takes into account estimates of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. The prices for oil and gas are forecasted based on New York Mercantile Exchange (“NYMEX”) strip pricing, adjusted for basis differentials, for the first five years, after which a flat terminal price is used for each commodity stream. The prices for NGLs are forecasted using Oil Price Information System (“OPIS”) Mont Belvieu pricing, adjusted for basis differentials, for as long as the market is actively trading, after which a flat terminal price is used. Future operating costs are also adjusted as deemed appropriate for these estimates. Proved properties classified as held for sale are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties. If an estimated selling price is not available, the Company utilizes the income valuation technique discussed above.

See Unproved Oil and Gas Properties below for discussion of the fair value measurement of acquired oil and gas properties.

Unproved Oil and Gas Properties

Unproved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. To measure the fair value of unproved properties, the Company uses a market approach, which takes into account the following significant assumptions: future development plans, risk weighted potential resource recovery, and estimated reserve values. Unproved properties classified as held for sale are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties. If an estimated selling price is not available, the Company utilizes a market approach, which estimates acreage value based on the price received for similar acreage in recent transactions by the Company or other market participants in the principal market.
Acquisitions of proved and unproved properties are measured at fair value as of the acquisition date using a discounted cash flow model similar to the Company’s approach in measuring the fair value of proved and unproved properties, as discussed in the paragraphs above. Due to the unobservable characteristics of the inputs, the fair value of acquired properties are considered Level 3 within the fair value hierarchy.

Asset Retirement Obligations

The Company utilizes the income valuation technique to determine the fair value of the asset retirement obligation liability at the point of inception by applying a credit-adjusted risk-free rate, which takes into account the Company’s credit risk, the time value of money, and the current economic state, to the undiscounted expected abandonment cash flows. Given the unobservable nature of the inputs, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. There were asset retirement obligations of $1.6 million recorded at fair value in the accompanying balance sheets at September 30, 2013. There were no asset retirement obligations recorded at fair value in the accompanying balance sheets at December 31, 2012.

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

This discussion and analysis contains forward-looking statements. Refer to Cautionary Information about Forward-Looking Statements at the end of this item for an explanation of these types of statements.

Overview of the Company, Highlights, and Outlook

General Overview

We are an independent energy company engaged in the acquisition, exploration, development, and production of oil, gas, and NGLs in onshore North America. Our assets include leading positions in the Eagle Ford shale and Bakken/Three Forks resource plays, oil-focused plays in the Permian Basin, and positions in emerging plays in East Texas and the Powder River Basin in Wyoming. We have built a portfolio of onshore properties in the contiguous United States primarily through early entry 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 provides for stable and predictable production and reserves growth. Furthermore, by entering these plays early, we believe we can capture larger resource potential at a lower cost. At year-end 2012, liquids constituted the majority of our reserves compared to a majority of natural gas in prior periods. As a result, we are now reporting volumes on a barrels of oil equivalent ("BOE") basis rather than on a thousand cubic feet equivalent ("MCFE") basis. Prior year volumes have been conformed to the current year presentation.

Our principal business strategy is to focus on the early capture of resource plays in order to create and then enhance value for our stockholders while maintaining a strong balance sheet. We strive to leverage industry-leading exploration and leasehold acquisition teams to quickly acquire and test new resource play concepts at a reasonable cost. Once we have identified potential value through these efforts, our goal is to develop such potential through top-tier operational and project execution and to mitigate our risks by selectively divesting of certain assets when we deem appropriate. We continually examine our portfolio for opportunities to improve the quality of our asset base in order to optimize our returns and preserve our financial strength.

In the third quarter of 2013, we had the following financial and operational results:

- Average net daily production for the three months ended September 30, 2013, was 41.6 MBbls of oil, 418.1 MMcf of gas, and 27.5 MBbls of NGLs, for a quarterly record equivalent daily production rate of 138.8 MBOE, compared with 103.3 MBOE for the same period in 2012. Please see additional discussion below under the caption Production Results.

- Net income for the three months ended September 30, 2013, was $70.7 million, or $1.04 per diluted share, compared to net loss for the three months ended September 30, 2012, of $38.3 million, or $0.58 loss per diluted share. Please refer to the Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2013, and 2012 for additional discussion regarding the components of net income (loss).

- Costs incurred for oil and gas property acquisitions and exploration and development activities for the three months ended September 30, 2013, were $438.1 million, compared with $443.1 million for the same period in 2012. The majority of costs incurred during this period were in our Eagle Ford shale, Bakken/Three Forks, and Permian programs. Please refer to the caption Uses of Cash in the Overview of Liquidity and Capital Resources section below for additional discussion on how we expect to fund our capital program.

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EBITDAX, a non-GAAP financial measure, for the three months ended September 30, 2013, was $410.4 million, which was in excess of our capital expenditures for the three months ended September 30, 2013. EBITDAX for the three months ended September 30, 2012, was $260.9 million. Please refer to the caption Non-GAAP Financial Measures below for additional discussion, including our definition of EBITDAX and reconciliations of our GAAP net income and net cash provided by operating activities to EBITDAX.

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Oil, Gas, and NGL Prices

Our financial condition and the results of our operations are significantly affected by the prices we receive for our oil, gas, and NGL production, which can fluctuate dramatically. We sell the majority of our gas under contracts using first-of-the-month index pricing, which means 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 paying us a monthly average of the posted OPIS daily settlement prices, adjusted for processing, transportation, and location differentials. Our oil and condensate are sold using contracts paying us various industry posted prices, most commonly NYMEX West Texas Intermediate ("WTI") or Argus LLS. We are paid the average of the daily settlement price for the respective posted prices for the period in which the product is produced, adjusted for quality, transportation, API gravity, and location differentials. Substantially all of our oil production in our South Texas & Gulf Coast region is condensate. When we refer to realized oil, gas, and NGL prices below, the disclosed price represents the average price for the respective period unless otherwise indicated.

The following table summarizes commodity price data for the second and third quarters of 2013, as well as the third quarter of 2012:

	For the Three Months Ended		
	September 30, 2013	June 30, 2013	September 30, 2012
Crude Oil (per Bbl):			
Average NYMEX price	$105.82	$94.14	$92.16
Realized price	$96.44	$90.00	$83.98
Natural Gas:			
Average NYMEX price (per MMBtu)	$3.55	$4.02	$2.88
Realized price (per Mcf)	$3.81	$4.28	$3.05
Natural Gas Liquids (per Bbl):			
Average OPIS price	$40.23	$37.76	$40.19
Realized price	$34.01	$34.09	$34.82

Note: Average OPIS prices per barrel of NGL are based on a product mix of 37% Ethane, 32% Propane, 6% Isobutane, 11% Normal Butane, and 14% Natural Gasoline for all periods presented. This product mix represents the industry standard composite barrel and does not necessarily represent our product mix for NGL production. Our actual product mix is reflected in actual prices received for NGLs produced.

We expect future prices for oil, gas, and NGLs to be volatile. In addition to supply and demand fundamentals, as a global commodity, the price of oil will continue to be impacted by real or perceived geopolitical risks in oil producing regions of the world, particularly the Middle East. The relative strength of the U.S. dollar compared to other currencies could affect the price of oil. The supply of NGLs in the U.S. is expected to grow in the near term as a result of the number of industry participants targeting projects that produce these products. The pace of NGL production is growing faster than the capacity to process or consume NGLs, which will likely negatively impact pricing in the near term. The prices of several NGL products correlate to the price of oil and accordingly are likely to directionally follow that market. Gas prices have been under sustained downward pressure due to high levels of supply and continued growth in production levels. The following table below summarizes 12-month strip prices for NYMEX WTI oil, NYMEX Henry Hub gas, and OPIS NGLs (same product mix as discussed under the table above) as of September 30, 2013, and October 23, 2013:

	As of October 23, 2013	As of September 30, 2013

NYMEX WTI oil (per Bbl)	$ 94.72	$ 97.91
NYMEX Henry Hub gas (per MMBtu)	$ 3.80	$ 3.80
OPIS NGLs (per Bbl)	$ 40.44	$ 39.30

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

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Derivative Activity

We use financial derivative instruments as part of our financial risk management program. We have a financial risk management policy governing our use of derivatives. The amount 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 our current derivative contracts, we believe we have established a base cash flow stream for our future operations and have partially reduced our exposure to volatility in commodity prices. Our use of costless collars for a portion of our derivatives allows us to participate in some of the upward movements in oil, gas, and NGL prices while also setting a price floor for a portion of our production. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information regarding our oil, gas, and NGL derivatives.

The following table presents our realized prices and the effects of derivative cash settlements for the second and third quarters of 2013, as well as the third quarter of 2012:

	For the Three Months Ended		
	September 30, 2013	June 30, 2013	September 30, 2012
Crude Oil (per Bbl):			
Realized price	$96.44	$90.00	$83.98
Effects of derivative cash settlements	$(3.66)	$(0.36)	$(1.83)
Natural Gas (per Mcf):			
Realized price	$3.81	$4.28	$3.05
Effects of derivative cash settlements	$0.29	$(0.05)	$0.39
Natural Gas Liquids (per Bbl):			
Realized price	$34.01	$34.09	$34.82
Effects of derivative cash settlements	$0.49	$1.91	$2.57

The Dodd-Frank Wall Street Reform and Consumer Protection Act (“Dodd-Frank Act”) included provisions requiring over-the-counter derivative transactions to be cleared through clearinghouses and traded on exchanges. On July 10, 2012, the Commodity Futures Trading Commission (“CFTC”) and the SEC adopted final joint rules under Title VII of the Dodd-Frank Act, which define certain terms that determine what types of transactions will be subject to regulation under the Dodd-Frank Act swap rules. The issuance of these final rules also triggers compliance dates for a number of other final Dodd-Frank Act rules, including new rules proposed by the CFTC governing margin requirements for uncleared swaps entered into by non-bank swap entities, and new rules proposed by U.S. banking regulators regarding margin requirements for uncleared swaps entered into by bank swap entities. The ultimate effect on our business of these new rules and any additional regulations is currently uncertain. Under CFTC rules we believe our derivative activity will qualify for the non-financial, commercial end-user exception, which exempts derivatives intended to hedge or mitigate commercial risk entered into by entities predominantly engaged in non-financial activity from the mandatory swap clearing requirement. However, we are not certain whether the provisions of the final rules and regulations will exempt us 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.

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Third Quarter 2013 Highlights and Outlook for the Remainder of 2013

Operational Activities. We expect our 2013 capital budget to be $1.65 billion, with $1.24 billion deployed to our development programs. Within our development capital budget, over 90% of the capital is allocated to our Eagle Ford, Bakken/Three Forks and Permian programs.
In our operated Eagle Ford shale program in south Texas, we made 25 flowing completions during the third quarter of 2013. Our program for the remainder of the year will continue to focus largely on multi-well pad drilling on the northern portions of our acreage position, which have higher condensate and NGL yields. We believe we have secured the requisite services, such as gas pipeline takeaway capacity and drilling and completion services, to support our current development plans. At the end of the third quarter, the third party build-out of our operated Eagle Ford gathering system was on schedule with 12 facilities in service. In our non-operated Eagle Ford program, the operator had nine drilling rigs running during the third quarter of 2013. We expect the majority of our non-operated Eagle Ford drilling and completion program to be funded by Mitsui E&P Texas, LP ("Mitsui") throughout 2013 and into 2014 under the terms of our Acquisition and Development Agreement with Mitsui. Costs that are not associated with drilling or completion activities, such as infrastructure construction, are not carried by Mitsui, and we are responsible for our proportionate share of those costs.
During the third quarter of 2013, we made 13 gross operated flowing completions in our Bakken/Three Forks program in the North Dakota portion of the Williston Basin focusing on our Gooseneck, Raven, and Bear Den areas. During the third quarter, we ran three rigs and expect to maintain this level of activity for the rest of the year. We have begun our infill drilling program using multi-well pads, which we believe will further optimize this program.
As of the filing date of this report, we have leased or committed to acquire approximately 129,750 net acres in the Permian Basin comprised of approximately 72,500 net acres in the Midland Basin which we believe is prospective for the Wolfcamp shale, approximately 54,500 net acres in our Tredway Mississippian program, and approximately 2,750 net acres in southeast New Mexico. In our Permian program, we are currently focused on three areas: the development of the Bone Spring formation in southeast New Mexico, the delineation of the Mississippian limestone formation, and the testing of various shale targets including the Wolfcamp shale in the Midland Basin. We operated three drilling rigs during the third quarter of 2013.

We have an ongoing exploration program to acquire leasehold and test concepts in new plays. In 2013, we have primarily focused on two emerging new venture plays, the Powder River Basin in Wyoming and various targets in East Texas. In the Powder River Basin, we have approximately 140,000 net acres, of which approximately 100,000 of those acres are prospective for the Frontier formation. We currently have one rig operating in the basin that is testing and delineating our position. Our other new venture program of note is in East Texas, where we have leased or committed to acquire approximately 20,000 net acres to our position during the third quarter. We now have an approximately 215,000 net acre position in the play and we continue to pursue other leasing opportunities in this region. We currently have two rigs running in the play, and we expect to conduct tests of intervals of interest, including the Eagle Ford shale and Woodbine formation, during the remainder of the year.

Please refer to Overview of Liquidity and Capital Resources for additional discussion regarding how we intend to fund our 2013 capital program.
Production Results. The table below provides a regional breakdown of our production for the third quarter of 2013:

	South Texas & Gulf Coast	Mid-Continent	Permian	Rocky Mountain	Total [(1)]
Third quarter of 2013 production:					
Oil (MMBbl)	1.5	0.2	0.5	1.7	3.8
Gas (Bcf)	25.3	10.7	1.0	1.5	38.5
NGLs (MMBbl)	2.5	—	—	—	2.5
Equivalent (MMBOE)	8.2	2.0	0.6	2.0	12.8
Avg. daily equivalents (MBOE/d)	89.0	21.7	6.8	21.2	138.8

Relative percentage	64	%	16	%	5	%	15	%	100	%

(1) Totals may not add due to rounding.

We had record production in the third quarter of 2013, which was primarily driven by the continued development of our operated and non-operated Eagle Ford shale programs in our South Texas & Gulf Coast region. Please refer to Comparison of

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Financial Results and Trends Between the Three Months Ended September 30, 2013, and 2012 for additional discussion on production.

Equity Compensation. During the third quarter of 2013, we granted 329,939 RSUs and 274,831 PSUs pursuant to our long-term equity incentive program. Also during the third quarter of 2013, we issued 526,268 shares of our common stock to settle PSU and RSU awards granted in previous years. Please refer to Note 7 - Compensation Plans in Part I, Item 1 of this report for additional discussion.

Revolving Credit Facility. Our lenders increased our credit facility's borrowing base to $2.2 billion from $1.775 billion during the third quarter of 2013. Please refer to the caption Credit Facility in the Overview of Liquidity and Capital Resources section below and Note 5 - Long-term Debt in Part I, Item 1 of this report for additional discussion.

First Nine Months of 2013 Highlights

Production Results. The table below provides a regional breakdown of our first nine months of 2013 production:

	South Texas & Gulf Coast		Mid-Continent		Permian		Rocky Mountain		Total [1]	
First nine months of 2013 production:										
Oil (MMBbl)	3.8		0.4		1.3		4.7		10.2	
Gas (Bcf)	71.1		32.1		2.6		4.1		109.9	
NGLs (MMBbl)	6.4		0.1		—		—		6.6	
Equivalent (MMBOE)	22.1		5.9		1.7		5.4		35.1	
Avg. daily equivalents (MBOE/d)	80.8		21.7		6.3		19.8		128.6	
Relative percentage	63	%	17	%	5	%	15	%	100	%

(1) Totals may not add due to rounding.

Please refer to Third Quarter 2013 Highlights and Outlook for the Remainder of 2013 above and Comparison of Financial Results and Trends Between the Nine Months Ended September 30, 2013, and 2012 for additional discussion on production.

2024 Notes. On May 20, 2013, we issued $500.0 million in aggregate principal amount of 2024 Notes. The notes were issued at par and mature on January 15, 2024. We received net proceeds of $490.3 million from this issuance, which we used to reduce outstanding borrowings under our credit facility. Please refer to Note 5 - Long-term Debt in Part I, Item 1 of this report for additional information.

Revolving Credit Facility. During the first nine months of 2013, we and our lenders entered into a Fifth Amended and Restated Credit Agreement, which increased our aggregate lender commitments to $1.3 billion from $1.0 billion and extended the maturity date of our revolving credit facility to April 12, 2018. Please refer to the Third Quarter 2013 Highlights and Outlook for the Remainder of 2013 section above for discussion on the increase in our borrowing base in the third quarter and references to other sections throughout this report that discuss our revolving credit facility.

Costs Incurred in Oil and Gas Producing Activities. For the nine months ended September 30, 2013, we incurred $1.3 billion in costs related to oil and gas property acquisitions and exploration and development activities, including both capitalized and expensed amounts. The majority of costs incurred during this period were in our Eagle Ford shale, Bakken/Three Forks, and Permian programs. Please refer to the caption Uses of Cash in the Overview of Liquidity and Capital Resources section below for additional discussion on how we expect to fund our capital program.

Impairment of Proved Properties. During the first nine months of 2013, we recorded impairment of proved properties expense of $61.7 million. We recorded an impairment of $21.2 million in the first quarter of 2013 related to Olmos interval, dry gas assets in our South Texas & Gulf Coast region as a result of a plugging and abandonment program. In the second and third quarters of 2013, we recorded impairment expense of $34.6 million and $5.9 million, respectively, as a result of our decision to no longer pursue the development of certain underperforming assets.

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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, 2013, and the immediately preceding three quarters. Additional details of per BOE costs are presented later in this section.

	For the Three Months Ended			
	September 30, 2013	June 30, 2013	March 31, 2013	December 31, 2012
	(in millions, except for production data)			
Production (MMBOE)	12.8	12.0	10.3	10.1
Oil, gas, and NGL production revenue	$601.8	$534.5	$469.6	$424.7
Lease operating expense	$61.0	$56.2	$54.7	$48.0
Transportation costs	$68.8	$67.0	$47.4	$43.0
Production taxes	$29.1	$26.5	$23.5	$20.2
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$195.8	$225.7	$198.7	$204.3
Exploration	$16.3	$20.7	$15.4	$24.2
General and administrative	$33.9	$35.4	$32.3	$28.4
Net income (loss)	$70.7	$76.5	$16.7	$(67.1)

Selected Performance Metrics:

	For the Three Months Ended			
	September 30, 2013	June 30, 2013	March 31, 2013	December 31, 2012
Average net daily production equivalent (MBOE per day)	138.8	131.8	115.0	109.9
Lease operating expense (per BOE)	$4.77	$4.69	$5.28	$4.74
Transportation costs (per BOE)	$5.38	$5.59	$4.58	$4.25
Production taxes as a percent of oil, gas, and NGL production revenue	4.8%	5.0%	5.0%	4.8%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)	$15.33	$18.82	$19.20	$20.20
General and administrative (per BOE)	$2.66	$2.95	$3.12	$2.81

Note: Amounts may not recalculate due to rounding.

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

	For the Three Months Ended September 30,		Amount Change Between Periods	Percent Change Between Periods		For the Nine Months Ended September 30,		Amount Change Between Periods	Percent Change Between Periods	
	2013	2012				2013	2012			
Net production volumes [1]										
Oil (MMBbl)	3.8	2.6	1.2	46	%	10.2	7.5	2.7	36	%
Gas (Bcf)	38.5	31.3	7.2	23	%	109.9	88.1	21.8	25	%
NGLs (MMBbl)	2.5	1.7	0.9	53	%	6.6	4.2	2.4	57	%
Equivalent (MMBOE)	12.8	9.5	3.3	34	%	35.1	26.4	8.7	33	%
Average net daily production [1]										
Oil (MBbl per day)	41.6	28.6	13.0	46	%	37.3	27.4	10.0	36	%
Gas (MMcf per day)	418.1	340.3	77.7	23	%	402.4	321.5	80.8	25	%
NGLs (MBbl per day)	27.5	18.0	9.5	53	%	24.2	15.3	8.9	58	%
Equivalent (MBOE per day)	138.8	103.3	35.5	34	%	128.6	96.3	32.3	34	%
Oil, gas, & NGL production revenue (in millions)										
Oil production revenue	$368.9	$220.6	$ 148.3	67	%	$946.6	$642.7	$ 303.9	47	%
Gas production revenue	146.7	95.7	51.0	53	%	429.3	244.6	184.7	76	%
NGL production revenue	86.2	57.6	28.6	50	%	230.0	161.8	68.2	42	%
Total	$601.8	$373.9	$ 227.9	61	%	$1,605.9	$1,049.1	$ 556.8	53	%
Oil, gas, & NGL production expense (in millions)										
Lease operating expense	$61.0	$46.5	$ 14.5	31	%	$171.9	$132.1	$ 39.8	30	%
Transportation costs	68.8	37.0	31.8	86	%	183.2	95.9	87.3	91	%
Production taxes	29.1	18.9	10.2	54	%	79.2	52.7	26.5	50	%
Total	$158.9	$102.4	$ 56.5	55	%	$434.3	$280.7	$ 153.6	55	%
Realized price										
Oil (per Bbl)	$96.44	$83.98	$ 12.46	15	%	$92.93	$85.76	$ 7.17	8	%
Gas (per Mcf)	$3.81	$3.05	$ 0.76	25	%	$3.91	$2.78	$ 1.13	41	%
NGLs (per Bbl)	$34.01	$34.82	$ (0.81)	(2	)%	$34.77	$38.53	$ (3.76)	(10	)%
Per BOE	$47.13	$39.36	$ 7.77	20	%	$45.74	$39.77	$ 5.97	15	%
Per BOE Data [1]										
Production costs:										
Lease operating expenses	$4.77	$4.89	$ (0.12)	(2	)%	$4.89	$5.01	$ (0.12)	(2	)%
Transportation costs	$5.38	$3.90	$ 1.48	38	%	$5.22	$3.64	$ 1.58	43	%
Production taxes	$2.29	$1.99	$ 0.30	15	%	$2.26	$2.00	$ 0.26	13	%
General and administrative	$2.66	$3.39	$ (0.73)	(22	)%	$2.89	$3.47	$ (0.58)	(17	)%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$15.33	$20.25	$ (4.92)	(24	)%	$17.67	$19.85	$ (2.18)	(11	)%
Derivative cash settlement [2]	$(0.14)	$1.20	$ (1.34)	(112	)%	$0.31	$1.33	$ (1.02)	(77	)%
Earnings per share information										
Basic net income (loss) per common share	$1.06	$(0.58)	$ 1.64	283	%	$2.47	$0.20	$ 2.27	1,135	%
Diluted net income (loss) per common share	$1.04	$(0.58)	$ 1.62	279	%	$2.41	$0.19	$ 2.22	1,168	%
	66,943	65,745	1,198	2	%	66,486	64,815	1,671	3	%

Basic weighted-average common shares outstanding (in thousands)										
Diluted weighted-average common shares outstanding (in thousands)	68,253	65,745	2,508	4	%	67,969	67,343	626	1	%

(1) Amounts and percentage changes may not recalculate due to rounding.
(2) Derivative cash settlements are included within the realized hedge gain (loss) and derivative (gain) loss line items in the accompanying statements of operations.

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We present per BOE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis. Average daily net reported production increased 34 percent for both the three and nine-month periods ended September 30, 2013, when compared with the same periods in 2012, driven primarily by the development of our Eagle Ford shale assets.

Changes in production volumes, revenues, and costs reflect the cyclical and highly volatile nature of our industry. Our realized price on a per BOE basis for the three and nine months ended September 30, 2013, increased 20 percent and 15 percent, respectively, compared to the same periods in 2012, due to improved oil and gas prices.

Lease operating expenses ("LOE") on a per BOE basis decreased two percent for both the three and nine-month periods ended September 30, 2013, compared to the same periods in 2012. Overall, LOE costs increased; however, production increased at a faster rate, thereby reducing LOE on a per BOE basis. Generally, we expect LOE on a per BOE basis to decrease, as we anticipate production will continue to increase at a faster rate than our increase in absolute LOE expense.

Production taxes on a per BOE basis for the three and nine months ended September 30, 2013, increased 15 percent and 13 percent, respectively, compared to the same periods in 2012, as a result of the sizable State of Oklahoma incentive tax rebate recorded in the second quarter of 2012, which significantly decreased that quarter's per BOE rate. Additionally, we are receiving smaller incentive tax rebates on newer wells drilled in our South Texas & Gulf Coast region in 2013. We generally expect production tax expense to trend with oil, gas, and NGL revenues.

Transportation costs on a per BOE basis for the three and nine months ended September 30, 2013, increased 38 percent and 43 percent, respectively, compared to the same periods in 2012. Our Eagle Ford program has meaningfully higher transportation expense per unit of production compared to our other regions. Ongoing development of the Eagle Ford shale program has resulted in these assets becoming a larger portion of our total production, thereby increasing company-wide transportation expense per BOE over time. The run-rate of our per unit transportation cost in the Eagle Ford shale program has increased in recent quarters due to incremental compression charges and increased variable fuel costs associated with higher natural gas prices. Additionally, our transportation arrangements have changed over the periods presented to contracts that have more favorable terms for product prices but also include higher transportation fees. We anticipate we will recognize fluctuations in our per unit Eagle Ford transportation run-rate over time; however, we also anticipate company-wide transportation costs on a per BOE basis to be relatively consistent with recent quarters.

G&A expense on a per BOE basis for the three and nine months ended September 30, 2013, decreased 22 percent and 17 percent, respectively, compared to the same periods in 2012, as production increased at a faster rate than our G&A expense. A portion of our G&A 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 correlate with net cash flows and therefore are subject to variability. Generally, we expect G&A on a per BOE basis to decrease, as we anticipate production will continue to increase at a faster rate than our increase in absolute G&A expense.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion ("DD&A") expense on a per BOE basis for the three and nine months ended September 30, 2013, decreased 24 percent and 11 percent, respectively, compared to the same periods in 2012. 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. Our DD&A rate has fallen largely as a result of lower finding and development costs, as well as through the utilization of our carry with Mitsui, which allows us to add reserves without incurring out-of-pocket capital costs. Additionally, in the third quarter of 2013 we began marketing for sale all of our assets in the Anadarko Basin, which decreased DD&A on a per BOE basis, as these assets were classified as held for sale, and therefore, not depleted for the majority of the third quarter of 2013.

Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2013, and 2012 and Comparison of Financial Results and Trends Between the Nine Months Ended September 30, 2013, and 2012 for additional discussion on oil, gas, and NGL production expense, DD&A, and G&A expense.
Please refer to Note 9 - Earnings per Share in Part I, Item 1 of this report for additional discussion on the types of shares included in our basic and diluted net income (loss) per common share calculations. We recorded a net loss for the three months ended September 30, 2012. Consequently, our in-the-money stock options, unvested RSUs, and contingent PSUs were anti-dilutive for the three months ended September 30, 2012, resulting in an increase in the diluted weighted-average common shares outstanding between the two periods.

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Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2013, and 2012

Oil, gas, and NGL production revenue. The following table presents the regional changes in our production and oil, gas, and NGL revenues and costs between the three months ended September 30, 2013, and 2012:

	Average Net Daily Production Added (Lost)	Oil, Gas, & NGL Revenue Added	Production Costs Increase (Decrease)
	(MBOE/d)	(in millions)	(in millions)
South Texas & Gulf Coast	33.7	$143.4	$42.1
Mid-Continent	(4.7)	9.3	(2.0)
Permian	1.5	17.8	5.5
Rocky Mountain	5.0	57.4	10.9
Total	35.5	$227.9	$56.5

The largest regional production increase between the two periods occurred in the South Texas & Gulf Coast region as a result of drilling activity in our Eagle Ford shale program. Production in our Eagle Ford shale program continues to increase, and we expect it to continue to do so. The increase in oil and gas prices caused an increase in oil, gas, and NGL production revenue in our Mid-Continent region between the three months ended September 30, 2013, and 2012, despite a decrease in production volumes.

The following table summarizes the realized prices we received for the three months ended September 30, 2013, and 2012, before the effects of derivative cash settlements:

	For the Three Months Ended September 30,	
	2013	2012
Realized oil price ($/Bbl)	$96.44	$83.98
Realized gas price ($/Mcf)	$3.81	$3.05
Realized NGL price ($/Bbl)	$34.01	$34.82
Realized equivalent price ($/BOE)	$47.13	$39.36

A 34 percent increase in production on a BOE basis combined with a 20 percent increase in the realized price per BOE resulted in a 61 percent increase in revenue between the two periods. Based on current levels of activity, we expect production volumes to continue to increase. We also expect our realized prices to trend with commodity prices.

Realized hedge gain (loss). We recorded a net realized hedge loss of $489,000 for the three months ended September 30, 2013, compared with a net realized hedge gain of $501,000 for the same period in 2012. These amounts are comprised of realized cash settlements on commodity derivative contracts that were designated as cash flow hedges and were previously recorded in AOCIL. As of September 30, 2013, all commodity derivative contracts that had been previously designated as cash flow hedges have been reclassified into earnings from AOCIL. Our realized oil, gas, and NGL hedge gains and losses are a function of commodity prices at the time of settlement compared with the respective derivative contract prices.

Loss on divestiture activity. We recorded a $6.2 million loss on divestiture activity due largely to the write-down of certain assets held for sale to their fair value for the three months ended September 30, 2013. We recorded an $8.5 million net loss for the same period in 2012, as a result of an unsuccessful divestiture of properties, the write-down of certain assets held for sale to their fair value, and a net loss on completed divestitures. We will continue to evaluate our portfolio to determine whether there are non-strategic properties that are candidates for divestiture.

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Other operating revenues and expenses. These line items are comprised primarily of marketed gas system revenue and expense. Marketed gas system revenue increased $2.3 million to $15.6 million for the three months ended September 30, 2013, compared with $13.3 million for the same period of 2012. Concurrent with this increase, marketed gas system expense increased $3.1 million to $14.2 million for the three months ended September 30, 2013, compared with $11.1 million for the same period of 2012. The decrease in our net margin is due to an increase in gathering fees paid to third parties, which went into effect in the second half of 2012. We expect that marketed gas system revenue and expense will continue to correlate with increases and decreases in production and our realized gas price. Additionally, for the three months ended September 30, 2013, other operating expense included an additional $3.6 million of expense for an estimated liability recorded in the second quarter of 2013 as a result of ongoing discussions to clarify the royalty payment provisions of various leases on certain South Texas & Gulf Coast acreage. Please refer to Comparison of Financial Results and Trends Between the Nine Months Ended September 30, 2013, and 2012 for additional discussion.

Oil, gas, and NGL production expense. Total production costs increased 55 percent to $158.9 million for the three months ended September 30, 2013, compared with $102.4 million for the same period of 2012, as a result of a 34 percent increase in net production volumes on an equivalent basis, as well as an overall increase in costs driven largely by higher transportation costs in our South Texas & Gulf Coast region. Please refer to the caption A three-month and nine-month overview of selected production and financial information, including trends above for discussion of production costs on a per BOE basis.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A expense increased two percent to $195.8 million for the three-month period ended September 30, 2013, compared with $192.4 million for the same period in 2012, as a result of the continued development of our Eagle Ford and Bakken/Three Forks assets and the associated growth in our production, partially offset by our Anadarko Basin properties being held for sale at the beginning of the third quarter of 2013. Please refer to the caption A three-month and nine-month overview of selected production and financial information, including trends above for discussion of DD&A on a per BOE basis.

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

	For the Three Months Ended September 30,	
	2013	2012
	(in millions)	
Geological and geophysical expenses	$0.9	$1.4
Exploratory dry hole expense	—	10.4
Overhead and other expenses	15.4	13.6
Total	$16.3	$25.4

Exploration expense for the three months ended September 30, 2013, decreased 36 percent compared to the same period in 2012 due to higher exploratory dry hole expense recorded in the third quarter of 2012 as a result of a shift in our exploratory efforts in our Permian region. An exploratory project resulting in non-commercial quantities of oil, gas, or NGLs is deemed an exploratory dry hole and impacts the amount of exploration expense we record. We currently expect to expand our exploration program, which will create increased potential for exploratory dry holes.

Impairment of proved properties. We recorded a $5.9 million impairment of proved properties expense for the three months ended September 30, 2013, related to our decision to no longer pursue the development of certain underperforming assets. We had no proved property impairments during the third quarter of 2012. We expect impairments of proved properties to be more likely to occur in periods of low commodity prices.

Abandonment and impairment of unproved properties. We recorded abandonment and impairment of unproved properties expense of $3.8 million for the three months ended September 30, 2013, related to acreage we no longer intended to develop. There was minimal expense recorded in the third quarter of 2012. We expect our abandonment and impairment of unproved properties expense to trend with any lease expirations. Unsuccessful exploratory activities may also result in impairments of unproved properties.

General and administrative. G&A expense increased five percent to $33.9 million for the three months ended September 30, 2013, compared with $32.2 million for the same period of 2012. The increase is due to an increase in employee headcount, which increased overall compensation and benefits expense. Please refer to the caption A three-month and nine-month overview of selected production and financial information, including trends above for discussion of G&A expense on a per BOE basis.

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Change in Net Profits Plan liability. This non-cash expense generally relates to the change in the estimated value of the associated noncurrent liability between reporting periods. For the three months ended September 30, 2013, we recorded a non-cash expense of $940,000, compared to a non-cash expense of $798,000 for the same period in 2012. The change in our liability is subject to estimation and may change from period to period based on assumptions used for production rates, reserve quantities, commodity pricing, discount rates, and production costs. Payments made to participants as a result of divestitures and ongoing operations will also impact our liability. Please refer to Note 11 - Fair Value Measurements in Part I, Item 1 of this report for additional discussion. We broadly expect the change in our Net Profits Plan liability to trend with changes in commodity prices.

Derivative (gain) loss. We recognized a derivative loss of $39.9 million for the three-month period ended September 30, 2013, compared to a loss of $55.9 million for the same period in 2012. Commodity strip prices increased in both periods resulting in less favorable derivative positions. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional discussion.

Income tax (expense) benefit. We recorded income tax expense of $42.3 million for the three-month period ended September 30, 2013, compared to a benefit of $22.7 million for the same period in 2012, resulting in effective tax rates of 37.5 percent and 37.2 percent, respectively. The significant increase in income tax expense reflects the increase in net income before income tax expense between comparable periods. The effective tax rate between periods is essentially flat. The offsetting mix of items between periods is attributable to recording a R&D credit benefit in 2012, the effect of state permanent differences, the 2013 limited effect of valuation allowances, and other permanent differences on higher forecasted income before taxes. Unless we record a cumulative impact adjustment for 2012 and 2013 R&D tax credits, we would expect this trend to continue.

Comparison of Financial Results and Trends Between the Nine Months Ended September 30, 2013, and 2012

Oil, gas, and NGL production revenue. The following table presents the regional changes in our production and oil, gas, and NGL revenues and costs between the nine months ended September 30, 2013, and 2012:

	Average Net Daily Production Added (Lost) (MBOE/d)	Oil, Gas, & NGL Revenue Added (in millions)	Production Costs Increase (Decrease) (in millions)
South Texas & Gulf Coast	32.9	$387.6	$119.9
Mid-Continent	(5.2)	25.7	(0.8)
Permian	1.3	33.4	13.3
Rocky Mountain	3.3	110.1	21.2
Total	32.3	$556.8	$153.6

Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2013, and 2012 in the above section for discussion regarding the above trends.

The following table summarizes the realized prices we received for the nine months ended September 30, 2013, and 2012, before the effects of derivative cash settlements:

	For the Nine Months Ended September 30, 2013	2012
Realized oil price ($/Bbl)	$92.93	$85.76
Realized gas price ($/Mcf)	$3.91	$2.78
Realized NGL price ($/Bbl)	$34.77	$38.53
Realized equivalent price ($/BOE)	$45.74	$39.77

A 33 percent increase in production on a BOE basis combined with a 15 percent increase in the realized price per BOE resulted in a 53 percent increase in revenue between the two periods. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2013, and 2012 in the above section for discussion regarding the above trends.

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Realized hedge gain (loss). We recorded a net realized hedge loss of $1.8 million for the nine months ended September 30, 2013, compared with a net realized hedge gain of $2.3 million for the same period in 2012. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2013, and 2012 above for additional discussion.

Loss on divestiture activity. We recorded a $510,000 loss on divestiture activity for the nine months ended September 30, 2013, compared with a $31.2 million loss for the same period in 2012. The loss on divestiture activity in both periods is driven largely by the write-down of certain assets held for sale to their fair values, which are partially offset by gains on completed divestitures. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2013, and 2012 above for additional discussion.

Other operating revenues and expenses. These line items are comprised primarily of marketed gas system revenue and expense. Marketed gas system revenue increased $6.1 million to $48.5 million for the nine months ended September 30, 2013, compared with $42.4 million for the same period of 2012. Concurrent with this increase, marketed gas system expense increased $7.9 million to $46.0 million for the nine months ended September 30, 2013, compared with $38.1 million for the same period of 2012. Additionally, for the nine months ended September 30, 2013, other operating expense included $17.8 million of expense related to an estimated liability recorded as a result of ongoing discussions to clarify the royalty payment provisions of various leases on certain South Texas & Gulf Coast acreage.

Oil, gas, and NGL production expense. Total production costs increased 55 percent to $434.3 million for the nine months ended September 30, 2013, compared with $280.7 million for the same period of 2012, as a result of a 33 percent increase in net production volumes on a per BOE basis, as well as an overall increase in transportation costs in our South Texas & Gulf Coast region. Please refer to the caption A three-month and nine month overview of selected production and financial information, including trends above for discussion of production costs on a per BOE basis.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A expense increased 18 percent to $620.2 million for the nine-month period ended September 30, 2013, compared with $523.6 million for the same period in 2012, as a result of the continued development of our Eagle Ford and Bakken/Three Forks assets and the associated growth in our production. Please refer to the caption A three-month and nine-month overview of selected production and financial information, including trends above for discussion of DD&A on a per BOE basis.

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

	For the Nine Months Ended September 30,	
	2013	2012
	(in millions)	
Geological and geophysical expenses	$3.2	$6.8
Exploratory dry hole expense	5.9	18.6
Overhead and other expenses	43.2	40.6
Total	$52.3	$66.0

Exploration expense for the nine months ended September 30, 2013, decreased 21 percent compared to the same period in 2012 due to decreased geological and geophysical expenses as a result of a seismic study conducted in the first quarter of 2012 and decreased exploratory dry hole expenses recorded in 2013, partially offset by an increase in exploration overhead in 2013. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2013, and 2012 above for additional discussion.

Impairment of proved properties. We recorded impairment of proved properties expense of $61.7 million for the nine months ended September 30, 2013, related to our decision to no longer pursue the development of certain underperforming assets, and our plugging and abandonment program for our Olmos interval, dry gas assets in our

South Texas & Gulf Coast region. We recorded impairment of proved properties expense of $38.5 million for the nine months ended September 30, 2012, related to our Haynesville shale assets. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2013, and 2012 above for additional discussion.

Abandonment and impairment of unproved properties. We recorded abandonment and impairment of unproved properties expense of $8.5 million for the nine months ended September 30, 2013, compared with $11.3 million for the same period in 2012, the majority of which related to acreage that we no longer intend to develop. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2013, and 2012 above for additional discussion.

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General and administrative. G&A expense increased 11 percent to $101.6 million for the nine months ended September 30, 2013, compared with $91.4 million for the same period of 2012. Please refer to the captions Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2013, and 2012 and A three-month and nine-month overview of selected production and financial information, including trends above for additional discussion.
Change in Net Profits Plan liability. For the nine months ended September 30, 2013, we recorded a non-cash benefit of $6.4 million compared to a non-cash benefit of $17.3 million for the same period in 2012. The decrease in strip prices for oil, gas, and NGLs during the nine months ended September 30, 2013, was not as significant as the decrease in the comparable period in 2012. Please refer to the caption Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2013, and 2012 above for additional discussion.

Derivative (gain) loss. We recognized a derivative gain of $14.7 million for the nine-month period ended September 30, 2013, and a gain of $40.0 million for the same period in 2012 due to a decline in commodity strip pricing during each period. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional discussion.

Income tax (expense) benefit. We recorded income tax expense of $98.9 million for the nine-month period ended September 30, 2013, compared to expense of $7.7 million for the same period in 2012, resulting in effective tax rates of 37.6 percent and 37.5 percent, respectively. The significant increase in income tax expense reflects the increase in net income before income tax expense between comparable periods. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2013, and 2012 above for additional discussion.

Overview of Liquidity and Capital Resources

We believe we have sufficient liquidity and capital resources to execute our business plans for the foreseeable future. We continue to manage the duration and level of our drilling and completion service commitments in order to provide flexibility to reduce activity and capital expenditures in periods of prolonged commodity price decline.

Sources of Cash

We currently expect our remaining 2013 capital program to be funded by cash flows from operations and divestiture proceeds, with any anticipated shortfall to be funded by borrowings under our credit facility. Although we anticipate cash flow from these sources will be sufficient to fund our remaining expected 2013 capital program, we may also elect to access the capital markets, and we will continue to evaluate our portfolio of assets to identify potential divestiture candidates.

Our primary sources of liquidity are the cash flows provided by our operating activities, borrowings under our credit facility, proceeds received from divestitures of properties, and other financing alternatives, including accessing capital markets. From time to time, we may enter into carrying cost funding and sharing arrangements with third parties for particular exploration and/or development programs. All of our sources of liquidity can be impacted by the general condition of the broader economy and by fluctuations in commodity prices, operating costs, and volumes produced, all of which affect us and our industry. We have no control over the market prices for oil, gas, or NGLs, although we are able to influence the amount of our realized revenues from our oil, gas, and NGL sales through the use of derivative contracts as part of our commodity price risk management program. Historically, decreases in commodity prices have limited our industry's access to capital markets. The borrowing base under our credit facility could be reduced as a result of lower commodity prices, divestitures of proved properties, or newly issued debt. See Credit Facility below for a discussion of the amendment to our credit facility during the second quarter of 2013.

In the second quarter of 2013, we issued $500.0 million in aggregate principal amount of 2024 Notes and used the net proceeds to reduce outstanding amounts under our credit facility. In late 2011, we consummated our Acquisition and Development Agreement with Mitsui, pursuant to which Mitsui funds, or carries, 90 percent of certain drilling and completion costs attributable to our remaining interest in our non-operated Eagle Ford shale acreage until $680.0 million has been expended on our behalf. Of the original $680.0 million carry amount, approximately $493.9 million had been spent as of September 30, 2013. The remaining carry is expected to be used throughout 2013 and into the first half of 2014. Please refer to Note 12 - Acquisition and Development Agreement and Carry and Earning Agreement in our 2012 Form 10-K, under Part II, Item 8 for additional discussion.

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

Credit Facility

During the second quarter of 2013, we and our lenders entered into a Fifth Amended and Restated Credit Agreement, which replaced our previous credit facility. The credit facility has a maximum loan amount of $2.5 billion, current aggregate lender commitments of $1.3 billion, and a maturity date of April 12, 2018. The borrowing base under the credit facility as of the filing date of this report is $2.2 billion and is subject to regular semi-annual redeterminations. We believe the current commitment amount is sufficient to meet our anticipated liquidity and operating needs. Through the filing date of this report, we have experienced no issues utilizing our credit facility. No individual bank participating in our credit facility represents more than 10 percent of the lending commitments under the credit facility. Borrowings under our credit facility are secured by mortgages on the majority of our oil and gas properties. Please refer to Note 5 - Long-term Debt in Part I, Item 1 of this report for additional discussion as well as the presentation of the outstanding balance, total amount of letters of credit, and available borrowing capacity under our credit facility as of September 30, 2013, and October 23, 2013.

We are subject to customary covenants under our credit facility, including limitations on dividend payments and requirements to maintain certain financial ratios, which include debt to EBITDAX, as defined by our credit agreement as the ratio of debt to 12-month trailing EBITDAX, of less than 4.0 and an adjusted current ratio, as defined by our credit agreement, of no less than 1.0. Please refer to the caption Non-GAAP Financial Measures below for our definition of EBITDAX. As of September 30, 2013, our debt to EBITDAX ratio and adjusted current ratio were 1.2 and 2.6, respectively. As of the filing date of this report, we are in compliance with all financial and non-financial covenants under our credit facility.

Our daily weighted-average credit facility balance was $72.8 million and $157.3 million for the three months ended September 30, 2013, and 2012, respectively. Our daily weighted-average credit facility balance was $239.2 million, and $131.5 million for the nine months ended September 30, 2013, and 2012, respectively. We used the proceeds from our 2024 Notes to reduce our credit facility balance at the end of the second quarter of 2013. Our average credit facility balance was lower throughout 2012 as a result of our 2021 Notes issued at the end of 2011 and our 2023 Notes issued at the end of the second quarter of 2012, because proceeds from both issuances were used to pay down our credit facility balance. Cash flows provided by our operating activities, proceeds received from divestitures of properties, and the amount of our capital expenditures also impact the amount we have borrowed under our credit facility.

Weighted-Average Interest Rates

Our weighted-average interest rates in the current year include both paid and accrued interest payments, cash fees on the unused portion of the credit facility’s aggregate commitment amount, letter of credit fees, and amortization of deferred financing costs. Additionally, our 2012 weighted-average interest rate includes amortization of the debt discount related to our 3.50% Senior Convertible Notes. Our weighted-average borrowing rate is calculated using only our paid and accrued interest and fees.

The following table presents our weighted-average interest rates and our weighted-average borrowing rates for the three and nine months ended September 30, 2013, and 2012:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
Weighted-average interest rate	6.5 %	6.6 %	6.2 %	6.5 %
Weighted-average borrowing rate	5.9 %	6.0 %	5.6 %	5.5 %

Our weighted-average interest rates and weighted average borrowing rates in 2012 and 2013 have been impacted by the settlement of our 3.50% Senior Convertible Notes in the second quarter of 2012, the issuance of the 2023 Notes in the second quarter of 2012, and the issuance of the 2024 Notes in the second quarter of 2013. Each of these events impacted the average balance on our revolving credit facility, as well as the fees paid on the unused portion of our aggregate commitment.

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Uses of Cash

We use cash for the acquisition, exploration, and development of oil and gas properties and for the payment of operating and G&A costs, income taxes, dividends, and debt obligations, including interest. Expenditures for the exploration and development of oil and gas properties are the primary use of our capital resources. In the first nine months of 2013, we spent $1.2 billion for exploration and development capital activities and proved and unproved oil and gas property acquisitions. These amounts differ from the cost incurred amounts, which are accrual-based and include asset retirement obligation, G&G, and exploration overhead amounts.

The amount and allocation of future capital expenditures will depend upon a number of factors, including the number and size of available acquisition and drilling opportunities, our cash flows from operating, investing, and financing activities, and our ability to assimilate acquisitions and execute our drilling program. In addition, the impact of oil, gas, and NGL prices on investment opportunities, the availability of capital, and the timing and results of our operated and non-operated development and exploratory activities may lead to changes in funding requirements for future development. We periodically review our capital expenditure budget to assess changes in current and projected cash flows, acquisition and divestiture activities, debt requirements, and other factors.

We may from time to time repurchase certain amounts of our outstanding debt securities for cash and/or through exchanges for other securities. Such repurchases or exchanges may be made in open market transactions, privately negotiated transactions, or otherwise. Any such repurchases or exchanges will depend on prevailing market conditions, our liquidity requirements, contractual restrictions, compliance with securities laws, and other factors. The amounts involved in any such transaction may be material.

As of the filing date of this report, we could repurchase up to 3,072,184 shares of our common stock under our stock repurchase program, subject to the approval of our Board of Directors. Shares may be repurchased from time to time in the open market, or in privately negotiated transactions, subject to market conditions and other factors, including certain provisions of our credit facility, the indentures governing our Senior Notes, compliance with securities laws, and the terms and provisions of our stock repurchase program. Our Board of Directors reviews this program as part of the allocation of our capital. We currently do not plan to repurchase any shares in 2013.

The following table presents changes in cash flows between the nine-month periods ended September 30, 2013, and 2012. The analysis following the table should be read in conjunction with our condensed consolidated statements of cash flows in Part I, Item 1 of this report.

	For the Nine Months Ended September 30,		Amount Change Between Periods	Percent Change Between Periods
	2013	2012		
	(in millions)			
Net cash provided by operating activities	$1,000.9	$653.6	$347.3	53 %
Net cash used in investing activities	$(1,166.4)	$(1,083.7)	$(82.7)	8 %
Net cash provided by financing activities	$159.8	$311.1	$(151.3)	(49)%

Analysis of Cash Flow Changes Between the Nine Months Ended September 30, 2013, and 2012

Operating activities. Cash received from oil, gas, and NGL production revenues, including derivative cash settlements, increased $493.9 million, or 46 percent, to $1.6 billion for the first nine months of 2013, compared to the same period in 2012. This increase was due to an increase in production volumes and an increase in our adjusted realized price. Cash paid for LOE increased $30.5 million to $166.4 million for the first nine months of 2013, compared to the same period in 2012, due to increased production. Cash paid for interest, net of capitalized interest, during the first nine months of 2013 increased $18.4 million compared to the same period in 2012, due to interest paid on our 2023 Notes in the first and third quarters of 2013, offset partially by interest no longer paid on the 3.50% Senior Convertible Notes that we settled in April 2012.

Investing activities. Capital expenditures for the first nine months of 2013, including acquisition of proved and unproved oil and gas properties, increased $51.0 million, or five percent, compared with the same period in 2012. This increase is primarily a result of our completed acquisition of proved and unproved properties in our Rocky Mountain region in the second quarter of 2013.

Financing activities. We received $490.3 million of net proceeds from the issuance of our 2024 Notes in the second quarter of 2013, compared with $392.2 million of net proceeds from the issuance of our 2023 Notes in the second quarter of 2012. These proceeds were used to reduce our outstanding credit facility balance. We had net payments under our credit facility of $312.0 million during the nine months ended September 30, 2013, compared with net borrowings of $228.0 million made during the same period in 2012. During the second quarter of 2012, we paid $287.5 million to settle our 3.50% Senior Convertible Notes.

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Interest Rate Risk and Commodity Price Risk

Our credit agreement allows us to fix the interest rate for all or a portion of the principal balance of our revolving credit facility for a period up to six months; however, our borrowings are generally made with interest rates fixed for one month. Therefore, to the extent we do not repay the principal, our borrowings are rolled over and the interest rate is reset based on the current LIBOR or ABR rate as applicable. As a result, changes in interest rates can impact results of operations and cash flows. Changes in interest rates do not impact the amount of interest we pay on our fixed-rate Senior Notes, but can impact their fair market values. As of September 30, 2013, we had $28.0 million of floating-rate debt outstanding, and $1.6 billion of fixed-rate debt outstanding. The carrying amount of our floating-rate debt at September 30, 2013, approximates its fair value. Please refer to Note 11 - Fair Value Measurements in Part I, Item 1 of this report for additional discussion on the fair value of our Senior Notes.

The prices we receive for our oil, gas, and NGL production heavily impact our revenue, overall profitability, access to capital and future rate of growth. Oil, gas, and NGL prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil, gas, and NGLs have been volatile, and these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control.

We enter into commodity derivative contracts in order to reduce the impact of fluctuations in commodity prices. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information about our oil, gas, and NGL derivative contracts.

There has been no material change to the interest rate risk analysis or oil and gas price sensitivity analysis previously disclosed. Please refer to the corresponding section under Part II, Item 7 of our 2012 Form 10-K.

Off-Balance Sheet Arrangements

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

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

Critical Accounting Policies and Estimates

Please refer to the corresponding section in Part II, Item 7 of our 2012 Form 10-K and to the footnote disclosures included in Part I, Item 1 of this report for a discussion of our accounting policies and estimates.

New Accounting Pronouncements

Please refer to Note 2 - Basis of Presentation, Significant Accounting Policies, and Recently Issued Accounting Standards under Part I, Item 1 of this report for new accounting matters.

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Non-GAAP Financial Measures

EBITDAX represents income (loss) before interest expense, interest income, income taxes, depreciation, depletion, amortization and accretion, exploration expense, property impairments, non-cash stock compensation expense, derivative gains and losses net of cash settlements, change in the Net Profit Plan liability, and gains and losses on divestitures. EBITDAX excludes certain items that we believe affect the comparability of operating results and can exclude items that are generally one-time or whose timing and/or amount cannot be reasonably estimated. EBITDAX is a non-GAAP measure that is presented because we believe that it provides useful additional information to investors, as a performance measure, for analysis of our ability to internally generate funds for exploration, development, acquisitions, and to service debt. We are also subject to financial covenants under our credit facility based on our debt to EBITDAX ratio. In addition, EBITDAX is widely used by professional research analysts and others in the valuation, comparison, and investment recommendations of companies in the oil and gas exploration and production industry, and many investors use the published research of industry research analysts in making investment decisions. EBITDAX should not be considered in isolation or as a substitute for net income (loss), income (loss) from operations, net cash provided by (used in) operating activities, profitability, or liquidity measures prepared under GAAP. Because EBITDAX excludes some, but not all items that affect net income (loss) and may vary among companies, the EBITDAX amounts presented may not be comparable to similar metrics of other companies. The following table provides a reconciliation of our net income to EBITDAX and from EBITDAX to net cash provided by operating activities for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in thousands)			
Net income (loss) (GAAP)	$70,690	$(38,336)	$163,939	$12,889
Interest expense	24,488	18,362	65,170	45,352
Interest income	(28)	(126)	(64)	(201)
Income tax (benefit) expense	42,334	(22,736)	98,921	7,740
Depreciation, depletion, amortization, and asset retirement obligation liability accretion	195,792	192,432	620,232	523,610
Exploration [(1)]	14,176	25,417	45,783	66,031
Impairment of proved properties	5,935	—	61,706	38,523
Abandonment and impairment of unproved properties	3,818	447	8,459	11,296
Stock-based compensation expense	7,427	9,359	25,495	21,731
Derivative (gain) loss	39,933	55,856	(14,685)	(40,040)
Derivative cash settlement gain (loss)	(1,288)	10,921	12,715	32,803
Change in Net Profits Plan liability	940	798	(6,423)	(17,342)
Loss on divestiture activity	6,216	8,532	510	31,246
EBITDAX (Non-GAAP)	410,433	260,926	1,081,758	733,638
Interest expense	(24,488)	(18,362)	(65,170)	(45,352)
Interest income	28	126	64	201
Income tax benefit (expense)	(42,334)	22,736	(98,921)	(7,740)
Exploration	(14,176)	(25,417)	(45,783)	(66,031)
Exploratory dry hole expense	(8)	10,353	5,878	18,551
Amortization of debt discount and deferred financing costs	1,474	1,076	3,914	5,692
Deferred income taxes	42,380	(22,910)	98,619	7,305
Plugging and abandonment	(3,707)	(288)	(7,453)	(1,804)
Other	(2,840)	1,773	2,929	906
Changes in current assets and liabilities	37,752	13,285	25,034	8,220
Net cash provided by operating activities (GAAP)	$404,514	$243,298	$1,000,869	$653,586

(1) Stock-based compensation expense is a component of exploration expense and general and administrative expense on the accompanying statements of operations. Therefore, the exploration line items shown in the reconciliation above will vary from the amount shown on the accompanying statements of operations because of the component of stock-based compensation expense recorded to exploration.
Note: Certain prior period amounts have been reclassified to conform to the current period presentation.

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Cautionary Information about Forward-Looking Statements

This report contains “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this report that address activities, events, or developments with respect to our financial condition, results of operations, or economic performance that we expect, believe, or anticipate will or may occur in the future, or that address plans and objectives of management for future operations, are forward-looking statements. The words “anticipate,” “assume,” “believe,” “budget,” “estimate,” “expect,” “forecast,” “intend,” “plan,” “project,” “will,” and similar ex intended to identify forward-looking statements. Forward-looking statements appear in a number of places in this report, and include statements about such matters as:

- the amount and nature of future capital expenditures and the availability of liquidity and capital resources to fund capital expenditures;
- the drilling of wells and other exploration and development activities and plans, as well as possible future acquisitions;
- the possible divestiture or farm-down of, or joint venture relating to, certain properties;
- proved reserve estimates and the estimates of both future net revenues and the present value of future net revenues associated with those proved reserve estimates;
- future oil, gas, and NGL production estimates;
- our outlook on future oil, gas, and NGL prices, well costs, and service costs;
- cash flows, anticipated liquidity, and the future repayment of debt;
- business strategies and other plans and objectives for future operations, including plans for expansion and growth of operations or to defer capital investment, and our outlook on our future financial condition or results of operations; and
- other similar matters such as those discussed in the Management’s Discussion and Analysis of Financial Condition and Results of Operations section of this report.

Our forward-looking statements are based on assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments, and other factors that we believe are appropriate under the circumstances. These statements are subject to a number of known and unknown risks and uncertainties, which may cause our actual results and performance to be materially different from any future results or performance expressed or implied by the forward-looking statements. Some of these risks are described in the Risk Factors section of our 2012 Form 10-K, and include such factors as:

- the volatility of oil, gas, and NGL prices, and the effect it may have on our profitability, financial condition, cash flows, access to capital, and ability to grow production volumes and/or proved reserves;
- the continued weakness in economic conditions and uncertainty in financial markets;
- our ability to replace reserves in order to sustain production;
- our ability to raise the substantial amount of capital that is required to replace our reserves;
- our ability to compete against competitors that have greater financial, technical, and human resources;
- our ability to attract and retain key personnel;
- the imprecise estimations of our actual quantities and present value of proved oil, gas, and NGL reserves;
- the uncertainty in evaluating recoverable reserves and estimating expected benefits or liabilities;
- the possibility that exploration and development drilling may not result in commercially producible reserves;
- our limited control over activities on non-operated properties;

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- our reliance on the skill and expertise of third-party service providers on our operated properties;
- the possibility that title to properties in which we have an interest may be defective;
- the possibility that our planned drilling in existing or emerging resource plays using some of the latest available horizontal drilling and completion techniques is subject to drilling and completion risks and may not meet our expectations for reserves or production;
- the uncertainties associated with divestitures, joint ventures, farm-downs, farm-outs and similar transactions with respect to certain assets, including whether such transactions will be consummated or completed in the form or timing and for the value that we anticipate;
- the uncertainties associated with enhanced recovery methods;
- our commodity derivative contracts may result in financial losses or may limit the prices that we receive for oil, gas, and NGL sales;
- the inability of one or more of our service providers, customers, or contractual counterparties to meet their obligations;
- our ability to deliver necessary quantities of natural gas to contractual counterparties;
- price declines or unsuccessful exploration efforts resulting in write-downs of our asset carrying values;
- the impact that lower oil, gas, or NGL prices could have on the amount we are able to borrow under our credit facility;
- the possibility that our amount of debt may limit our ability to obtain financing for acquisitions, make us more vulnerable to adverse economic conditions, and make it more difficult for us to make payments on our debt;
- the possibility that covenants in our debt agreements may limit our discretion in the operation of our business, prohibit us from engaging in beneficial transactions or lead to the accelerated payment of our debt;
- operating and environmental risks and hazards that could result in substantial losses;
- the impact of seasonal weather conditions and lease stipulations on our ability to conduct drilling activities;
- our ability to acquire adequate supplies of water and dispose of or recycle water we use at a reasonable cost in accordance with environmental rules;
- complex laws and regulations, including environmental regulations, that result in substantial costs and other risks;
- the availability and capacity of gathering, transportation, processing, and/or refining facilities;
- our ability to sell and/or receive market prices for our oil, gas, and NGLs;
- new technologies may cause our current exploration and drilling methods to become obsolete;
- the possibility of security threats, including terrorist attacks and cybersecurity breaches, against, or otherwise impacting, our facilities and systems; and
- litigation, environmental matters, the potential impact of legislation and government regulations, and the use of management estimates regarding such matters.

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this item is provided under the caption Interest Rate Risk and Commodity Price Risk in Item 2 above and is incorporated herein by reference. Please also refer to the sensitivity analysis within our 2012 Form 10-K in Part II, Item 7.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

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

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) ("Disclosure Controls") will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our Disclosure Controls are effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There have been no changes during the third quarter of 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

There have been no material changes to the legal proceedings as previously disclosed in our 2012 Form 10-K, under Part I, Item 3. See Note 6 - Commitments and Contingencies, in Part I, Item 1 of this report, for additional discussion.

ITEM 1A. RISK FACTORS

There have been no material changes to the risk factors as previously disclosed in our 2012 Form 10-K.

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

(c) The following table provides information about purchases by the Company or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the fiscal quarter ended September 30, 2013, of shares of the Company's common stock, which is the sole class of equity securities registered by the Company pursuant to Section 12 of the Exchange Act:

PURCHASES OF EQUITY SECURITIES BY ISSUER
AND AFFILIATED PURCHASERS

Period	(a) Total Number of Shares Purchased [1]	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Program	(d) Maximum Number of Shares that May Yet Be Purchased Under the Program [2]
07/01/13 - 07/31/13	266,243	$60.46	—	3,072,184
08/01/13 - 08/31/13	973	$70.10	—	3,072,184
09/01/13 - 09/30/13	146	$71.61	—	3,072,184
Total:	267,362	$60.50	—	3,072,184

(1) All shares purchased in the third quarter of 2013 were to offset tax withholding obligations that occur upon the delivery of outstanding shares underlying RSUs and PSUs delivered under the terms of grants under our Equity Incentive Compensation Plan.

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

Our payment of cash dividends to our stockholders is subject to covenants in our credit facility that limit our annual dividend payments to no more than $50.0 million per year. We are also subject to certain covenants under our Senior Notes that restrict certain payments, including dividends; provided, however, that the first $6.5 million of dividends paid each year are not restricted by these covenants. We do not anticipate that these restrictions will limit our payment of dividends at our current rate for the foreseeable future if declared by our Board of Directors.

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ITEM 6. EXHIBITS

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

Exhibit	Description
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes - Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes - Oxley Act of 2002
32.1**	Certification pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document

* Filed with this report.

** Furnished with this report.

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SIGNATURES

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

	SM ENERGY COMPANY
October 30, 2013	By: /s/ ANTHONY J. BEST Anthony J. Best Chief Executive Officer (Principal Executive Officer)
October 30, 2013	By: /s/ A. WADE PURSELL A. Wade Pursell Executive Vice President and Chief Financial Officer (Principal Financial Officer)
October 30, 2013	By: /s/ MARK T. SOLOMON Mark T. Solomon Vice President - Controller and Assistant Secretary (Principal Accounting Officer)