SM Energy Co
Form 10-Q
July 31, 2013
Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 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 July 25, 2013, the registrant had 66,928,778 shares of common stock, $0.01 par value, outstanding.

Table of Contents

SM ENERGY COMPANY
INDEX

Table of Contents

PART I. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)
(in thousands, except share amounts)

	June 30, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$176	$5,926
Accounts receivable	291,197	254,805
Refundable income taxes	2,716	3,364
Prepaid expenses and other	30,340	30,017
Derivative asset	58,071	37,873
Deferred income taxes	13,136	8,579
Total current assets	395,636	340,564
Property and equipment (successful efforts method), at cost:		
Land	1,857	1,845
Proved oil and gas properties	5,922,411	5,401,684
Less - accumulated depletion, depreciation, and amortization	(2,737,774)	(2,376,170)
Unproved oil and gas properties	234,741	175,287
Wells in progress	290,289	273,928
Materials inventory, at lower of cost or market	14,012	13,444
Oil and gas properties held for sale net of accumulated depletion, depreciation and amortization of $55,348 in 2013 and $20,676 in 2012	87,310	33,620
Other property and equipment, net of accumulated depreciation of $25,542 in 2013 and $22,442 in 2012	176,243	153,559
Total property and equipment, net	3,989,089	3,677,197
Noncurrent assets:		
Derivative asset	28,798	16,466
Restricted cash	94,311	86,773
Other noncurrent assets	82,834	78,529
Total other noncurrent assets	205,943	181,768
Total Assets	$4,590,668	$4,199,529
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$577,452	$525,627
Derivative liability	4,748	8,999
Other current liabilities	6,000	6,920
Total current liabilities	588,200	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	118,383	112,912
Asset retirement obligation associated with oil and gas properties held for sale	4,617	1,393
Net Profits Plan liability	71,464	78,827
Deferred income taxes	598,662	537,383
Derivative liability	1,525	6,645
Other noncurrent liabilities	52,914	66,357
Total noncurrent liabilities	2,475,565	2,243,517
Commitments and contingencies (note 6)		
Stockholders' equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued: 66,412,394 shares in 2013 and 66,245,816 shares in 2012; outstanding, net of treasury shares: 66,389,982 shares in 2013 and 66,195,235 shares in 2012	664	662
Additional paid-in capital	254,940	233,642
Treasury stock, at cost: 22,412 shares in 2013 and 50,581 shares in 2012	(823)	(1,221)
Retained earnings	1,280,332	1,190,397
Accumulated other comprehensive loss	(8,210)	(9,014)
Total stockholders' equity	1,526,903	1,414,466
Total Liabilities and Stockholders' Equity	$4,590,668	$4,199,529

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

Table of Contents

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Operating revenues:				
Oil, gas, and NGL production revenue	$534,520	$312,608	$1,004,095	$675,203
Realized hedge gain (loss)	(1,189)	185	(1,288)	1,837
Gain (loss) on divestiture activity	6,280	(24,176)	5,706	(22,714)
Other operating revenues	19,749	15,803	35,027	27,517
Total operating revenues	559,360	304,420	1,043,540	681,843
Operating expenses:				
Oil, gas, and NGL production expense	149,737	91,134	275,370	178,266
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	225,731	161,608	424,440	331,178
Exploration	20,657	22,007	36,055	40,614
Impairment of proved properties	34,552	38,523	55,771	38,523
Abandonment and impairment of unproved properties	4,339	10,707	4,641	10,849
General and administrative	35,374	31,130	67,654	59,272
Change in Net Profits Plan liability	(5,438)	(22,079)	(7,363)	(18,140)
Unrealized and realized derivative gain	(85,190)	(98,112)	(54,618)	(95,896)
Other operating expenses	35,314	17,111	51,108	28,561
Total operating expenses	415,076	252,029	853,058	573,227
Income from operations	144,284	52,391	190,482	108,616
Non-operating income (expense):				
Interest income	24	5	36	75
Interest expense	(21,581)	(12,712)	(40,682)	(26,990)
Income before income taxes	122,727	39,684	149,836	81,701
Income tax expense	(46,205)	(14,795)	(56,587)	(30,476)
Net income	$76,522	$24,889	$93,249	$51,225
Basic weighted-average common shares outstanding	66,295	64,585	66,254	64,345
Diluted weighted-average common shares outstanding	67,893	67,556	67,711	67,806
Basic net income per common share	$1.15	$0.39	$1.41	$0.80
Diluted net income per common share	$1.13	$0.37	$1.38	$0.76
Dividends per common share	$—	$—	$0.05	$0.05

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

4

Table of Contents

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Net income	$76,522	$24,889	$93,249	$51,225
Other comprehensive income (loss), net of tax:				
Reclassification to earnings [(1)]	746	(116)	807	(1,150)
Pension liability adjustment	—	—	(3)	—
Total other comprehensive income (loss), net of tax	746	(116)	804	(1,150)
Total comprehensive income	$77,268	$24,773	$94,053	$50,075

[(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.

Table of Contents

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

	For the Six Months Ended June 30,	
	2013	2012
Cash flows from operating activities:		
Net income	$93,249	$51,225
Adjustments to reconcile net income to net cash provided by operating activities:		
(Gain) loss on divestiture activity	(5,706)	22,714
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	424,440	331,178
Exploratory dry hole expense	5,886	8,198
Impairment of proved properties	55,771	38,523
Abandonment and impairment of unproved properties	4,641	10,849
Stock-based compensation expense	18,068	12,372
Change in Net Profits Plan liability	(7,363)	(18,140)
Unrealized derivative gain	(40,615)	(74,014)
Amortization of debt discount and deferred financing costs	2,440	4,616
Deferred income taxes	56,239	30,215
Plugging and abandonment	(3,746)	(1,516)
Other	5,769	(867)
Changes in current assets and liabilities:		
Accounts receivable	(59,284)	735
Refundable income taxes	648	2,978
Prepaid expenses and other	(680)	(4,759)
Accounts payable and accrued expenses	46,598	(4,019)
Net cash provided by operating activities	596,355	410,288
Cash flows from investing activities:		
Net proceeds from sale of oil and gas properties	20,343	15,410
Capital expenditures	(733,992)	(705,366)
Acquisition of proved and unproved oil and gas properties	(59,201)	(5,312)
Other	(4,940)	111
Net cash used in investing activities	(777,790)	(695,157)
Cash flows from financing activities:		
Proceeds from credit facility	516,500	802,500
Repayment of credit facility	(828,500)	(741,500)
Deferred financing costs related to credit facility	(3,444)	—
Net proceeds from 5.0% Senior Notes Due 2024	490,820	—
Net proceeds from 6.50% Senior Notes Due 2023	—	392,336
Repayment of 3.50% Senior Convertible Notes	—	(287,500)
Proceeds from sale of common stock	3,652	2,888
Dividends paid	(3,314)	(3,208)
Other	(29)	343
Net cash provided by financing activities	175,685	165,859
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.

Table of Contents

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

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

	For the Six Months Ended June 30,	
	2013	2012
	(in thousands)	
Cash paid for interest, net of capitalized interest	$(36,089)	$(30,137)
Net cash refunded for income taxes	$332	$2,815

As of June 30, 2013, and 2012, $243.5 million and $226.0 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.

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

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, ("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 June 30, 2013, through the filing date of this report.

Significant Accounting Policies

The accounting policies followed by the Company are set forth in Note 1 to the Company's consolidated financial statements in the 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 authoritative accounting guidance and assessing its impact on the Company's financial statements and disclosures.

Table of Contents

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 June 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 costs to sell. Subsequent changes to the estimated fair value less the cost to sell will impact the measurement of assets held for sale for which fair value less costs to sell is determined to be less than the carrying value of the assets.

As of June 30, 2013, the accompanying condensed consolidated balance sheets (“accompanying balance sheets”) present $87.3 million of assets held for sale, net of accumulated depletion, depreciation, and amortization expense. A corresponding asset retirement obligation liability of $4.6 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 are reflected in the gain (loss) on divestiture activity line item in the accompanying condensed consolidated statements of operations (“accompanying statements of operations”).

Subsequent to June 30, 2013, the Company began the marketing of certain assets in its Mid-Continent region. The Company expects the marketing of these assets to take approximately six months. These assets were not classified as held for sale as of June 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 six months ended June 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 June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
	(in thousands)			
Current portion of income tax expense (benefit):				
Federal	$—	$—	$—	$—
State	246	(132)	348	261
Deferred portion of income tax expense	45,959	14,927	56,239	30,215
Total income tax expense	$46,205	$14,795	$56,587	$30,476
Effective tax rate	37.6%	37.3%	37.8%	37.3%

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. The 2013 increase in the effective rate from 2012 primarily reflects changes in the mix of the highest marginal state tax rates, the effects of valuation allowance adjustments, and the state tax rate effect on year-to-date net income, all of which have been partially offset by changes in enacted state rates for North Dakota, Texas, and New Mexico.

Table of Contents

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 has timely appealed the IRS' conclusions and maintains it is entitled to the claimed credits.

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. This credit facility replaced the Company's 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 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. 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 October 1, 2013. Borrowings under the facility are secured by substantially all of the Company's proved oil and gas properties. The Company has incurred approximately $3.4 million in additional deferred financing costs in association with the amendment and extension of this credit facility.

The Company must comply with certain financial and non-financial covenants under the terms of its credit facility agreement, including the limitation of the Company's dividends to no more than $50.0 million per year. The Company was in compliance with all financial covenants under the credit facility as of the filing date of this report. The amended credit facility includes the same borrowing base utilization grid as was stated 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 July 25, 2013, June 30, 2013, and December 31, 2012:

	As of July 25, 2013	As of June 30, 2013	As of December 31, 2012
	(in millions)		
Credit facility balance	$85.0	$28.0	$340.0
Letters of credit [1]	$0.8	$0.8	$0.8
Available borrowing capacity	$1,214.2	$1,271.2	$659.2

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

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 $490.8 million after deducting fees of $9.2 million, which will be 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.

Table of Contents

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. However, the first $6.5 million of dividends paid each year are not restricted by this covenant. The Company was in compliance with all covenants under its 2024 Notes as of June 30, 2013.

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 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

There have been no material changes from the commitments disclosed in the notes to the Company's consolidated financial statements included in the 2012 Form 10-K.

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 both 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 court has not yet ruled on Chieftain's motion to certify the putative class, and has stayed all proceedings until the United States Court of Appeals for the Tenth Circuit issues its ruling 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. As of the filing date of this report, this matter remains stayed.

Table of Contents

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, the Company recorded an estimated liability of $14.2 million related to ongoing discussions to clarify the royalty payment provisions of various leases on certain South Texas & Gulf Coast acreage.

Note 7 - Compensation Plans

Cash Bonus Plan

During the first six 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 $5.3 million and $4.6 million of accrued cash bonus plan expense for the three-month periods ended June 30, 2013, and 2012, respectively, and $10.9 million and $9.3 million for the six-month periods ended June 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 June 30, 2013, and 2012, was $3.3 million and $1.4 million, respectively, and $6.3 million and $2.6 million for the six-month periods ended June 30, 2013, and 2012, respectively. As of June 30, 2013, there was $7.7 million of total unrecognized compensation expense related to unvested RSU awards, which is being amortized through 2015. There have been no material changes to the outstanding and non-vested RSUs during the first half of 2013.

Subsequent to June 30, 2013, the Company granted 327,605 RSUs as part of its regular annual long-term equity compensation program. These RSUs will vest 1/3rd on each of the next three anniversary dates of the grant. Also subsequent to June 30, 2013, the Company settled 201,501 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 135,389 net shares of common stock. The remaining 66,112 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 June 30, 2013, and 2012, was $5.0 million and $5.2 million, respectively, and $9.7 million and $8.1 million for the six-month periods ended June 30, 2013, and 2012, respectively. As of June 30, 2013, there was $9.8 million of total unrecognized compensation expense related to unvested PSUs to be amortized through 2015. There have been no material changes to the outstanding and non-vested PSUs during the first half of 2013.

Table of Contents

Subsequent to June 30, 2013, the Company granted 274,831 PSUs as part of its regular annual long-term equity compensation program. These PSUs will fully vest on the third anniversary of the date of the grant. Also subsequent to June 30, 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, 200,050 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon delivery of the shares underlying those PSUs.

Stock Option Grants Under the Equity Incentive Compensation Plan

A summary of activity associated with the Company's Stock Option Plan for the six months ended June 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	(121,318)	$13.85	$5,638
Forfeited	—	$—	
Outstanding, at end of quarter	146,528	$15.84	$6,378
Vested and exercisable, at end of quarter	146,528	$15.84	$6,378

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

Director Shares

During the first half of 2013 and 2012, the Company issued 28,169 and 26,500 shares, respectively, of its common stock from treasury to its non-employee directors, under the Company's Equity Incentive Compensation Plan. The Company recorded $1.4 million and $1.1 million of compensation expense related to these awards for both the three and six months ended June 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 June 30, 2013. There were 44,437 and 37,124 shares issued under the ESPP during the second quarters of June 30, 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 June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
	(in thousands)			
General and administrative expense	$3,443	$3,682	$7,229	$8,094
Exploration expense	323	493	697	1,018
Total	$3,766	$4,175	$7,926	$9,112

Table of Contents

Additionally, the Company accrued or made cash payments under the Net Profits Plan of $2.6 million and $1.4 million for the three-month periods ended June 30, 2013, and 2012, respectively, and $2.6 million and $1.7 million for the six-month periods ended June 30, 2013, and 2012, respectively as a result of divestiture proceeds. These cash payments are accounted for as a reduction in the gain (loss) on divestiture activity in the accompanying statements of operations.

The Company records changes in the present value of estimated future payments under the Net Profits Plan as a separate line item in the accompanying statements of operations. The change in the estimated liability is recorded as a non-cash expense or benefit in the current period. The amount recorded as an expense or benefit associated with the change in the estimated liability is not allocated to 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 June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
	(in thousands)			
Service cost	$1,914	$1,515	$3,146	$2,465
Interest cost	468	393	813	689
Expected return on plan assets that reduces periodic pension costs	(483)	(352)	(769)	(572)
Amortization of prior service costs	5	9	9	9
Amortization of net actuarial loss	414	293	611	394
Net periodic benefit cost	$2,318	$1,858	$3,810	$2,985

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

Subsequent to June 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.

Table of Contents

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.

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 June 30, 2012, potentially dilutive securities for this calculation for the three and six months ended June 30, 2012, included shares into which the 3.50% Senior Convertible Notes were convertible. 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 for the three-month and six-month periods ended June 30, 2012, making them dilutive for those periods. The dilutive net income per share calculations for the three-month and six-month periods ended June 30, 2012, were 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 June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
	(in thousands, except per share amounts)			
Net income	$76,522	$24,889	$93,249	$51,225
Basic weighted-average common shares outstanding	66,295	64,585	66,254	64,345
Add: dilutive effect of stock options, unvested RSUs, and contingent PSUs	1,598	2,149	1,457	2,182
Add: dilutive effect of 3.50% Senior Convertible Notes	—	822	—	1,279
Diluted weighted-average common shares outstanding	67,893	67,556	67,711	67,806
Basic net income per common share	$1.15	$0.39	$1.41	$0.80
Diluted net income per common share	$1.13	$0.37	$1.38	$0.76

Table of Contents

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 June 30, 2013, and through the filing date of this report, the Company has commodity derivative contracts outstanding through the first quarter of 2016 for a total of 12.6 million Bbls of oil production, 167.2 million MMBtu of gas production, and 1.5 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.

The following tables summarize the approximate volumes and average contract prices of contracts the Company had in place as of June 30, 2013:

Oil Contracts

Oil Swaps

Contract Period	Volumes	Weighted-Average Contract Price
	(Bbls)	(per Bbl)
Remainder of 2013	2,383,000	$97.51
2014	2,024,000	$93.85
2015	356,000	$88.40
All oil swaps*	4,763,000	

*Oil swaps are comprised of NYMEX WTI (71%) and Argus LLS (29%).

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(Bbls)	(per Bbl)	(per Bbl)
Remainder of 2013	1,491,000	$77.88	$111.93
2014	3,022,000	$84.07	$105.46
2015	3,366,000	$85.00	$94.25
All oil collars	7,879,000		

Table of Contents

Gas Contracts

Gas Swaps

Contract Period	Volumes	Weighted-Average Contract Price
	(MMBtu)	(per MMBtu)
Remainder of 2013	40,335,000	$4.00
2014	59,384,000	$4.08
2015	33,528,000	$4.07
2016	10,331,000	$4.38
All gas swaps*	143,578,000	

*Gas swaps are comprised of IF El Paso Permian (3%), IF HSC (58%), IF NGPL TXOK (5%), IF NNG Ventura (3%), IF PEPL (13%), IF Reliant N/S (15%), IF TETCO STX (1%), and IF NGPL MidCont (2%).

Gas Collars

Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(MMBtu)	(per MMBtu)	(per MMBtu)
Remainder of 2013	3,410,000	$4.39	$5.31
2014	5,734,000	$4.38	$5.36
2015	14,480,000	$3.96	$4.30
All gas collars*	23,624,000		

*Gas collars are comprised of IF El Paso Permian (2%), IF HSC (51%), IF NGPL TXOK (6%), IF NNG Ventura (4%), IF PEPL (6%), IF Reliant N/S (17%), and IF TETCO STX (14%).

NGL Contracts

NGL Swaps

Contract Period	Volumes	Weighted-Average Contract Price
	(Bbls)	(per Bbl)
Remainder of 2013	1,077,000	$53.26
2014	404,000	$58.42
All NGL swaps*	1,481,000	

*NGL swaps are comprised of OPIS Mont. Belvieu Purity Ethane (9%), OPIS Mont. Belvieu LDH Propane (44%), OPIS Mont. Belvieu NON-LDH Isobutane (12%), OPIS Mont. Belvieu NON-LDH Normal Butane (16%), and OPIS Mont. Belvieu NON-LDH Natural Gasoline (19%).

Table of Contents

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 $80.6 million and $38.7 million at June 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 June 30, 2013			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity contracts	Current assets	$58,071	Current liabilities	$4,748
Commodity contracts	Noncurrent assets	28,798	Noncurrent liabilities	1,525
Derivatives not designated as hedging instruments		$86,869		$6,273

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

Offsetting of Derivative Assets and Liabilities

As of June 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:

	Derivative Assets		Derivative Liabilities	
	As of		As of	
Offsetting of Derivative Assets and Liabilities	June 30, 2013	December 31, 2012	June 30, 2013	December 31, 2012
	(in thousands)			

Gross amounts presented in the accompanying balance sheets	$86,869	$54,339	$(6,273)	$(15,644)
Amounts not offset in the accompanying balance sheets	(6,273)	(13,400)	6,273	13,400
Net amounts	$80,596	$40,939	$—	$(2,244)

Table of Contents

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 six-month periods ended June 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 are reclassified into earnings as the original derivative transactions settle. As of June 30, 2013, AOCIL included $308,000 of net unrealized loss, net of income tax, on commodity derivative contracts that had been previously designated as cash flow hedges, all of which will be reclassified into earnings from AOCIL during the next twelve months. Please refer to Note 11 - Fair Value Measurements for more information regarding the Company's derivative instruments, including its valuation techniques.

The following table summarizes the components of unrealized and realized derivative gain presented in the accompanying statements of operations:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
	(in thousands)			
Cash settlement (gain) loss:				
Oil contracts	$(29)	$2,371	$248	$10,670
Gas contracts	2,091	(16,252)	(7,733)	(31,464)
NGL contracts	(4,273)	(2,565)	(6,518)	(1,088)
Total cash settlement gain	$(2,211)	$(16,446)	$(14,003)	$(21,882)
Unrealized (gain) loss on change in fair value:				
Oil contracts	$(26,044)	$(92,774)	$(22,255)	$(63,283)
Gas contracts	(50,267)	29,867	(10,198)	12,233
NGL contracts	(6,668)	(18,759)	(8,162)	(22,964)
Total net unrealized gain on change in fair value	(82,979)	(81,666)	(40,615)	(74,014)
Total unrealized and realized derivative gain	$(85,190)	$(98,112)	$(54,618)	$(95,896)

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 June 30,		For the Six Months Ended June 30,	
			2013	2012	2013	2012
			(in thousands)			
Amount reclassified from AOCIL	Commodity contracts	Realized hedge gain (loss)	$746	$(116)	$807	$(1,150)

The Company realized a net hedge loss of $1.2 million and a net hedge gain of $185,000 from its commodity derivative contracts for the three months ended June 30, 2013, and 2012, respectively, and a net hedge loss of $1.3 million and a net hedge gain of $1.8 million for the six months ended June 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.

Table of Contents

Credit Related Contingent Features

As of June 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.

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 June 30, 2013:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives (1)	$—	$86,869	$—
Proved oil and gas properties (2)	$—	$—	$37,898
Unproved oil and gas properties (2)	$—	$—	$45,156
Oil and gas properties held for sale (2)	$—	$—	$15,095
Liabilities:			
Derivatives (1)	$—	$6,273	$—
Net Profits Plan (1)	$—	$—	$71,464

(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.

Table of Contents

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.

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

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

Table of Contents

If the commodity prices used in the calculation changed by five percent, the liability recorded at June 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 Six Months Ended June 30, 2013
	(in thousands)
Beginning balance	$78,827
Net increase in liability [1]	3,147
Net settlements [1] [2]	(10,510)
Transfers in (out) of Level 3	—
Ending balance	$71,464

(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 relating to divestiture proceeds of $2.6 million for the six months ended June 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, or 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 June 30, 2013, or December 31, 2012, as they are recorded at historical value.

	As of June 30, 2013	As of December 31, 2012
	(in thousands)	
2019 Notes	$368,592	$371,875
2021 Notes	$367,500	$371,070
2023 Notes	$419,000	$424,200
2024 Notes [1]	$473,125	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 interest rates are variable, based on prevailing market rates.

22

Table of Contents

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

Table of Contents

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

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

Overview of the Company, Highlights, and Outlook

General Overview

We are an independent energy company engaged in the acquisition, exploration, 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, as well as exposure to oil-focused plays in our Permian region. 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 majority 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 second quarter of 2013, we had the following financial and operational results:

- Average daily production for the three months ended June 30, 2013, was 35.5 MBbls of oil, 430.2 MMcf of gas, and 24.6 MBbls of NGLs, for a record average equivalent daily production rate of 131.8 MBOE, compared with 92.6 MBOE for the same period in 2012. Please see additional discussion below under the caption Production Results.

- Net income for the three months ended June 30, 2013, was $76.5 million, or $1.13 per diluted share, compared to net income for the three months ended June 30, 2012, of $24.9 million, or $0.37 per diluted share. Please refer to the Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2013, and 2012 for additional discussion regarding the components of net income.

- Costs incurred for oil and gas producing activities for the three months ended June 30, 2013, were $500.3 million, compared with $407.7 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 Overview of Liquidity and Capital Resources below for additional discussion on how we expect to fund our capital program.

- EBITDAX, a non-GAAP financial measure, for the three months ended June 30, 2013, was $342.5 million, compared with $213.7 million for the same period in 2012. 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.

Table of Contents

Oil, Gas, and NGL Prices

Our financial condition and the results of our operations are significantly affected by the prices we receive for 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"). 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 first and second quarters of 2013, as well as the second quarter of 2012:

	For the Three Months Ended		
	June 30, 2013	March 31, 2013	June 30, 2012
Crude Oil (per Bbl):			
Average NYMEX price	$94.14	$94.30	$93.30
Realized price	$90.00	$91.67	$82.52
Natural Gas:			
Average NYMEX price (per MMBtu)	$4.02	$3.48	$2.28
Realized price (per Mcf)	$4.28	$3.57	$2.34
Natural Gas Liquids (per Bbl):			
Average OPIS price	$37.76	$40.61	$43.71
Realized price	$34.09	$36.65	$37.79

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 likely 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 downward pressure for a long period of time due to market oversupply resulting from high levels of drilling activity and tepid economic growth, although gas prices increased moderately in the last half of 2012 and early 2013. 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 June 30, 2013, and July 25, 2013:

	As of July 25, 2013	As of June 30, 2013
NYMEX WTI oil (per Bbl)	$ 99.38	$ 93.41
NYMEX Henry Hub gas (per MMBtu)	$ 3.85	$ 3.76
OPIS NGLs (per Bbl)	$ 37.92	$ 35.62

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.

Table of Contents

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 a reconciliation from our realized price to our adjusted price for the commodities indicated, including the effects of derivative cash settlements, for the first and second quarters of 2013, as well as the second quarter of 2012:

	For the Three Months Ended		
	June 30, 2013	March 31, 2013	June 30, 2012
Crude Oil (per Bbl):			
Realized price	$90.00	$91.67	$82.52
Less the effects of derivative cash settlements	(0.36)	(0.37)	(2.00)
Adjusted price, including the effects of derivative cash settlements	$89.64	$91.30	$80.52
Natural Gas (per Mcf):			
Realized price	$4.28	$3.57	$2.34
Add (less) the effects of derivative cash settlements	(0.05)	0.33	0.68
Adjusted price, including the effects of derivative cash settlements	$4.23	$3.90	$3.02
Natural Gas Liquids (per Bbl):			
Realized price	$34.09	$36.65	$37.79
Add the effects of derivative cash settlements	1.91	1.15	1.65
Adjusted price, including the effects of derivative cash settlements	$36.00	$37.80	$39.44

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.

Table of Contents

Second Quarter 2013 Highlights and Outlook for the Remainder of 2013

Operational Activities. We now expect our capital program for 2013 to be approximately $1.65 billion, an increase from the previously disclosed $1.5 billion. The increase reflects additional capital for the acquisition of Powder River Basin acreage, as well as incremental capital for further testing and delineation of our emerging plays in East Texas and the Powder River Basin.

We now expect total Eagle Ford capital expenditures to be $655 million in 2013. In our operated Eagle Ford shale program in south Texas, we made 22 flowing completions during the second quarter of 2013. We expect to make approximately 95 flowing completions on our operated acreage, an increase from the 75 flowing completions we originally budgeted in 2013, for essentially the same amount of capital as was originally budgeted. The increase in completion count for 2013 is due to efficiency gains we achieved in the first half of the year. 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 has 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. We will continue to explore additional arrangements to facilitate the continued growth of our operated program. In our non-operated Eagle Ford program, the operator had nine drilling rigs running during the second 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 will be responsible for our proportionate share of those costs.

During the second quarter of 2013, we made 12 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. In 2013, we expect to make 40 operated flowing completions in our Bakken/Three Forks program. During the second quarter, we exchanged two traditional rigs for one walking rig that is more efficient for pad drilling. We expect to run three rigs for the rest of the year focusing on infill drilling in our three focus areas and improving efficiencies through pad drilling. For 2013, we expect to invest approximately $295 million on drilling and completion activities in our total Bakken/Three Forks program.

During the second quarter of 2013, we closed our previously announced acquisition of approximately 40,000 net acres in the Powder River Basin and now have approximately 110,000 total net acres in the basin. Of this total acreage amount, approximately 65,000, 45,000, and 15,000 net acres are prospective for the Frontier formation, the Shannon formation, and Sussex formation, respectively. We expect to operate a one rig program focused on the Frontier formation in the second half of the year.

In our Permian program, we expect to invest approximately $200 million in 2013. Our program focuses on three areas: the development of the Bone Spring formation in southeast New Mexico, the delineation of the Mississippian limestone formation in the northern Midland Basin, and the testing of various shale targets in the Midland Basin. We operated three drilling rigs during the second quarter of 2013 in our Permian region. During the second quarter, we drilled a test well in the Wolfcamp shale on our acreage in Upton County, Texas, which is currently flowing back. We plan to run a three rig program for the remainder of 2013, focusing on these three focus areas.

Our ongoing exploration effort is engaged in acquiring leasehold and testing concepts in new plays. Earlier in the year, we announced a successful exploration well test in East Texas targeting the Woodbine interval and we expect to conduct additional tests on intervals of interest including the Eagle Ford shale, Austin chalk, and Woodbine formation. Our East Texas position now totals approximately 195,000 net acres and we continue to pursue other leasing opportunities in this region.

Subsequent to June 30, 2013, we announced that we have engaged an advisor to market all of our interests in the Anadarko Basin in western Oklahoma and the Texas Panhandle. These marketed interests include our Granite Wash assets. We expect the marketing of these assets to take approximately six months. During the marketing process, we plan to continue to operate one rig focusing primarily on the Granite Wash interval.

Please refer to Overview of Liquidity and Capital Resources for additional discussion regarding how we intend to fund our 2013 capital program.

Table of Contents

Production Results. The table below provides a regional breakdown of our production for the second quarter of 2013:

	South Texas & Gulf Coast	Mid-Continent	Permian	Rocky Mountain	Total [1]
Second quarter of 2013 production:					
Oil (MMBbl)	1.1	0.1	0.5	1.6	3.2
Gas (Bcf)	26.4	10.6	0.8	1.3	39.1
NGLs (MMBbl)	2.2	—	—	—	2.2
Equivalent (MMBOE)	7.7	1.9	0.6	1.8	12.0
Avg. daily equivalents (MBOE/d)	84.6	20.8	6.6	19.8	131.8
Relative percentage	64 %	16 %	5 %	15 %	100 %

[1] Totals may not add due to rounding.

We had record production in the second 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 Financial Results and Trends Between the Three Months Ended June 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 $490.8 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 second quarter 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. The initial borrowing base under the credit facility was $1.9 billion. The borrowing base was subsequently reduced to $1.775 billion as a result of the issuance of the 2024 Notes. Please refer to the caption Credit Facility below and Note 5 - Long-term Debt in Part I, Item 1 of this report for additional discussion.

Equity Compensation. Subsequent to June 30, 2013, we granted 327,605 RSUs and 274,831 PSUs pursuant to our long-term equity incentive program. Also subsequent to June 30, 2013, we issued 522,850 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.

First Six Months of 2013 Highlights

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

	South Texas & Gulf Coast	Mid-Continent	Permian	Rocky Mountain	Total [1]
First six months of 2013 production:					
Oil (MMBbl)	2.3	0.2	0.8	3.0	6.4
Gas (Bcf)	45.8	21.5	1.6	2.6	71.4
NGLs (MMBbl)	4.0	0.1	—	—	4.1
Equivalent (MMBOE)	13.9	3.9	1.1	3.5	22.3
Avg. daily equivalents (MBOE/d)	76.7	21.7	6.0	19.1	123.4
Relative percentage	62 %	18 %	5 %	15 %	100 %

[1] Totals may not add due to rounding.

Please refer to Second Quarter 2013 Highlights and Outlook for the Remainder of 2013 above and Comparison of Financial Results and Trends Between the Six Months Ended June 30, 2013, and 2012 for additional discussion on production

Table of Contents

Costs Incurred in Oil and Gas Producing Activities. For the six months ended June 30, 2013, we incurred $842.2 million 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 Overview of Liquidity and Capital Resources below for additional discussion on how we expect to fund our capital program.

Impairment of Proved Properties. During the first six months of 2013, we recorded impairment of proved properties expense of $55.8 million. An impairment of $34.6 million related to our decision to no longer pursue the development of certain underperforming assets was recorded in the second quarter of 2013. Additionally, we recorded a $21.2 million impairment 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.

Financial Results of Operations and Additional Comparative Data

The table below provides information regarding selected production and financial information for the quarter ended June 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			
	June 30, 2013	March 31, 2013	December 31, 2012	September 30, 2012
	(in millions, except for production data)			
Production (MMBOE)	12.0	10.3	10.1	9.5
Oil, gas, and NGL production revenue	$534.5	$469.6	$424.7	$373.9
Lease operating expense	$56.2	$54.7	$48.0	$46.5
Transportation costs	$67.0	$47.4	$43.0	$37.0
Production taxes	$26.5	$23.5	$20.2	$18.9
DD&A	$225.7	$198.7	$204.3	$192.4
Exploration	$20.7	$15.4	$24.2	$25.4
General and administrative	$35.4	$32.3	$28.4	$32.2
Net income (loss)	$76.5	$16.7	$(67.1)	$(38.3)

Selected Performance Metrics:

	For the Three Months Ended			
	June 30, 2013	March 31, 2013	December 31, 2012	September 30, 2012
Average net daily production equivalent (MBOE per day)	131.8	115.0	109.9	103.3
Lease operating expense (per BOE)	$4.69	$5.28	$4.74	$4.89
Transportation costs (per BOE)	$5.59	$4.58	$4.25	$3.90
Production taxes as a percent of oil, gas, and NGL production revenue	5.0 %	5.0 %	4.8 %	5.1 %
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)	$18.82	$19.20	$20.20	$20.25
General and administrative (per BOE)	$2.95	$3.12	$2.81	$3.39

Note: Amounts may not recalculate due to rounding.

Table of Contents

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

	For the Three Months Ended June 30, 2013	2012	Amount Change Between Periods	Percent Change Between Periods	For the Six Months Ended June 30, 2013	2012	Amount Change Between Periods	Percent Change Between Periods
Net production volumes [(1)]								
Oil (MMBbl)	3.2	2.4	0.9	37 %	6.4	4.9	1.5	31 %
Gas (Bcf)	39.1	28.1	11.0	39 %	71.4	56.8	14.6	26 %
NGLs (MMBbl)	2.2	1.4	0.9	62 %	4.1	2.5	1.5	60 %
Equivalent (MMBOE)	12.0	8.4	3.6	42 %	22.3	16.9	5.5	32 %
Average net daily production [(1)]								
Oil (MBbl per day)	35.5	25.9	9.6	37 %	35.1	26.7	8.4	31 %
Gas (MMcf per day)	430.2	309.2	121.0	39 %	394.4	312.0	82.4	26 %
NGLs (MBbl per day)	24.6	15.2	9.4	62 %	22.5	14.0	8.6	61 %
Equivalent (MBOE per day)	131.8	92.6	39.2	42 %	123.4	92.7	30.7	33 %
Oil, gas, & NGL production revenue (in millions)								
Oil production revenue	$290.6	$194.7	$95.9	49 %	$577.7	$422.1	$155.6	37 %
Gas production revenue	167.6	65.7	101.9	155 %	282.6	148.9	133.7	90 %
NGL production revenue	76.3	52.2	24.1	46 %	143.8	104.2	39.6	38 %
Total	$534.5	$312.6	$221.9	71 %	$1,004.1	$675.2	$328.9	49 %
Oil, gas, & NGL production expense (in millions)								
Lease operating expense	$56.2	$46.1	$10.1	22 %	$110.9	$85.6	$25.3	30 %
Transportation costs	67.0	30.3	36.7	121 %	114.4	58.9	55.5	94 %
Production taxes	26.5	14.7	11.8	80 %	50.1	33.8	16.3	48 %
Total	$149.7	$91.1	$58.6	64 %	$275.4	$178.3	$97.1	54 %
Realized price								
Oil (per Bbl)	$90.00	$82.52	$7.48	9 %	$90.82	$86.72	$4.10	5 %
Gas (per Mcf)	$4.28	$2.34	$1.94	83 %	$3.96	$2.62	$1.34	51 %
NGLs (per Bbl)	$34.09	$37.79	$(3.70)	(10)%	$35.24	$40.94	$(5.70)	(14)%
Per BOE	$44.57	$37.09	$7.48	20 %	$44.95	$40.01	$4.94	12 %
Per BOE Data [(1)]								
Production costs:								
Lease operating expenses	$4.69	$5.48	$(0.79)	(14)%	$4.96	$5.07	$(0.11)	(2)%
Transportation costs	$5.59	$3.59	$2.00	56 %	$5.12	$3.49	$1.63	47 %
Production taxes	$2.21	$1.74	$0.47	27 %	$2.24	$2.00	$0.24	12 %
General and administrative	$2.95	$3.69	$(0.74)	(20)%	$3.03	$3.51	$(0.48)	(14)%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$18.82	$19.17	$(0.35)	(2)%	$19.00	$19.62	$(0.62)	(3)%
Derivative cash settlement [(2)]	$0.09	$1.97	$(1.88)	(95)%	$0.57	$1.41	$(0.84)	(60)%
Earnings per share information								
Basic net income per common share	$1.15	$0.39	$0.76	195 %	$1.41	$0.80	$0.61	76 %
Diluted net income per common share	$1.13	$0.37	$0.76	205 %	$1.38	$0.76	$0.62	82 %
	66,295	64,585	1,710	3 %	66,254	64,345	1,909	3 %

Basic weighted-average common shares outstanding (in thousands)								
Diluted weighted-average common shares outstanding (in thousands)	67,893	67,556	337	— %	67,711	67,806	(95)	— %

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

Table of Contents

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 reported production for the three and six months ended June 30, 2013, increased 42 percent and 33 percent, respectively, 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 six months ended June 30, 2013, increased 20 percent and 12 percent, respectively, compared to the same periods in 2012, due primarily to improved gas prices.

Lease operating expenses ("LOE") on a per BOE basis for the three and six months ended June 30, 2013, decreased 14 percent and two percent, respectively, 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. Based upon the current level of industry activity, we believe that LOE on a per BOE basis will remain relatively stable throughout the remainder of 2013.

Production taxes on a per BOE basis for the three and six months ended June 30, 2013, increased 27 percent and 12 percent, respectively, compared to the same periods in 2012, due to smaller incentive tax rebates on newer wells drilled in our South Texas & Gulf Coast region in 2013. Additionally, we recorded a sizable State of Oklahoma incentive tax rebate in the second quarter of 2012, which significantly decreased that quarter's per BOE rate. 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 six months ended June 30, 2013, increased 56 percent and 47 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 that we will recognize fluctuations in our per unit Eagle Ford transportation run-rate over time; however, we anticipate company-wide transportation costs will continue to increase on a per BOE basis as a function of our Eagle Ford shale program's continuing growth.

G&A expense on a per BOE basis for the three and six months ended June 30, 2013, decreased 20 percent and 14 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. We expect to continue to see an overall decrease in G&A on a per BOE basis for the remainder of 2013, as we anticipate production will continue to increase at a faster rate than our increase in G&A expense.

Depletion, depreciation, and amortization ("DD&A") expense on a per BOE basis for the three and six months ended June 30, 2013, decreased two percent and three 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 improved in part due to the utilization of our carry with Mitsui. As we continue to utilize our carry, we expect our DD&A rate to continue to improve, as we add reserves without incurring capital costs. Subsequent to June 30, 2013, we began the marketing of certain assets in our Mid-Continent region. We anticipate that these assets will be classified as held for sale throughout the third quarter of 2013. As a result, we expect our DD&A per BOE rate for the third quarter of 2013 to be impacted as these properties will no longer be depleted.

Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2013, and 2012 and Comparison of Financial Results and Trends Between the Six Months Ended June 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 per common share calculations.

Table of Contents

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

	Average Net Daily Production Added (Lost) (MBOE/d)	Oil, Gas, & NGL Revenue Added (in millions)	Production Costs Increase (in millions)
South Texas & Gulf Coast	39.9	$152.3	$45.3
Mid-Continent	(6.0)	12.5	2.0
Permian	1.8	16.9	4.7
Rocky Mountain	3.5	40.2	6.6
Total	39.2	$221.9	$58.6

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 for the next several years. 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 June 30, 2013, and 2012, despite a decrease in production volumes.

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

	For the Three Months Ended June 30,	
	2013	2012
Realized oil price ($/Bbl)	$90.00	$82.52
Realized gas price ($/Mcf)	$4.28	$2.34
Realized NGL price ($/Bbl)	$34.09	$37.79
Realized equivalent price ($/BOE)	$44.57	$37.09

A 42 percent increase in production on a BOE basis combined with a 20 percent increase in the realized price per BOE resulted in a 71 percent increase in revenue between the two periods. Based on current levels of activity, we expect production volumes to increase annually for the next several years. We also expect our realized prices to trend with commodity prices.

Realized hedge gain (loss). We recorded a net realized hedge loss of $1.2 million for the three months ended June 30, 2013, compared with a net realized hedge gain of $185,000 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. 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.

Gain (loss) on divestiture activity. We recorded a $6.3 million gain on divestiture activity for the three months ended June 30, 2013, as a result of the sale of properties in our Rocky Mountain region. We recorded a $24.2 million net loss for the same period in 2012, as a result of an unsuccessful divestiture of properties. We will continue to evaluate our portfolio to determine whether there are non-strategic properties that are candidates for divestiture.

Other operating revenues and expenses. These line items are comprised primarily of marketed gas system revenue and expense, both of which remained relatively flat for the three months ended June 30, 2013, as compared to the same period of 2012. There was no significant change in our net margin between these periods. 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 June 30, 2013, other operating expense included $14.2 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.

Table of Contents

Oil, gas, and NGL production expense. Total production costs increased 64 percent to $149.7 million for the three months ended June 30, 2013, compared with $91.1 million for the same period of 2012, as a result of a 42 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 six-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 40 percent to $225.7 million for the three-month period ended June 30, 2013, compared with $161.6 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 six-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 June 30,	
	2013	2012
	(in millions)	
Geological and geophysical expenses	$0.8	$1.5
Exploratory dry hole expense	5.7	7.6
Overhead and other expenses	14.2	12.9
Total	$20.7	$22.0

Exploration expense for the three months ended June 30, 2013, decreased six percent compared to the same period in 2012 due to higher exploratory dry hole expense recorded in the second quarter of 2012 relating to an unsuccessful exploratory well in our Rocky Mountain region, which was offset partially by an increase in exploration overhead in the second quarter of 2013 due to an increase in our exploration efforts. 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 $34.6 million impairment of proved properties expense for the three months ended June 30, 2013, related to our decision to no longer pursue the development of certain underperforming assets. We recorded a $38.5 million impairment in the second quarter of 2012 related to our Haynesville shale assets, which was caused by a decrease in natural gas prices. We expect impairments of proved properties to be more likely to occur in periods of low commodity prices, which negatively impact operating cash flows available for exploration and development, as well as anticipated economic performance.

Abandonment and impairment of unproved properties. We recorded abandonment and impairment expense of $4.3 million for the three months ended June 30, 2013, compared with $10.7 million for the same period of 2012, related to acreage we no longer intended to develop. We expect our abandonment and impairment of unproved properties to trend with any lease expirations. Unsuccessful exploratory activities may also result in impairments of unproved properties.

General and administrative. G&A expense increased 14 percent to $35.4 million for the three months ended June 30, 2013, compared with $31.1 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 six-month overview of selected production and financial information, including trends above for discussion of G&A expense on a per BOE basis.

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 June 30, 2013, we recorded a non-cash benefit of $5.4 million compared to a non-cash benefit of $22.1 million for the same period in 2012. The decrease in strip prices for oil, gas, and NGLs during the period from March 31, 2013, to June 30, 2013, was not as significant as the decrease in the comparable 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.

Table of Contents

Unrealized and realized derivative gain. We recognized an unrealized and realized derivative gain of $85.2 million for the three-month period ended June 30, 2013, compared to a gain of $98.1 million for the same period in 2012. Commodity strip prices decreased in both periods resulting in 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. We recorded income tax expense of $46.2 million for the three-month period ended June 30, 2013, compared to expense of $14.8 million for the same period in 2012, resulting in effective tax rates of 37.6 percent and 37.3 percent, respectively. The increase in income tax expense reflects the increase in net income before income tax expense between comparable periods. The 2013 increase in the effective rate from 2012 primarily reflects changes in the applicable mix of the highest marginal state tax rates, the effects of valuation allowance adjustments, and the state tax rate effect on year-to-date net income, offset by discreet adjustments from enacted state rate changes. 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 Six Months Ended June 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 six months ended June 30, 2013, and 2012:

	Average Net Daily Production Added (Lost) (MBOE/d)	Oil, Gas, & NGL Revenue Added (in millions)	Production Costs Increase (in millions)
South Texas & Gulf Coast	32.4	$244.3	$78.0
Mid-Continent	(5.4)	16.4	1.2
Permian	1.2	15.5	7.8
Rocky Mountain	2.5	52.7	10.1
Total	30.7	$328.9	$97.1

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

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

	For the Six Months Ended June 30, 2013	2012
Realized oil price ($/Bbl)	$90.82	$86.72
Realized gas price ($/Mcf)	$3.96	$2.62
Realized NGL price ($/Bbl)	$35.24	$40.94
Realized equivalent price ($/BOE)	$44.95	$40.01

A 32 percent increase in production on a BOE basis combined with a 12 percent increase in the realized price per BOE resulted in a 49 percent increase in revenue between the two periods.

Realized hedge gain (loss). We recorded a net realized hedge loss of $1.3 million for the six months ended June 30, 2013, compared with a net realized hedge gain of $1.8 million for the same period in 2012. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2013, and 2012 above for additional discussion.

Gain (loss) on divestiture activity. We recorded a $5.7 million gain on divestiture activity for the six months ended June 30, 2013, compared with a $22.7 million loss for the same period in 2012. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 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, both of which remained relatively flat for the six months ended June 30, 2013 as compared to the same period of 2012. There was no significant change in our net margin between these periods. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2013, and 2012 in the above section for additional discussion.

Table of Contents

Oil, gas, and NGL production expense. Total production costs increased 54 percent to $275.4 million for the six months ended June 30, 2013, compared with $178.3 million for the same period of 2012, as a result of a 32 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 six 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 28 percent to $424.4 million for the six-month period ended June 30, 2013, compared with $331.2 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 six-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 Six Months Ended June 30,	
	2013	2012
	(in millions)	
Geological and geophysical expenses	$2.3	$5.4
Exploratory dry hole expense	5.9	8.2
Overhead and other expenses	27.9	27.0
Total	$36.1	$40.6

Exploration expense for the six months ended June 30, 2013, decreased 11 percent compared to the same period in 2012 due to a decrease in geological and geophysical expenses as a result of a seismic study conducted in the first quarter of 2012 and higher exploratory dry hole expense recorded in 2012, partially offset by an increase in exploration overhead in 2013. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2013, and 2012 above for additional discussion.

Impairment of proved properties. We recorded impairment of proved properties expense of $55.8 million for the six months ended June 30, 2013, compared with $38.5 million for the same period in 2012. In addition to the discussion under Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2013, and 2012, we recorded a $21.2 million impairment 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.

Abandonment and impairment of unproved properties. We recorded abandonment and impairment expense of $4.6 million for the six months ended June 30, 2013, compared with $10.8 million for the same period of 2012. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2013, and 2012 above for additional discussion.

General and administrative. G&A expense increased 14 percent to $67.7 million for the six months ended June 30, 2013, compared with $59.3 million for the same period of 2012. Please refer to the captions Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2013, and 2012 and A three-month and six-month overview of selected production and financial information, including trends above for additional discussion.

Change in Net Profits Plan liability. For the six months ended June 30, 2013, we recorded a non-cash benefit of $7.4 million compared to a non-cash benefit of $18.1 million for the same period in 2012. Please refer to the caption Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2013, and 2012 above for additional discussion.

Unrealized and realized derivative gain. We recognized an unrealized and realized derivative gain of $54.6 million for the six-month period ended June 30, 2013, compared to a gain of $95.9 million for the same period in 2012. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2013, and 2012 above for additional discussion.

Income tax expense. We recorded income tax expense of $56.6 million for the six-month period ended June 30, 2013, compared to expense of $30.5 million for the same period in 2012, resulting in effective tax rates of 37.8 percent and 37.3 percent, respectively. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2013, and 2012 above for additional discussion.

Table of Contents

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 us with 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. 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 $432.7 million had been spent as of June 30, 2013. The remaining carry is expected to be used throughout 2013 and into 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. This amended credit facility 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 $1.775 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. 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 June 30, 2013, and July 25, 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 June 30, 2013, our debt to EBITDAX ratio and adjusted current ratio were 1.3 and 2.8, 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 approximately $253.5 million and $236.4 million for the three months ended June 30, 2013, and 2012, respectively. Our daily weighted-average credit facility balance was $323.8 million, and $118.5

million for the six months ended June 30, 2013, and 2012, respectively. The increases in the respective periods are due to capital spending, as well as the timing of our application of proceeds from our 2021 Notes in late 2011 compared to the timing of our application of proceeds from our 2024 Notes during the second quarter of 2013. Borrowings under our credit facility are secured by mortgages on the majority of our oil and gas properties.

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 six months ended June 30, 2013, and 2012:

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
	2013		2012		2013		2012	
Weighted-average interest rate	6.2	%	5.5	%	6.0	%	6.5	%
Weighted-average borrowing rate	5.6	%	4.9	%	5.5	%	5.3	%

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.

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 six months of 2013, we spent $793.2 million 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 six-month periods ended June 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 Six Months Ended June 30,		Amount Change Between Periods	Percent Change Between Periods
	2013	2012		
	(in millions)			
Net cash provided by operating activities	$596.4	$410.3	$186.1	45 %
Net cash (used in) investing activities	$(777.8)	$(695.2)	$(82.6)	12 %
Net cash provided by financing activities	$175.7	$165.9	$9.8	6 %

Analysis of Cash Flow Changes Between the Six Months Ended June 30, 2013, and 2012

Operating activities. Cash received from oil, gas, and NGL production revenues, including derivative cash settlements, increased $253.2 million, or 35 percent, to $980.6 million for the first six 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 $18.1 million to $111.9 million for the first six 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 six months of 2013 increased $6.0 million compared to the same period in 2012, due to interest paid on our 2023 Notes in the first quarter 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 in 2013, including acquisition of proved and unproved oil and gas properties, increased $82.5 million, or 12 percent, compared with the same period in 2012. This increase was due to increased drilling activity, driven primarily by successful development and delineation activities in our Eagle Ford shale, Bakken/Three Forks, and Permian programs, and a completed acquisition of proved and unproved properties in our Rocky Mountain region in the second quarter of 2013.

Financing activities. We received $490.8 million of net proceeds from the issuance of our 2024 Notes in the second quarter of 2013, compared with $392.3 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 six months ended June 30, 2013, compared with net borrowings of $61.0 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.

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 June 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 June 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.

Table of Contents

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.

Table of Contents

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, unrealized derivative gains and losses, 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 June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
	(in thousands)			
Net income (GAAP)	$76,522	$24,889	$93,249	$51,225
Interest expense	21,581	12,712	40,682	26,990
Interest income	(24)	(5)	(36)	(75)
Income tax expense	46,205	14,795	56,587	30,476
Depreciation, depletion, amortization, and asset retirement obligation liability accretion	225,731	161,608	424,440	331,178
Exploration [(1)]	18,383	22,007	31,607	40,614
Impairment of proved properties	34,552	38,523	55,771	38,523
Abandonment and impairment of unproved properties	4,339	10,707	4,641	10,849
Stock-based compensation expense	9,955	8,022	18,068	12,372
Unrealized derivative gain	(82,979)	(81,666)	(40,615)	(74,014)
Change in Net Profits Plan liability	(5,438)	(22,079)	(7,363)	(18,140)
(Gain) loss on divestiture activity	(6,280)	24,176	(5,706)	22,714
EBITDAX (Non-GAAP)	342,547	213,689	671,325	472,712
Interest expense	(21,581)	(12,712)	(40,682)	(26,990)
Interest income	24	5	36	75
Income tax expense	(46,205)	(14,795)	(56,587)	(30,476)
Exploration	(18,383)	(22,007)	(31,607)	(40,614)
Exploratory dry hole expense	5,727	7,592	5,886	8,198
Amortization of debt discount and deferred financing costs	1,363	951	2,440	4,616
Deferred income taxes	45,959	14,927	56,239	30,215
Plugging and abandonment	(2,368)	(670)	(3,746)	(1,516)
Other	3,933	(595)	5,769	(867)
Changes in current assets and liabilities	3,047	35,850	(12,718)	(5,065)
Net cash provided by operating activities (GAAP)	$314,063	$222,235	$596,355	$410,288

[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.

Table of Contents

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;

Table of Contents

- 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 vendors, 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 second 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.

Table of Contents

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

(c) The following table provides information about purchases by the Company or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the fiscal quarter ended June 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

	(a)	(b)	(c)	(d)
Period	Total Number of Shares Purchased [1]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Number of Shares that May Yet Be Purchased Under the Program [2]
04/01/13 - 04/30/13	390	$58.48	—	3,072,184
05/01/13 - 05/31/13	—	$—	—	3,072,184
06/01/13 - 06/30/13	—	$—	—	3,072,184
Total:	390	$58.48	—	3,072,184

(1) All shares purchased in the second quarter of 2013 were to offset tax withholding obligations that occur upon the delivery of outstanding shares underlying RSUs 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.

Table of Contents

ITEM 6. EXHIBITS

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

Exhibit	Description
4.1	Indenture related to the 5.0% Senior Notes due 2024, dated May 20, 2013, by and between SM Energy Company, as issuer, and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on May 20, 2013, and incorporated herein by reference)
4.2	Registration Rights Agreement, dated May 20, 2013, by and among SM Energy Company and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Wells Fargo Securities, LLC, and J.P. Morgan Securities LLC, as representatives of several purchasers (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on May 20, 2013, and incorporated herein by reference)
10.1	Fifth Amended and Restated Credit Agreement dated April 12, 2013, among SM Energy Company, as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on April 15, 2013, and incorporated herein by reference)
10.2*	Form of Performance Stock Unit Award Agreement
10.3*	Form of Restricted Stock Unit Award Agreement
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

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* Filed with this report.

** Furnished with this report.

Table of Contents

SIGNATURES

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

	SM ENERGY COMPANY
July 31, 2013	By: /s/ ANTHONY J. BEST Anthony J. Best Chief Executive Officer (Principal Executive Officer)
July 31, 2013	By: /s/ A. WADE PURSELL A. Wade Pursell Executive Vice President and Chief Financial Officer (Principal Financial Officer)
July 31, 2013	By: /s/ MARK T. SOLOMON Mark T. Solomon Vice President - Controller and Assistant Secretary (Principal Accounting Officer)