SM Energy Co
Form 10-Q
July 29, 2015

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, 2015
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 22, 2015, the registrant had 67,950,361 shares of common stock, $0.01 par value, outstanding.

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

	June 30, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$82	$120
Accounts receivable	239,983	322,630
Derivative asset	269,022	402,668
Prepaid expenses and other	16,621	19,625
Total current assets	525,708	745,043
Property and equipment (successful efforts method):		
Proved oil and gas properties	7,356,877	7,348,436
Less - accumulated depletion, depreciation, and amortization	(3,073,603)	(3,233,012)
Unproved oil and gas properties	419,903	532,498
Wells in progress	419,979	503,734
Oil and gas properties held for sale net of accumulated depletion, depreciation and amortization of $30,514 and $22,482, respectively	7,361	17,891
Other property and equipment, net of accumulated depreciation of $38,051 and $37,079, respectively	354,528	334,356
Total property and equipment, net	5,485,045	5,503,903
Noncurrent assets:		
Derivative asset	131,464	189,540
Other noncurrent assets	71,401	78,214
Total other noncurrent assets	202,865	267,754
Total Assets	$6,213,618	$6,516,700
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$423,536	$640,684
Derivative liability	8,107	—
Deferred tax liability	90,514	142,976
Other current liabilities	—	1,000
Total current liabilities	522,157	784,660
Noncurrent liabilities:		
Revolving credit facility	122,000	166,000
Senior Notes (note 5)	2,350,000	2,200,000
Asset retirement obligation	115,276	120,867
Net Profits Plan liability	18,326	27,136
Deferred income taxes	859,588	891,681
Derivative liability	1,026	70
Other noncurrent liabilities	36,938	39,631
Total noncurrent liabilities	3,503,154	3,445,385

Commitments and contingencies (note 6)		
Stockholders' equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued and outstanding: 67,598,649 and 67,463,060, respectively	676	675
Additional paid-in capital	299,637	283,295
Retained earnings	1,900,058	2,013,997
Accumulated other comprehensive loss	(12,064)	(11,312)
Total stockholders' equity	2,188,307	2,286,655
Total Liabilities and Stockholders' Equity	$6,213,618	$6,516,700

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

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Operating revenues:				
Oil, gas, and NGL production revenue	$441,256	$654,661	$834,571	$1,277,770
Net gain on divestiture activity (note 3)	71,884	2,526	36,082	5,484
Other operating revenues	3,006	17,793	11,427	24,446
Total operating revenues and other income	516,146	674,980	882,080	1,307,700
Operating expenses:				
Oil, gas, and NGL production expense	173,685	177,598	369,836	341,307
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	219,704	187,781	437,105	364,996
Exploration	25,541	24,270	62,948	45,605
Impairment of proved properties	12,914	—	68,440	—
Abandonment and impairment of unproved properties	5,819	164	17,446	2,965
General and administrative	42,605	38,115	86,244	73,166
Change in Net Profits Plan liability	(4,476)	(7,105)	(8,810)	(8,881)
Derivative (gain) loss	80,929	126,469	(73,238)	224,131
Other operating expenses	10,304	5,972	27,423	14,061
Total operating expenses	567,025	553,264	987,394	1,057,350
Income (loss) from operations	(50,879)	121,716	(105,314)	250,350
Non-operating income (expense):				
Other, net	25	(1,847)	596	(1,821)
Interest expense	(30,779)	(24,040)	(63,426)	(48,230)
Loss on extinguishment of debt	(16,578)	—	(16,578)	—
Income (loss) before income taxes	(98,211)	95,829	(184,722)	200,299
Income tax (expense) benefit	40,703	(36,049)	74,156	(74,912)
Net income (loss)	$(57,508)	$59,780	$(110,566)	$125,387
Basic weighted-average common shares outstanding	67,483	67,069	67,473	67,063
Diluted weighted-average common shares outstanding	67,483	68,239	67,473	68,180
Basic net income (loss) per common share	$(0.85)	$0.89	$(1.64)	$1.87
Diluted net income (loss) per common share	$(0.85)	$0.88	$(1.64)	$1.84
Dividends per common share	$—	$—	$0.05	$0.05

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

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Net income (loss)	$(57,508)	$59,780	$(110,566)	$125,387
Other comprehensive income (loss), net of tax:				
Pension liability adjustment	(576)	330	(752)	330
Total other comprehensive income (loss), net of tax	(576)	330	(752)	330
Total comprehensive income (loss)	$(58,084)	$60,110	$(111,318)	$125,717

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

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

	For the Six Months Ended June 30,	
	2015	2014
Cash flows from operating activities:		
Net income (loss)	$(110,566)	$125,387
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Net gain on divestiture activity	(36,082)	(5,484)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	437,105	364,996
Exploratory dry hole expense	22,896	6,459
Impairment of proved properties	68,440	—
Abandonment and impairment of unproved properties	17,446	2,965
Stock-based compensation expense	13,215	14,341
Change in Net Profits Plan liability	(8,810)	(8,881)
Derivative (gain) loss	(73,238)	224,131
Derivative cash settlements	291,619	(62,620)
Amortization of deferred financing costs	3,892	2,954
Non-cash loss on extinguishment of debt	4,123	—
Deferred income taxes	(84,556)	73,911
Plugging and abandonment	(3,386)	(3,219)
Other, net	(434)	(4,827)
Changes in current assets and liabilities:		
Accounts receivable	38,951	(2,558)
Prepaid expenses and other	2,933	1,302
Accounts payable and accrued expenses	(34,040)	(13,704)
Net cash provided by operating activities	549,508	715,153
Cash flows from investing activities:		
Net proceeds from sale of oil and gas properties	334,988	46,821
Capital expenditures	(974,130)	(778,580)
Acquisition of proved and unproved oil and gas properties	(6,588)	(98,619)
Other, net	(996)	(2,257)
Net cash used in investing activities	(646,726)	(832,635)
Cash flows from financing activities:		
Proceeds from credit facility	1,230,500	—
Repayment of credit facility	(1,274,500)	—
Net proceeds from Senior Notes	491,557	—
Repayment of Senior Notes	(350,000)	—
Proceeds from sale of common stock	3,157	2,490
Dividends paid	(3,373)	(3,353)
Other, net	(161)	(109)
Net cash provided by (used in) financing activities	97,180	(972)
Net change in cash and cash equivalents	(38)	(118,454)
Cash and cash equivalents at beginning of period	120	282,248
Cash and cash equivalents at end of period	$82	$163,794

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

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

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

	For the Six Months Ended June 30,	
	2015	2014
	(in thousands)	
Cash paid for interest, net of capitalized interest	$64,899	$47,403
Net cash paid for income taxes	$380	$162

As of June 30, 2015, and 2014, $164.9 million and $328.6 million, respectively, of accrued capital expenditures were included in accounts payable and accrued expenses in the Company's condensed consolidated balance sheets. These oil and gas property additions are reflected in cash used in investing activities in the periods during which the payables are settled.

During the second quarter of 2014, the Company exchanged properties in its Rocky Mountain region for other properties also located in its Rocky Mountain region with a fair value of $6.2 million. The amount of cash consideration paid at closing for agreed upon adjustments is reflected in the acquisition of proved and unproved oil and gas properties line item in the condensed consolidated statements of cash flows.

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.

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, 2014 (the "2014 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, 2015, through the filing date of this report. Certain prior period amounts have been reclassified to conform to the current presentation on the accompanying financial statements.

Significant Accounting Policies

The significant accounting policies followed by the Company are set forth in Note 1 to the Company's consolidated financial statements in its 2014 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 2014 Form 10-K.

Recently Issued Accounting Standards

Effective January 1, 2015, the Company early adopted, on a prospective basis, Financial Accounting Standards Board ("FASB") Accounting Standards Update ("ASU") No. 2015-01, "Income Statement – Extraordinary and Unusual Items." This ASU simplifies income statement presentation by eliminating the concept of extraordinary items. There was no impact to the Company's financial statements or disclosures from the adoption of this standard.

In April 2015, the FASB issued new authoritative accounting guidance requiring debt issuance costs to be presented on the balance sheet as a direct deduction from the carrying value of the related debt liability. This guidance is to be applied using a retrospective method and is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2015. Early application is permitted. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company's financial statements and disclosures.

There are no other new significant accounting standards applicable to the Company that have been issued but not yet adopted by the Company as of June 30, 2015, and through the filing date of this report that have not been disclosed above or in the 2014 Form 10-K.

Note 3 – Acquisitions, Divestitures, and Assets Held for Sale
Divestitures

During the second quarter of 2015, the Company divested its Mid-Continent assets in separate packages for total cash proceeds received at closing, which reflects gross purchase price net of closing adjustments (referred to throughout this report as “divestiture proceeds”), of $316.5 million and an estimated total net gain of $107.8 million. These assets were classified as held for sale as of March 31, 2015, and certain of these assets were written down by $30.0 million during the three months ended March 31, 2015, to reflect fair value less estimated costs to sell. This write-down is reflected in the total net gain of $107.8 million discussed above. These divestitures are subject to normal post-closing adjustments.

In conjunction with the Company's efforts to divest its Mid-Continent assets, the Company had previously announced the planned closure of its Tulsa, Oklahoma office in 2015, with the relocation of certain personnel to other Company offices. The Company expects to incur a total of approximately $10 million of exit and disposal costs associated with the severance, retention and relocation of employees, and other related matters, excluding the lease expenses discussed in the next paragraph. The majority of these exit and disposal activities are expected to be completed by the end of the third quarter of 2015. For the three and six months ended June 30, 2015, the Company recorded $5.0 million and $8.5 million, respectively, of exit and disposal costs, the majority of which were recorded as general and administrative expense in the accompanying condensed consolidated statements of operations ("accompanying statements of operations").

Additionally, subsequent to June 30, 2015, the Company vacated its office space in Tulsa and is currently attempting to sublease the remaining space. As of June 30, 2015, the Company is obligated to pay approximately $7 million, net of expected income from office space currently subleased, which will be expensed over the duration of the lease, which expires in 2022. This obligation will decrease if the Company successfully executes additional sublease agreements.

Assets Held for Sale

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

As of June 30, 2015, the accompanying condensed consolidated balance sheets ("accompanying balance sheets") present $7.4 million of assets held for sale, net of accumulated depletion, depreciation, and amortization expense, which primarily consists of certain assets in exploratory areas that the Company no longer intends to explore and develop in light of the low commodity price environment. There is a corresponding asset retirement obligation liability of approximately $200,000 for assets held for sale recorded in the asset retirement obligation liability financial statement line item in the accompanying balance sheets. For the three months ended June 30, 2015, the Company recorded write-downs to fair value less estimated costs to sell of $66.0 million for certain of these assets held for sale. For the six months ended June 30, 2015, write-downs on certain assets held for sale totaled $99.9 million, which included the $30.0 million write-down recorded on certain Mid-Continent assets in the first quarter 2015 as discussed above. These write-downs are recorded in the net gain on divestiture activity line item in the accompanying statements of operations.

The Company determined that neither these planned nor executed asset sales qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

Note 4 - Income Taxes

Income tax expense (benefit) for the three and six months ended June 30, 2015, and 2014, differs from the amount that would be provided by applying the statutory United States federal income tax rate to income before income taxes primarily due to the effect of state income taxes, changes in valuation allowances, percentage depletion, research and development ("R&D") credits, and other permanent differences. The quarterly rate can also be impacted by the proportional effects of forecasted net income or loss as of each period end presented.

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The provision for income taxes consists of the following:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)			
Current portion of income tax expense:				
Federal	$—	$—	$—	$—
State	10,126	512	10,400	1,001
Deferred portion of income tax expense (benefit)	(50,829)	35,537	(84,556)	73,911
Total income tax expense (benefit)	$(40,703)	$36,049	$(74,156)	$74,912
	41.4 %	37.6 %	40.1 %	37.4 %

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. As a result of divestitures during the second quarter of 2015, the Company no longer has oil and gas operations in Oklahoma or Louisiana and recorded current state income tax expense related to the sold properties. Cumulative effects of state rate changes are reflected in the period legislation is enacted. The cumulative effects of Texas and North Dakota enacted rate changes are reflected above in the deferred portion of income tax expense (benefit).

The Company is generally no longer subject to United States federal or state income tax examinations by tax authorities for years before 2007. During the first quarter of 2015, as a result of its R&D credit settlement with the IRS Appeals Office in late 2014, the Company recorded an additional $2.0 million net R&D credit from a claim filed on an amended return. No R&D credit was recorded in 2014.

Note 5 - Long-term Debt

Revolving Credit Facility

The Company's Fifth Amended and Restated Credit Agreement, as amended (the "Credit Agreement"), provides a maximum loan amount of $2.5 billion, current aggregate lender commitments of $1.5 billion, and a maturity date of December 10, 2019. In April 2015, the lenders maintained the borrowing base at $2.4 billion as part of the regularly scheduled semi-annual redetermination under the Credit Agreement. In the Third Amendment to the Credit Agreement dated May 20, 2015, the lenders agreed not to reduce the $2.4 billion borrowing base as a result of the issuance of the Company's 5.625% Senior Notes due 2025 and the Mid-Continent divestitures. The next redetermination date is scheduled for October 1, 2015. Borrowings under the facility are secured by mortgages on assets having a value equal to at least 75 percent of the total value of the Company's proved oil and gas properties.

The Company must comply with certain financial and non-financial covenants under the terms of the Credit Agreement, including limitations on the payment of dividends to $50.0 million per year. The Company was in compliance with all covenants under the Credit Agreement as of June 30, 2015, and through the filing date of this report.

The following table presents the outstanding balance, total amount of letters of credit, and available borrowing capacity under the Credit Agreement as of July 22, 2015, June 30, 2015, and December 31, 2014:

	As of July 22, 2015	As of June 30, 2015	As of December 31, 2014
	(in thousands)		
Credit facility balance	$175,000	$122,000	$166,000

Letters of credit [1]	$200	$200	$808
Available borrowing capacity	$1,324,800	$1,377,800	$1,333,192

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

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Senior Notes

The Senior Notes line on the accompanying balance sheets represents the outstanding principal amount of the notes shown in the table below (the "Senior Notes"):

	As of June 30, 2015	As of December 31, 2014
	(in thousands)	
6.625% Senior Notes due 2019	$—	$350,000
6.50% Senior Notes due 2021	350,000	350,000
6.125% Senior Notes due 2022	600,000	600,000
6.50% Senior Notes due 2023	400,000	400,000
5.0% Senior Notes due 2024	500,000	500,000
5.625% Senior Notes due 2025	500,000	—
Total Senior Notes	$2,350,000	$2,200,000

The Senior Notes are unsecured senior obligations and rank equal in right of payment with all of the Company's existing and any future unsecured senior debt, and are senior in right of payment to any future subordinated debt. There are no subsidiary guarantors of the Senior Notes. The Company is subject to certain covenants under the respective indentures governing the Senior Notes that limit the Company's ability to incur additional indebtedness, issue preferred stock, and make restricted payments, including dividends; provided, however, that the first $6.5 million of dividends paid each year are not restricted by this restricted payment covenant. The Company was in compliance with all covenants under its Senior Notes as of June 30, 2015, and through the filing date of this report.

2019 Notes

On May 7, 2015, the Company commenced a cash tender offer for any and all of its outstanding 6.625% Senior Notes due 2019 (the "2019 Notes") at a price of $1,036.88 per $1,000 of principal amount for all 2019 Notes tendered by May 20, 2015 ("Consent Payment Deadline"), and at a price of $1,006.88 per $1,000 of principal amount for all 2019 Notes properly tendered thereafter. On the Consent Payment Deadline, the Company received tenders and consents from the holders of approximately $242.9 million in aggregate principal amount, or approximately 69%, of its outstanding 2019 Notes in connection with the cash tender offer. Following its entry into the supplemental indenture dated as of May 21, 2015, to the indenture dated as of February 7, 2011, between the Company and U.S. Bank National Association, as Trustee, the Company accepted the 2019 Notes tendered as of the Consent Payment Deadline in exchange for payment of total consideration, including accrued interest, of approximately $256.2 million under the Tender Offer and Consent Solicitation. On June 5, 2015, the Company accepted $1.5 million of 2019 Notes tendered after the Consent Payment Deadline in exchange for payment of total consideration, including accrued interest, of approximately $1.6 million.

On June 22, 2015, the Company redeemed the remaining outstanding 2019 Notes at a redemption price of 103.313% of the principal amount for payment of total consideration, including accrued interest, of approximately $111.5 million.

The Company recorded a loss on extinguishment of debt related to the tender offer and redemption of its 2019 Notes of approximately $16.6 million for the quarter ended June 30, 2015. This amount includes approximately $12.5 million associated with the premium paid for the tender offer and redemption of the 2019 Notes and approximately $4.1 million related to the acceleration of unamortized deferred financing costs.

2025 Notes

On May 21, 2015, the Company issued and sold $500.0 million in aggregate principal amount of 5.625% Senior Notes due 2025 (the "2025 Notes") to certain underwriters in a public offering registered under the Securities Act of 1933, as amended (the "Securities Act"). The 2025 Notes were issued at par and mature on June 1, 2025. The Company received net proceeds of approximately $491.1 million after deducting paid and accrued fees of $8.9 million, which are being amortized as deferred financing costs over the life of the 2025 Notes. The net proceeds were used to fund the consideration paid to the tendering holders of the 2019 Notes and to redeem the remaining un-tendered 2019 Notes, as well as repay outstanding borrowings under the Credit Agreement and for general corporate purposes.

Prior to June 1, 2018, the Company may redeem, on one or more occasions, up to 35 percent of the aggregate principal amount of the 2025 Notes with the net cash proceeds of certain equity offerings at a redemption price of 105.625% of the principal amount thereof, plus accrued and unpaid interest. The Company may also redeem the 2025 Notes, in whole or in part, at any time prior to June 1, 2020, at a redemption price equal to 100 percent of the principal amount of the 2025 Notes to be redeemed, plus a specified make-whole premium and accrued and unpaid interest to the applicable redemption date.

On or after June 1, 2020, the Company may also redeem all or, from time to time during the twelve-month period beginning on June 1 of each applicable year, a portion of the 2025 Notes at the redemption prices set forth below expressed as a percentage of the principal amount redeemed, plus accrued and unpaid interest:

2020	102.813	%
2021	101.875	%
2022	100.938	%
2023 and thereafter	100.000	%

2022 Notes

The Company completed its offer to exchange its 6.125% Senior Notes due 2022 for notes registered under the Securities Exchange Act of 1934 (the “Exchange Act”) on July 10, 2015.

Note 6 - Commitments and Contingencies

Commitments

There were no material changes in commitments during the first half of 2015. Please refer to Note 6 - Commitments and Contingencies in the Company’s 2014 Form 10-K for additional discussion.

In light of the low commodity price environment, the Company curtailed drilling activity during the first half of 2015. For the three and six months ended June 30, 2015, the Company incurred drilling rig termination fees of $2.7 million and $5.9 million, respectively, which are recorded in the other operating expenses line item in the accompanying statements of operations.

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 expected results of any 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.

The Company is subject to routine severance, royalty and joint interest audits from regulatory authorities, non-operators and others, as the case may be, and records accruals for estimated exposure when a claim is deemed probable and estimable. Additionally, the Company is subject to various possible contingencies that arise from third party interpretations of the Company’s contracts or otherwise affecting the oil and natural gas industry. Such contingencies include differing interpretations as to the prices at which oil and natural gas sales may be made, the prices that royalty owners are paid for production from their leases, allowable costs under joint interest arrangements, and other matters. At June 30, 2015, the Company had $4.7 million accrued for estimated exposure related to claims for payment of royalties on certain Federal and Indian leases. Although the Company believes that it has properly estimated its exposure with respect to the various contracts, laws and regulations, administrative rulings, and interpretations thereof, adjustments could be required as new interpretations and regulations arise.

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Note 7 - Compensation Plans

Performance Share Units Under the Equity Incentive Compensation Plan

The Company grants performance share units (“PSUs”) to eligible employees as a part of its equity compensation program. The number of shares of the Company’s common stock issued to settle PSUs ranges from 0% to 200% of the number of PSUs awarded and is determined based on certain performance criteria 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 performance period and the relative performance of the Company’s TSR compared with the annualized TSR of certain peer companies for the performance period. PSUs are recognized as general and administrative and exploration expense over the vesting periods of the award.

Total expense recorded for PSUs for the three months ended June 30, 2015, and 2014, was $2.7 million and $3.6 million, respectively, and $5.0 million and $6.8 million for the six months ended June 30, 2015, and 2014, respectively. As of June 30, 2015, there was $13.0 million of total unrecognized compensation expense related to unvested PSU awards, which is being amortized through 2017. There were no material changes to the outstanding and non-vested PSUs during the six months ended June 30, 2015.

Subsequent to June 30, 2015, the Company granted 320,753 PSUs with a fair value of $14.5 million 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, 2015, the Company settled PSUs that were granted in 2012, which earned a 1.0 times multiplier, by issuing a net 188,279 shares of the Company’s common stock in accordance with the terms of the respective PSU awards. The Company and the majority of grant participants mutually agreed to net share settle a portion of the awards to cover income and payroll tax withholdings as provided for in the plan document and award agreements. As a result, 100,683 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon delivery of the shares underlying those PSUs.

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 for one share of the Company’s common stock to be delivered upon settlement of the award at the end of the specified vesting period. RSUs are recognized as general and administrative expense and exploration expense over the vesting periods of the award.

Total expense recorded for RSUs was $2.9 million for each of the three months ended June 30, 2015, and 2014, and $5.8 million and $5.7 million for the six months ended June 30, 2015, and 2014, respectively. As of June 30, 2015, there was $14.3 million of total unrecognized compensation expense related to unvested RSU awards, which is being amortized through 2017. There were no material changes to the outstanding and non-vested RSUs during the six months ended June 30, 2015.

Subsequent to June 30, 2015, the Company granted 356,246 RSUs with a fair value of $15.6 million 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, 2015, the Company settled 236,342 RSUs that related to awards granted in previous years. The Company and the majority of grant participants mutually agreed to net share settle a portion of 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 163,433 net shares of common stock. The remaining 72,909 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon delivery of the shares underlying those RSUs.

Director Shares

During the first half of 2015 and 2014, the Company issued 37,950 and 23,009 shares, respectively, of its common stock to its non-employee directors, under the Company's Equity Incentive Compensation Plan. The Company recorded approximately $1.2 million of compensation expense related to these awards for the three and six months ended June 30, 2015, and 2014.

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, unless five years of service has been provided by the director, in which case that director's shares vest upon the earlier of the completion of the one-year service period or the director retiring from the Board of Directors.

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% 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 ("IRC"). The Company had 1.1 million shares available for issuance under the ESPP as of June 30, 2015. There were 96,285 and 35,249 shares issued under the ESPP during the second quarters of 2015 and 2014, respectively. The fair value of ESPP grants is measured at the date of grant using the Black-Scholes option-pricing model.

Net Profits Plan

Cash payments made or accrued under the Company's Net Profits Plan totaled $1.9 million and $2.2 million for the three months ended June 30, 2015, and 2014, respectively, and $3.2 million and $5.4 million for the six months ended June 30, 2015, and 2014, respectively, the majority of which were recorded as general and administrative expense within the accompanying statements of operations.

Additionally, the Company accrued or made cash payments under the Net Profits Plan of $3.8 million for the three-month and six-month periods ended June 30, 2015, and $8.5 million for the three-month and six-month periods ended June 30, 2014, as a result of the divestitures of properties subject to the Net Profits Plan. These cash payments are accounted for as a reduction in the net gain on divestiture activity line item in the accompanying statements of operations.

The Company records changes in the present value of estimated future payments under the Net Profits Plan as a separate line item in the accompanying statements of operations. The change in the estimated liability is recorded as a non-cash expense or benefit in the current period. The amount recorded as an expense or benefit associated with the change in the estimated liability is not allocated to general and administrative expense or exploration expense because it is associated with the future net cash flows from oil and gas properties in the respective pools rather than results being realized through current period production. If the Company allocated the change in liability to these specific functional line items, based on the current allocation of actual distributions made by the Company, such expenses or benefits would predominately be allocated to general and administrative expense. As time has passed, the amount distributed relating to prospective exploration efforts has become insignificant as more 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,	
	2015	2014	2015	2014
	(in thousands)			
Service cost	$2,390	$1,595	$3,974	$3,168
Interest cost	700	688	1,248	1,095
Expected return on plan assets that reduces periodic pension costs	(597)	(604)	(1,091)	(989)
Amortization of prior service costs	5	5	9	9
Amortization of net actuarial loss	571	38	743	344
Net periodic benefit cost	$3,069	$1,722	$4,883	$3,627

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

The Company contributed $5.6 million to the Pension Plans during the six month period ended June 30, 2015.

Note 9 - Earnings Per Share

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

Diluted net income or loss per common share is calculated by dividing adjusted net income or loss by the diluted weighted-average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist of unvested RSUs, contingent PSUs, and in-the-money outstanding stock options. The treasury stock method is used to measure the dilutive impact of these stock awards. All remaining stock options were exercised during the year ended December 31, 2014, and therefore, were only dilutive for the three and six months ended June 30, 2014. When there is a loss from continuing operations, as was the case for the three and six months ended June 30, 2015, all potentially dilutive shares are anti-dilutive and are consequently excluded from the calculation of diluted net loss per common share. For the three and six months ended June 30, 2015, weighted-average anti-dilutive securities related to unvested RSUs and contingent PSUs totaled approximately 590,000 and 490,000 shares, respectively.

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 0% to 200% of 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 Share Units Under the Equity Incentive Compensation Plan.

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,		
	2015		2014	2015		2014
	(in thousands, except per share amounts)					
Net income (loss)	$(57,508	)	$59,780	$(110,566	)	$125,387
Basic weighted-average common shares outstanding	67,483		67,069	67,473		67,063
Add: dilutive effect of stock options, unvested RSUs, and contingent PSUs	—		1,170	—		1,117
Diluted weighted-average common shares outstanding	67,483		68,239	67,473		68,180
Basic net income (loss) per common share	$(0.85	)	$0.89	$(1.64	)	$1.87
Diluted net income (loss) per common share	$(0.85	)	$0.88	$(1.64	)	$1.84

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 collar arrangements for oil, gas, and NGLs.

As of June 30, 2015, the Company had commodity derivative contracts outstanding through the second quarter of 2020 for a total of 9.7 million Bbls of oil production, 167.0 million MMBtu of gas production, and 9.5 million Bbls of NGL production.

In a typical commodity swap agreement, if the agreed upon published third-party index price ("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 index price and the floor price if the index price is below the floor price. The Company pays the difference between the 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, 2015:

Oil Contracts

Oil Swaps

Contract Period	NYMEX WTI Volumes	Weighted-Average Contract Price
	(Bbls)	(per Bbl)
Third quarter 2015	1,254,000	$90.78
Fourth quarter 2015	1,137,000	$90.15
2016	5,570,000	$88.01
All oil swaps	7,961,000	

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(Bbls)	(per Bbl)	(per Bbl)
Third quarter 2015	906,000	$85.00	$91.25
Fourth quarter 2015	869,000	$85.00	$92.19
All oil collars	1,775,000		

Gas Contracts

Gas Swaps

Contract Period	Volumes	Weighted-Average Contract Price
	(MMBtu)	(per MMBtu)
Third quarter 2015	12,835,000	$4.03
Fourth quarter 2015	12,499,000	$4.01
2016	45,172,000	$4.13
2017	34,335,000	$4.19
2018	30,606,000	$4.27
2019	24,415,000	$4.34
All gas swaps*	159,862,000	

*Gas swaps are comprised of IF El Paso Permian (3%), IF HSC (93%), IF NGPL TXOK (1%), and IF NNG Ventura (3%).

Gas Collars

Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(MMBtu)	(per MMBtu)	(per MMBtu)
Third quarter 2015	2,005,000	$4.00	$4.30
Fourth quarter 2015	5,157,000	$3.99	$4.29
All gas collars*	7,162,000		

*Gas collars are comprised of IF El Paso Permian (5%), IF HSC (88%), and IF NNG Ventura (7%).

NGL Contracts

NGL Swaps

Contract Period	Volumes	Weighted-Average Contract Price
	(Bbls)	(per Bbl)
Third quarter 2015	1,739,000	$21.61
Fourth quarter 2015	1,539,000	$21.73
2016	2,017,000	$17.70
2017	792,000	$9.98
2018	1,671,000	$10.65
2019	1,200,000	$10.92
2020	539,000	$11.13
All NGL swaps*	9,497,000	

*NGL swaps are comprised of Oil Price Information System (“OPIS”) Ethane Purity Mont Belvieu (52%), OPIS Propane Mont Belvieu Non-TET (29%), OPIS Normal Butane Mont Belvieu Non-TET (10%), and OPIS Isobutane Mont Belvieu Non-TET (9%).

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 $391.4 million as of June 30, 2015, and net asset of $592.1 million as of December 31, 2014.

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

	As of June 30, 2015			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity contracts	Current assets	$269,022	Current liabilities	$8,107
Commodity contracts	Noncurrent assets	131,464	Noncurrent liabilities	1,026
Derivatives not designated as hedging instruments		$400,486		$9,133

	As of December 31, 2014			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity contracts	Current assets	$402,668	Current liabilities	$—
Commodity contracts	Noncurrent assets	189,540	Noncurrent liabilities	70
Derivatives not designated as hedging instruments		$592,208		$70

Offsetting of Derivative Assets and Liabilities

As of June 30, 2015, and December 31, 2014, all derivative instruments held by the Company were subject to master netting arrangements 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 settle on the same date and in the same currency. The Company's agreements also provide that in the event of an early termination, the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. The Company's accounting policy is to not offset these positions in its accompanying balance sheets.

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

Offsetting of Derivative Assets and Liabilities	Derivative Assets As of June 30, 2015 (in thousands)	Derivative Assets As of December 31, 2014	Derivative Liabilities As of June 30, 2015	Derivative Liabilities As of December 31, 2014
Gross amounts presented in the accompanying balance sheets	$400,486	$592,208	$(9,133)	$(70)
Amounts not offset in the accompanying balance sheets	(9,133)	(70)	9,133	70
Net amounts	$391,353	$592,138	$—	$—

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

	For the Three Months Ended June 30, 2015 (in thousands)	For the Three Months Ended June 30, 2014	For the Six Months Ended June 30, 2015	For the Six Months Ended June 30, 2014
Derivative settlement (gain) loss:				
Oil contracts	$(73,915)	$20,160	$(180,129)	$26,918
Gas contracts [(1)]	(38,880)	13,472	(73,112)	26,876
NGL contracts	—	48	(20,783)	8,826
Total derivative settlement (gain) loss [(2)]	$(112,795)	$33,680	$(274,024)	$62,620
Total derivative (gain) loss:				
Oil contracts	$66,749	$93,595	$(7,111)	$125,545
Gas contracts	6,070	28,154	(76,269)	87,615
NGL contracts	8,110	4,720	10,142	10,971
Total derivative (gain) loss [(3)]	$80,929	$126,469	$(73,238)	$224,131

(1) Natural gas derivative settlements for the three and six months ended June 30, 2015 include a $15.3 million gain on the early settlement of future contracts as a result of divesting of the Company's Mid-Continent assets during the second quarter of 2015.

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

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

Credit Related Contingent Features

As of June 30, 2015, and through the filing date of this report, all of the Company's derivative counterparties were members of the Company's credit facility lender group. The Company's obligations under its derivative contracts are secured by mortgages on assets having a value equal to at least 75 percent of the total value 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. This 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 table is a listing of the Company's assets and liabilities that are measured at fair value in the accompanying balance sheets and where they are classified within the fair value hierarchy as of June 30, 2015:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives [1]	$—	$400,486	$—
Proved oil and gas properties [2]	$—	$—	$7,658
Oil and gas properties held for sale [2]	$—	$—	$5,801
Liabilities:			
Derivatives [1]	$—	$9,133	$—
Net Profits Plan [1]	$—	$—	$18,326

[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 in the accompanying balance sheets and where they were classified within the hierarchy as of December 31, 2014:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives [1]	$—	$592,208	$—
Proved oil and gas properties [2]	$—	$—	$33,423
Oil and gas properties held for sale [2]	$—	$—	$17,891
Liabilities:			
Derivatives [1]	$—	$70	$—
Net Profits Plan [1]	$—	$—	$27,136

[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 that is measured at fair value on a nonrecurring basis.

Both financial and non-financial assets and liabilities are categorized within the above fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. The following is a description of the valuation methodologies used by the Company as well as the general classification of such instruments pursuant to the above fair value hierarchy.

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Derivatives

The Company uses Level 2 inputs to measure the fair value of oil, gas, and NGL commodity derivatives. Fair values are based upon interpolated data. The Company derives internal valuation estimates taking into consideration forward commodity price curves, 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 require counterparties to post collateral if their ratings deteriorate. In some instances, the Company will attempt to novate the trade to a more stable counterparty.

Valuation adjustments are necessary to reflect the effect of the Company's credit quality on the fair value of any derivative liability position. 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 lender group.

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 authoritative accounting 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 valuation technique, 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. A discount rate of 12 percent is used to calculate this liability and is intended to represent the Company's best estimate of the present value of expected future payments under the Net Profits Plan.

The Company's estimate of its liability is highly dependent on commodity prices, cost assumptions, discount rates, and overall market conditions. The Company regularly assesses the current market environment. The Net Profits Plan liability is determined using price assumptions of five one-year strip prices with the fifth year's pricing then carried out indefinitely. The average price is adjusted for realized price differentials and to include the effects of the forecasted production covered by derivative 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.

If the commodity prices used in the calculation changed by five percent, the liability recorded at June 30, 2015, would differ by approximately $1.8 million. A one percent increase or decrease in the discount rate would result in a change of approximately $650,000. 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 of 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, 2015	
	(in thousands)	
Beginning balance	$27,136	
Net decrease in liability [1]	(1,796	)
Net settlements [1] [2]	(7,014	)
Transfers in (out) of Level 3	—	
Ending balance	$18,326	

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(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 amount in the table includes cash payments made or accrued under the Net Profits Plan of $3.8 million for the six-month period ended June 30, 2015, as a result of the divestitures of properties subject to the Net Profits Plan.

Long-term Debt

The following table reflects the fair value of 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, 2015, or December 31, 2014, as they are recorded at historical value.

	As of June 30, 2015	As of December 31, 2014
	(in thousands)	
6.625% Senior Notes due 2019	$—	$350,018
6.50% Senior Notes due 2021	$362,250	$343,000
6.125% Senior Notes due 2022	$621,000	$556,500
6.50% Senior Notes due 2023	$412,000	$379,000
5.0% Senior Notes due 2024	$471,250	$435,000
5.625% Senior Notes due 2025	$493,850	$—

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

Proved and Unproved Oil and Gas Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication 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, 2015, and December 31, 2014. The Company believes 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 forecast 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 forecast using OPIS Mont Belvieu pricing, 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. The Company recorded impairment of proved oil and gas properties of $12.9 million and $68.4 million for the three months and six months ended June 30, 2015, respectively, due to continued declines in commodity strip prices since year-end 2014, the Company's decision to reduce capital invested in the development of certain prospects in its South Texas & Gulf Coast and Permian regions, and a decline in performance of non-core assets. Proved properties measured at fair value within the accompanying balance sheets totaled $7.7 million as of June 30, 2015. As of December 31, 2014, proved oil and gas properties measured at fair value totaled $33.4 million.

Proved properties classified as held for sale, including the corresponding asset retirement obligation liability, 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 available. If an estimated selling price is not available, the Company utilizes the income valuation technique discussed above. For the three and six months ended June 30, 2015, the Company recorded write-downs to fair value less estimated costs to sell of $66.0 million and $99.9 million, respectively, for certain assets held for sale. These write-downs are included within the net gain on divestiture activity line item on the accompanying statements of operations. Please refer to Note 3 – Acquisitions, Divestitures, and Assets Held for Sale.

Unproved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. To measure the fair value of unproved properties, the Company uses a market approach, which takes into account the following significant assumptions: future development plans, risk weighted potential resource recovery, and estimated reserve values. Unproved properties classified as held for sale are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties. If an estimated selling price is not available, the Company 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. The Company recorded abandonment and impairment of unproved oil and gas properties expense of $5.8 million and $17.4 million for the three and six months ended June 30, 2015, respectively, related to acreage the Company no longer intends to develop. Unproved properties measured at fair value were written down to zero in the accompanying balance sheets as of June 30, 2015, and December 31, 2014.

The fair value measurements of assets acquired and liabilities assumed are measured on a nonrecurring basis on the acquisition date using an income valuation technique based on inputs that are not observable in the market and therefore represent Level 3 inputs. Significant inputs to the valuation of acquired oil and gas properties include estimates of: (i) reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices, including price differentials; (v) future cash flows; and (vi) a market participant-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Company's management at the time of the valuation.

Note 12 - Suspended Well Costs

For the three and six months ended June 30, 2015, the Company charged to exploration expense $6.0 million and $21.1 million, respectively, of capitalized exploratory well costs as of December 31, 2014. These costs were related to two wells, for which none of the costs were capitalized for a period greater than one year as of December 31, 2014, or at the time the wells were determined to be unsuccessful.

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. We have large positions in the Eagle Ford shale and Bakken/Three Forks resource plays that are the focus of our development investment programs. We also have a smaller development program in the Permian Basin and delineation and exploration programs in the Powder River Basin and in east Texas. We have built a portfolio of onshore properties 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.

Our strategic objective is to build our ownership and operatorship of North American oil, gas and NGL producing assets that have high operating margins and significant opportunities for additional economic investment. We pursue opportunities through both acquisitions and exploration, and seek to maximize the value of our assets through industry leading technology application and outstanding operational execution. We focus on returns and maintain a simple, strong balance sheet through a conservative approach to leverage.

In the second quarter of 2015, we had the following financial and operational results:

- Average net daily production for the three months ended June 30, 2015, was 55.9 MBbls of oil, 485.8 MMcf of gas, and 44.2 MBbls of NGLs, for a quarterly equivalent daily production rate of 181.0 MBOE, compared with 147.0 MBOE for the same period in 2014. Please see additional discussion below under Production Results.

- We recorded a net loss of $57.5 million, or $0.85 per diluted share, for the three months ended June 30, 2015, compared to net income for the three months ended June 30, 2014, of $59.8 million, or $0.88 per diluted share. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2015, and 2014 below for additional discussion regarding the components of net income (loss).

- Costs incurred for oil and gas property acquisitions and exploration and development activities for the three months ended June 30, 2015, totaled $354.0 million. The majority of our drilling and completion costs incurred during this period were in our Eagle Ford shale and Bakken/Three Forks programs. Total costs incurred for the same period in 2014 were $677.4 million, which included approximately $100.0 million related to unproved property acquisitions in the Powder River Basin. Please refer to Overview of Liquidity and Capital Resources below for additional discussion on how we expect to fund our capital program.

- Adjusted EBITDAX, a non-GAAP financial measure, for the three months ended June 30, 2015, was $337.3 million, compared to $423.4 million for the same period in 2014. Please refer to Non-GAAP Financial Measures below for additional discussion, including our definition of adjusted EBITDAX and reconciliations of our GAAP net income (loss) and net cash provided by operating activities to adjusted EBITDAX.

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 higher 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 is sold using contracts paying us various industry posted prices, adjusted for basis differentials. We are paid the average of the daily settlement price for the respective posted prices for the period in which the product is sold, adjusted for quality, transportation, American Petroleum Institute ("API") gravity, and location differentials. When we refer to realized oil, gas, and NGL prices below, the disclosed price represents the average price for the respective period, before the effects of derivative settlements, unless otherwise indicated.

The following table summarizes commodity price data, as well as the effects of derivative settlements, for the first and second quarters of 2015, as well as the second quarter of 2014:

	For the Three Months Ended		
	June 30, 2015	March 31, 2015	June 30, 2014
Crude Oil (per Bbl):			
Average daily NYMEX price	$57.85	$48.49	$103.06
Realized price, before the effect of derivative settlements	$51.45	$38.56	$91.78
Effect of derivative settlements	$14.53	$20.33	$(5.18)
Natural Gas:			
Average daily NYMEX price (per MMBtu)	$2.73	$2.87	$4.59
Realized price, before the effect of derivative settlements (per Mcf)	$2.53	$2.76	$4.87
Effect of derivative settlements (per Mcf) (1)	$0.88	$0.75	$(0.36)
Natural Gas Liquids (per Bbl):(2)			
Average daily OPIS price	$20.79	$21.53	$41.21
Realized price, before the effect of derivative settlements	$16.85	$16.67	$35.61
Effect of derivative settlements	$—	$5.33	$(0.02)

(1) Natural gas derivative settlements for the three months ended June 30, 2015, includes a $15.3 million gain on the early settlement of future contracts as a result of divesting our Mid-Continent assets during the second quarter of 2015, increasing the effect of derivative settlements by $0.35 per Mcf.

(2) Average OPIS prices per barrel of NGL, historical or strip, 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. Realized prices reflect our actual product mix.

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.

We expect future prices for oil, gas, and NGLs to be volatile. In addition to supply and demand fundamentals, as a global commodity, the price of oil will continue to be impacted by real or perceived geopolitical risks in oil producing regions of the world, particularly the Middle East. The relative strength of the U.S. dollar compared to other currencies also affects the price of oil. Lower forecasted levels of global economic growth combined with excess global supply have weighed on oil prices in recent months. This was exacerbated by the decision of the Organization of Petroleum Exporting Countries ("OPEC") not to cut production in November of 2014. In response to lower oil prices at the end of 2014 and the first half of 2015, industry participants have significantly cut capital spending, which we expect will result in lower supply. The prices of several NGL products generally correlate to the price of oil, and accordingly, prices for these products have fallen in recent months and are likely to continue to directionally follow that market. Further, excess supply of ethane and propane with higher volumes in storage than historical averages has resulted in a further drop in pricing for those products in recent months. Gas prices have been under downward pressure recently due to higher levels of gas in storage compared to last year and compared to the 5-year average. Longer term, we anticipate natural gas prices will trade in a range higher than current price levels. Changes to existing laws and regulations pertaining to the ability to export oil, gas, and NGLs also have the potential to impact the prices for these commodities. The following table 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 July 22, 2015, and June 30, 2015:

	As of July 22, 2015	As of June 30, 2015
NYMEX WTI oil (per Bbl)	$52.19	$60.51
NYMEX Henry Hub gas (per MMBtu)	$3.10	$3.05
OPIS NGLs (per Bbl)	$20.42	$22.32

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 current year operations and have partially reduced our exposure to volatility in commodity prices in the near term. Our use of costless collars for a portion of our derivatives allows us to participate in some of the upward movements in oil and gas 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 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 of these new rules on our business 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.

Second Quarter 2015 Highlights and Outlook for the Remainder of 2015

Operational Activities. We view 2015 as a year of transition as the broader oil and gas industry adjusts to lower oil prices. We began to scale back activity during the first half of 2015 and continue to curtail activity, including the deferral of the completion of certain drilled wells. Our goal is to be well positioned entering 2016 to take advantage of what we expect will be a stronger commodity price and lower service cost environment, while having the strength and flexibility to adapt should industry conditions change.

We expect our capital program for 2015 to be approximately $1.28 billion, which is $50 million higher than our original budget due to partner non-consents and higher than projected partner operated costs in the first half of 2015. For the six months ended June 30, 2015, we have incurred approximately $819.1 million for exploration and development activities, primarily excluding proved property acquisitions, estimated asset retirement obligations, and capitalized interest. Please refer to the captions titled Costs Incurred in Oil and Gas Producing Activities below.

We substantially reduced our activity during the second quarter by releasing rigs in all regions and deferring completions. We expect to further decrease activity for the last half of 2015, which, combined with the decreased service provider costs we are realizing, will allow us to reduce capital spending for the remainder of the year.

We began the second quarter of 2015 with five drilling rigs in our operated Eagle Ford shale program in South Texas and released a rig at the end of the quarter. We plan to maintain a four rig program for the remainder of the year. During 2014, our development program shifted to utilizing longer laterals and completions with higher sand loadings. Results from these enhanced completion techniques suggest significantly improved well performance. For the remainder of the year, we will continue to test well and completion design and spacing and the prospectivity of the Upper Eagle Ford on our acreage.

In our non-operated Eagle Ford shale program, the operator ran five rigs during the second quarter of 2015. The operator has indicated it will continue to evaluate rig count as it pertains to contracts, drilling obligations, and changes in commodity prices.

In our Bakken/Three Forks program, we began the second quarter of 2015 operating five drilling rigs. We released a rig during the second quarter and expect to release another two rigs by the end of 2015, exiting the year with two operated rigs. We continue to focus most of our 2015 activity in Divide County, North Dakota, where we are developing the Three Forks and Bakken intervals. We are monitoring the results of various tests, including completion optimizations and down-spacing of both our operated and non-operated properties in this area.

In our Permian development program, we released our last operated rig during the second quarter of 2015. A large portion of our leasehold position in this region is held by production. When oil prices recover appropriately, we expect to return to the development of the Wolfcamp and Spraberry intervals on our Sweetie Peck property in Upton County, Texas.

Given the current commodity price environment, we have curtailed activity in our delineation and exploration programs. We have reduced our activity in the Powder River Basin in Wyoming and in east Texas, while focusing on preserving more prospective acreage positions. In our Powder River Basin program, we released a rig at the beginning of the second quarter and plan to operate one rig for the remainder of the year. In east Texas, we are monitoring the performance of wells previously drilled and completed.

We will continue to evaluate our rig count throughout the year and into next year as we respond to commodity price changes and reduced costs. Please refer to Overview of Liquidity and Capital Resources below for additional discussion regarding how we intend to fund our 2015 capital program.

Production Results. The table below provides a regional breakdown of our production for the second quarter of 2015:

	South Texas & Gulf Coast	Rocky Mountain	Permian	Mid-Continent	Total [1]
Oil (MMBbl)	2.1	2.5	0.5	—	5.1
Gas (Bcf)	36.7	2.3	1.4	3.9	44.2
NGLs (MMBbl)	3.9	0.1	—	—	4.0
Equivalent (MMBOE)	12.1	3.0	0.7	0.7	16.5
Avg. daily equivalents (MBOE/d)	133.0	32.4	8.1	7.4	181.0
Relative percentage	74 %	18 %	4 %	4 %	100 %

(1) Amounts may not calculate due to rounding.

Production increased for the three months ended June 30, 2015, compared to the same period in 2014, driven primarily 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, 2015, and 2014 and A three-month and six-month overview of selected production and financial information, including trends below for additional discussion on production.

Costs Incurred in Oil and Gas Producing Activities. Costs incurred in oil and gas property acquisition, exploration and development activities, whether capitalized or expensed, are summarized as follows:

	For the Three Months Ended June 30, 2015 (in millions)
Development costs [1]	$315.3
Exploration costs	34.0
Acquisitions	
Proved properties	—
Unproved properties	4.7
Total, including asset retirement obligations [2]	$354.0

(1) Includes facility costs of $22.6 million and support facility allocations of $1.3 million for the three months ended June 30, 2015.
(2) Includes amounts relating to estimated asset retirement obligations of $6.1 million and capitalized interest of $8.0 million for the three months ended June 30, 2015.

Costs incurred in oil and gas producing activities, excluding estimated asset retirement obligations, capitalized interest, and support facility allocations, for the three months ended June 30, 2015, totaled approximately $338.6 million. The majority of costs incurred for oil and gas producing activities during the second quarter of 2015 were in the development of our Eagle Ford shale and Bakken/Three Forks programs. Please refer to Overview of Liquidity and Capital Resources below for additional discussion on how we expect to fund our capital program.

Mid-Continent Divestitures. During the second quarter of 2015, we completed the divestiture of our Mid-Continent assets in separate packages for total divestiture proceeds of $316.5 million, with an estimated net gain of $107.8 million recorded for the six months ended June 30, 2015. These divestitures are subject to normal post-closing adjustments. Please refer to Note 3 - Acquisitions, Divestitures, and Assets Held for Sale in Part I, Item 1 of this report for additional information.

2025 Notes. On May 21, 2015, we issued $500.0 million in aggregate principal amount of 2025 Notes. The notes were issued at par and mature on June 1, 2025. We received proceeds, net of paid and accrued fees, of $491.1 million from this issuance, which we used to fund the consideration paid to the tendering holders of the 2019 Notes and to redeem the remaining un-tendered 2019 Notes, as well as repay outstanding borrowings under our credit facility and for general corporate purposes. Please refer to Note 5 - Long-term Debt in Part I, Item 1 of this report for additional information.

Credit Facility. During the second quarter of 2015, our borrowing base was reaffirmed by our lenders at $2.4 billion. Please refer to Note 5 - Long-term Debt in Part I, Item 1 of this report for additional discussion.

Equity Compensation. Subsequent to June 30, 2015, we granted 356,246 RSUs and 320,753 PSUs under our long-term equity incentive program. Also subsequent to June 30, 2015, we issued 351,712 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 2015 Highlights

Production Results. The table below provides a regional breakdown of our production for the first six months of 2015:

	South Texas & Gulf Coast	Rocky Mountain	Permian	Mid-Continent	Total [1]
Oil (MMBbl)	4.4	4.8	1.1	—	10.3
Gas (Bcf)	73.5	4.3	2.7	9.7	90.1
NGLs (MMBbl)	7.8	0.1	—	—	7.9
Equivalent (MMBOE)	24.4	5.7	1.5	1.7	33.3
Avg. daily equivalents (MBOE/d)	134.7	31.3	8.4	9.3	183.7
Relative percentage	73 %	17 %	5 %	5 %	100 %

(1) Amounts may not calculate due to rounding.

Please refer to Second Quarter 2015 Highlights and Outlook for the Remainder of 2015 above and Comparison of Financial Results and Trends Between the Six Months Ended June 30, 2015 and 2014 as well as A three-month and six-month overview of selected production and financial information, including trends below for additional discussion on production.

Costs Incurred in Oil and Gas Producing Activities. Costs incurred in oil and gas property acquisition, exploration and development activities, whether capitalized or expensed, are summarized as follows:

	For the Six Months Ended June 30, 2015 (in millions)
Development costs [1]	$754.2
Exploration costs	80.2
Acquisitions	
Proved properties	8.9
Unproved properties	10.4
Total, including asset retirement obligations [2]	$853.7

(1) Includes facility costs of $54.3 million and support facility allocations of $4.1 million for the six months ended June 30, 2015.
(2) Includes amounts relating to estimated asset retirement obligations of $8.7 million and capitalized interest of $12.9 million for the six months ended June 30, 2015.

Costs incurred in oil and gas producing activities, excluding proved property acquisitions, estimated asset retirement obligations, capitalized interest, and support facility allocation amounts disclosed above for the six months ended June 30, 2015, totaled approximately $819.1 million. Please refer to Second Quarter 2015 Highlights and Outlook for the Remainder of 2015 above for additional discussion on 2015 capital spending.

Financial Results of Operations and Additional Comparative Data

The tables below provide information regarding selected production and financial information. A detailed discussion follows.

	For the Three Months Ended June 30, 2015	March 31, 2015	December 31, 2014	September 30, 2014
	(in millions, except for production data)			
Production (MMBOE)	16.5	16.8	16.2	13.1
Oil, gas, and NGL production revenue	$441.3	$393.3	$586.6	$617.2
Oil, gas, and NGL production expense	$173.7	$196.2	$196.2	$178.4
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$219.7	$217.4	$219.3	$183.3
Exploration	$25.5	$37.4	$49.7	$34.6
General and administrative	$42.6	$43.6	$52.2	$41.7
Net income (loss)	$(57.5)	$(53.1)	$331.7	$208.9

Note: Quarterly amounts may not calculate due to rounding.

Selected Performance Metrics:

	For the Three Months Ended June 30, 2015	March 31, 2015	December 31, 2014	September 30, 2014
Average net daily production equivalent (MBOE/d)	181.0	186.4	175.8	142.5
Lease operating expense (per BOE)	$3.26	$3.96	$4.29	$4.58
Transportation costs (per BOE)	$5.64	$6.08	$5.77	$6.22
Production taxes as a percent of oil, gas, and NGL production revenue	5.2%	4.8%	4.7%	4.9%
Ad valorem tax expense (per BOE)	$0.25	$0.52	$0.37	$0.49
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)	$13.34	$12.96	$13.56	$13.97
General and administrative (per BOE)	$2.59	$2.60	$3.23	$3.18

Note: Amounts may not calculate due to rounding.

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

	For the Three Months Ended June 30, 2015	For the Three Months Ended June 30, 2014	Amount Change Between Periods	Percent Change Between Periods	For the Six Months Ended June 30, 2015	For the Six Months Ended June 30, 2014	Amount Change Between Periods	Percent Change Between Periods
Net production volumes [1]								
Oil (MMBbl)	5.1	3.9	1.2	31%	10.3	7.5	2.8	37%
Gas (Bcf)	44.2	38.0	6.2	16%	90.1	73.5	16.6	23%
NGLs (MMBbl)	4.0	3.2	0.9	27%	7.9	6.1	1.9	31%
Equivalent (MMBOE)	16.5	13.4	3.1	23%	33.3	25.9	7.4	29%
Average net daily production [1]								
Oil (MBbl per day)	55.9	42.8	13.1	31%	57.0	41.7	15.3	37%
Gas (MMcf per day)	485.8	417.2	68.6	16%	498.0	406.1	91.9	23%
NGLs (MBbl per day)	44.2	34.7	9.5	27%	43.8	33.4	10.3	31%
Equivalent (MBOE per day)	181.0	147.0	34.0	23%	183.7	142.8	40.9	29%
Oil, gas, and NGL production revenue (in millions)								
Oil production revenue	$261.7	$357.3	$(95.6)	(27)%	$463.2	$682.6	$(219.4)	(32)%
Gas production revenue	111.9	184.9	(73.0)	(39)%	238.7	370.5	(131.8)	(36)%
NGL production revenue	67.7	112.5	(44.8)	(40)%	132.7	224.7	(92.0)	(41)%
Total	$441.3	$654.7	$(213.4)	(33)%	$834.6	$1,277.8	$(443.2)	(35)%
Oil, gas, and NGL production expense (in millions)								
Lease operating expense	$53.8	$55.8	$(2.0)	(4)%	$120.3	$106.5	$13.8	13%
Transportation costs	92.9	83.0	9.9	12%	194.9	162.2	32.7	20%
Production taxes	22.9	31.8	(8.9)	(28)%	41.7	59.3	(17.6)	(30)%
Ad valorem tax expense	4.1	7.0	(2.9)	(41)%	12.9	13.3	(0.4)	(3)%
Total	$173.7	$177.6	$(3.9)	(2)%	$369.8	$341.3	$28.5	8%
Realized price								
Oil (per Bbl)	$51.45	$91.78	$(40.33)	(44)%	$44.92	$90.41	$(45.49)	(50)%
Gas (per Mcf)	$2.53	$4.87	$(2.34)	(48)%	$2.65	$5.04	$(2.39)	(47)%
NGLs (per Bbl)	$16.85	$35.61	$(18.76)	(53)%	$16.76	$37.13	$(20.37)	(55)%
Per BOE	$26.78	$48.93	$(22.15)	(45)%	$25.10	$49.43	$(24.33)	(49)%
Per BOE Data [1]								
Production costs:								
Lease operating expense	$3.26	$4.17	$(0.91)	(22)%	$3.62	$4.12	$(0.50)	(12)%
Transportation costs	$5.64	$6.20	$(0.56)	(9)%	$5.86	$6.27	$(0.41)	(7)%
Production taxes	$1.39	$2.38	$(0.99)	(42)%	$1.25	$2.29	$(1.04)	(45)%
Ad valorem tax expense	$0.25	$0.52	$(0.27)	(52)%	$0.39	$0.52	$(0.13)	(25)%
General and administrative	$2.59	$2.85	$(0.26)	(9)%	$2.59	$2.83	$(0.24)	(8)%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$13.34	$14.03	$(0.69)	(5)%	$13.14	$14.12	$(0.98)	(7)%
Derivative settlement gain (loss) [2]	$6.85	$(2.52)	$9.37	372%	$8.24	$(2.43)	$10.67	439%
Earnings per share information								
	$(0.85)	$0.89	$(1.74)	(196)%	$(1.64)	$1.87	$(3.51)	(188)%

Basic net income (loss) per common share								
Diluted net income (loss) per common share	$(0.85)	$0.88	$(1.73)	(197)%	$(1.64)	$1.84	$(3.48)	(189)%
Basic weighted-average common shares outstanding (in thousands)	67,483	67,069	414	1 %	67,473	67,063	410	1 %
Diluted weighted-average common shares outstanding (in thousands)	67,483	68,239	(756)	(1)%	67,473	68,180	(707)	(1)%

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(1) Amount and percentage changes may not calculate due to rounding.
(2) Derivative settlements for the three and six months ended June 30, 2015, and 2014, respectively, are included within the derivative (gain) loss line item in the accompanying statements of operations. Natural gas derivative settlements for the three and six months ended June 30, 2015,

include a $15.3 million gain on the early settlement of future contracts as a result of divesting our Mid-Continent assets during the second quarter of 2015. This settlement gain increased our realized natural gas price after the effect of derivative settlements $0.35 and $0.17 per Mcf for the three and six months ended June 30, 2015, respectively.

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 production for the three and six months ended June 30, 2015, increased 23 percent and 29 percent, respectively, compared with the same periods in 2014, driven primarily by the continued development of our Eagle Ford shale and Bakken/Three Forks programs. Overall, we expect an increase in production in 2015 from 2014 based on our forecasted drilling plan, even in light of divesting our Mid-Continent assets in the second quarter of 2015. We expect production to decline quarter over quarter for the remainder of 2015 resulting in a decrease in absolute operating expenses. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2015, and 2014 below for additional discussion.

Changes in production volumes, revenues, and costs reflect the highly volatile nature of our industry. Our realized price on a per BOE basis for the three and six months ended June 30, 2015, decreased 45 percent and 49 percent, respectively, compared to the same periods in 2014 as a result of significantly lower commodity prices.

Lease operating expense (“LOE”) on a per BOE basis for the three and six months ended June 30, 2015, decreased 22 percent and 12 percent, respectively, compared to the same periods in 2014. Our LOE is comprised of recurring LOE and workover expense. We experience volatility in our LOE as a result of the impact industry activity has on service provider costs and seasonality in workover expense. Industry activity has significantly decreased in light of the weak commodity price environment resulting in service providers lowering costs. While we have experienced lower service provider costs to date, we expect LOE on a per BOE basis to be higher for the remainder of the year compared to what we experienced through the first half of 2015 due to the fixed cost components of our recurring LOE and the expected decline in quarterly production. Overall, we expect LOE on a per BOE basis to be lower for the full-year 2015 compared to the full-year 2014.

Transportation costs on a per BOE basis for the three and six months ended June 30, 2015, decreased nine percent and seven percent, respectively, compared to the same periods in 2014 due to lower deficiency fees and trucking costs recorded in the first half of 2015. Our production mix will change as a result of divesting our Mid-Continent assets during the second quarter. These assets had lower transportation costs on a per BOE basis, so we expect that the divestitures will increase our company-wide transportation costs on a per BOE basis for the third and fourth quarters. Overall, we expect the increase in transportation costs to be relatively in line with increased production for the full-year 2015 compared to full-year 2014, resulting in minimal change on a per BOE basis year over year.

Production taxes on a per BOE basis for the three and six months ended June 30, 2015, decreased 42 percent and 45 percent, respectively, in line with the decrease in production revenues, compared to the same periods in 2014. We generally expect absolute production tax expense to trend with oil, gas, and NGL production revenue. Product mix, the location of production, and incentives to encourage oil and gas development can all impact or change the amount of production tax we recognize. We expect an overall decrease in our company-wide production tax rate as a result of divesting our Mid-Continent properties.

Ad valorem tax expense on a per BOE basis for the three and six months ended June 30, 2015, decreased 52 percent and 25 percent, respectively, compared to the same periods in 2014. The decrease in ad valorem tax expense on a per BOE basis for the three and six months ended June 30, 2015, reflects the uncertain nature of estimating this amount in a fluctuating commodity price environment. We expect ad valorem tax expense to fluctuate throughout the year on an absolute and on a per BOE basis as valuations and county tax rates are finalized with an overall decrease on a per BOE basis when comparing full-year 2015 to full-year 2014.

General and administrative (“G&A”) expense on a per BOE basis for the three and six months ended June 30, 2015, decreased nine percent and eight percent, respectively, compared to the same periods in 2014, as production increased at a faster rate than our general and administrative expense. A portion of our general and administrative expense is linked to our profitability and cash flow, which are driven in large part by the realized commodity prices we receive for our production. A portion of our short-term incentive compensation correlates with net cash flows and therefore is subject to variability. We expect the increase in production to be greater than the increase in G&A expense for the full-year 2015 compared to 2014, resulting in a decrease in G&A expense on a per BOE basis. Please refer to Note 3 - Acquisitions, Divestitures, and Assets Held for Sale in Part I, Item 1 of this report for discussion on incurred exit and disposal costs for the first half of 2015 and the additional costs expected to be incurred relating to the closure of our Tulsa office.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion (“DD&A”) expense on a per BOE basis for the three and six months ended June 30, 2015, decreased five percent and seven percent, respectively, compared to the same periods in 2014. Our DD&A rate can fluctuate as a result of impairments, planned and closed divestitures, and changes in the mix of our production and the underlying proved reserve volumes. Our DD&A rate has decreased as assets with lower finding and development costs have become a larger portion of our total production mix. Our finding and development costs have benefited from a general decrease in well costs and an increase in recoveries per well, as well as from our outside-operated Eagle Ford shale program, where, throughout the first half of 2014 and several years prior to 2014, we added reserves with minimal associated costs due to the capital cost carry under our Acquisition and Development Agreement with Mitsui E&P Texas LP. This carry was exhausted during the second quarter of 2014. We expect our DD&A rate to increase in future periods as we now pay our full share of costs in our outside-operated Eagle Ford shale program. Additionally, during the first quarter of 2015, we began marketing for sale all of our Mid-Continent assets, which decreased DD&A on a per BOE basis, as these assets were held for sale, and therefore, no DD&A expense was recorded for these assets for the majority of the first half of 2015. We expect an increase in our DD&A expense on a per BOE basis for the last half of 2015 as a result of a reduction in commodity prices.

Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2015, and 2014 below for additional discussion on operating expenses.
Please refer to Note 9 - Earnings Per Share in Part I, Item 1 of this report for discussion on the types of shares included in our basic and diluted net income (loss) per common share calculations. For the three and six months ended June 30, 2015, we recorded a loss from continuing operations and all potentially dilutive shares were anti-dilutive and excluded from the calculation of diluted net loss per common share.

Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2015, and 2014

Oil, gas, and NGL production, revenue, and costs. The following table presents the regional changes in our oil, gas, and NGL production, revenue, and costs between the three months ended June 30, 2015, and 2014:

	Average Net Daily Production Increase (Decrease) (MBOE/d)	Oil, Gas, & NGL Production Revenue Decrease (in millions)	Production Costs Increase (Decrease) (in millions)
South Texas & Gulf Coast	24.7	$(135.5)	$5.8
Rocky Mountain	10.9	(36.1)	(0.2)
Permian	0.6	(23.8)	(6.0)
Mid-Continent	(2.2)	(18.0)	(3.5)
Total	34.0	$(213.4)	$(3.9)

Our 23 percent increase in equivalent production volumes is offset by a 45 percent decrease in realized prices on a per BOE basis resulting in a 33 percent decrease in oil, gas, and NGL production revenue between the two periods. Please refer to A three-month and six-month overview of selected production and financial information, including trends above for realized prices received before the effects of derivative settlements for the three months ended June 30, 2015, and 2014. We expect our realized prices to trend with commodity prices.

Net gain on divestiture activity. We recorded a net gain on divestiture activity of $71.9 million for the three months ended June 30, 2015, due to the gain recorded on the sale of our Mid-Continent assets, partially offset by the write-down to fair value of certain assets held for sale as of June 30, 2015. We recorded a net gain on divestiture activity of $2.5 million for the same period in 2014. Please refer to Note 3 - Acquisitions, Divestitures, and Assets Held for Sale in Part I, Item 1 of this report for additional discussion.

Other operating revenues. Other operating revenues consist primarily of marketed gas system revenues. The decrease for the three months ended June 30, 2015, compared to the same period in 2014, is driven by a decrease in natural gas prices and a decrease in marketed gas volumes during the second quarter of 2015 as a result of our Mid-Continent asset divestitures. Other operating revenues should significantly decrease in the last half of 2015 with no further revenue stream from our recently divested properties.

Oil, gas, and NGL production expense. Total production costs decreased two percent for the three months ended June 30, 2015, compared with the same period of 2014, as a result of lower service provider costs and decreased production taxes resulting from lower commodity prices. These reductions were partially offset by additional transportation expense resulting from an increase in net equivalent production volumes. Please refer to 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 17 percent for the three-month period ended June 30, 2015, compared with the same period in 2014. Increased production is driving DD&A expense higher in 2015, but DD&A expense on a per BOE basis is lower period over period. Please refer to A three-month and six-month overview of selected production and financial information, including trends above for additional discussion.

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

	For the Three Months Ended June 30,	
	2015	2014
	(in millions)	
Geological and geophysical expenses	$1.0	$1.7
Exploratory dry hole	6.6	6.5
Overhead and other expenses	17.9	16.1
Total	$25.5	$24.3

Exploration expense for the three months ended June 30, 2015, increased five percent compared to the same period in 2014, as a result of higher overhead costs. During the second quarter of 2015, we expensed $6.6 million to exploratory dry hole expense upon abandoning an exploratory well as a result of a mechanical failure. During the same period in 2014, we expensed $6.5 million due to a well deemed non-commercial. 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.

Impairment of proved properties. We recorded $12.9 million of impairment of proved properties expense for the three months ended June 30, 2015, due to a decline in performance on certain non-Eagle Ford assets in our South Texas & Gulf Coast region. We recorded no impairment of proved properties in the second quarter of 2014. We expect impairments of proved properties to be more likely to occur in periods of declining commodity prices.

Abandonment and impairment of unproved properties. We recorded $5.8 million of abandonment and impairment of unproved properties expense for the three months ended June 30, 2015, compared to approximately $164,000 of expense recorded in the same period of 2014, related to acreage we no longer intended to develop. We expect our abandonment and impairment of unproved properties expense to fluctuate with the timing of lease expirations, unsuccessful exploration activities, and changing economics associated with volatile commodity prices.

General and administrative. G&A expense increased 12 percent for the three months ended June 30, 2015, compared with the same period of 2014. The increase is due to approximately $5.0 million of exit and disposal costs recorded during the second quarter of 2015 related to the closure of our Tulsa office. Please refer to 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 (benefit) generally relates to the change in the estimated value of the associated liability between the reporting periods. For the three months ended June 30, 2015, and 2014, we recorded a non-cash benefit of $4.5 million and $7.1 million, respectively, as a result of divestitures of properties subject to the Net Profits Plan in each of these periods. We generally expect changes in our Net Profits Plan liability to correlate with fluctuations in commodity prices.

Derivative (gain) loss. We recognized a derivative loss of $80.9 million for the three-month period ended June 30, 2015, driven by a decrease in the fair value of commodity derivative contracts during the period as strip pricing improved slightly. This compares to a derivative loss of $126.5 million for the same period in 2014, resulting from a decrease in the fair value of commodity derivative contracts during the period due to an increase in strip prices during the period. For the three months ended June 30, 2015, we realized a $15.3 million gain on the early settlement of derivative contracts as a result of divesting our Mid-Continent assets. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information.

Other operating expenses. For the three months ended June 30, 2015, and 2014, we recorded other operating expenses of $10.3 million and $6.0 million, respectively. The increase is primarily due to $2.7 million of expense related to the early termination of drilling rig contracts, $4.7 million related to estimated claims for payment of royalties on certain Federal and Indian leases, and a $1.4 million materials inventory write-down during the second quarter of 2015. Other operating expenses also includes marketed gas system expense, which decreased for the three months ended June 30, 2015, compared to the same period in 2014, in line with the decrease in marketed gas revenues discussed above under other operating revenues. With the exception of non-recurring items, we expect other operating expenses to decrease in the last half of 2015 with no further expenses incurred on our recently divested properties.

Loss on extinguishment of debt. For the three months ended June 30, 2015, we recorded a $16.6 million loss on the early extinguishment of our 2019 Notes, which includes approximately $12.5 million associated with the premium paid for the tender offer and redemption of the notes and approximately $4.1 million for the acceleration of unamortized deferred financing costs. Please refer to Note 5 - Long-term Debt in Part I, Item 1 of this report for additional information.

Income tax expense (benefit). We recorded income tax benefit of $40.7 million for the three-month period ended June 30, 2015, compared to expense of $36.0 million for the same period in 2014, resulting in effective tax rates of 41.4 percent and 37.6 percent, respectively. The 2015 benefit tax rate is higher than the 2014 expense tax rate due to effects of state tax rate changes, finalizing a claimed R&D credit in 2015, and state apportionment factor changes between periods. Property sales during the three months ended June 30, 2015, resulted in an increase in current tax liabilities. Please refer to Note 4 - Income Taxes in Part I, Item 1 of this report for additional discussion.

Comparison of Financial Results and Trends Between the Six Months Ended June 30, 2015, and 2014

Oil, gas, and NGL production, revenue, and costs. The following table presents the regional changes in our oil, gas, and NGL production, revenue, and costs between the six months ended June 30, 2015, and 2014:

	Average Net Daily Production Increase (Decrease) (MBOE/d)	Oil, Gas, & NGL Production Revenue Decrease (in millions)	Production Costs Increase (Decrease) (in millions)
South Texas & Gulf Coast	29.8	$(273.8)	$35.9
Rocky Mountain	10.0	(98.8)	2.5
Permian	1.3	(43.2)	(4.4)
Mid-Continent	(0.2)	(27.4)	(5.5)
Total	40.9	$(443.2)	$28.5

Our 29 percent increase in equivalent production volumes is offset by a 49 percent decrease in realized prices on a per BOE basis resulting in a 35 percent decrease in oil, gas, and NGL production revenue between the two periods. Please refer to A three-month and six-month overview of selected production and financial information, including trends above for realized prices received before the effects of derivative settlements for the six months ended June 30, 2015, and 2014.

Net gain on divestiture activity. We recorded a net gain on divestiture activity of $36.1 million for the six months ended June 30, 2015, due to the net gain recorded on the sale of our Mid-Continent assets in the second quarter, partially offset by the write-down to fair value of certain assets held for sale in both the first and second quarters of 2015. We recorded a net gain on divestiture activity of $5.5 million for the same period in 2014. Please refer to Note 3 - Acquisitions, Divestitures, and Assets Held for Sale in Part I, Item 1 of this report for additional discussion.

Other operating revenues. Other operating revenues consists primarily of marketed gas system revenues, which decreased for the six months ended June 30, 2015, compared to the same period in 2014. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2015, and 2014 for additional discussion.

Oil, gas, and NGL production expense. Total production costs increased eight percent for the six months ended June 30, 2015, compared with the same period of 2014, as a result of a 29 percent increase in net equivalent production volumes, largely offset by lower service provider costs and decreased production taxes resulting from lower commodity prices. Please refer to 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 20 percent for the six-month period ended June 30, 2015, compared with the same period in 2014. This increase is mainly due to the increase in production volumes between the two periods. Please refer to 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,	
	2015	2014
	(in millions)	
Geological and geophysical expenses	$4.7	$5.8
Exploratory dry hole	22.9	6.5
Overhead and other expenses	35.3	33.3
Total	$62.9	$45.6

Exploration expense for the six months ended June 30, 2015, increased 38 percent compared to the same period in 2014, due primarily to expensing $16.3 million for an exploratory dry hole in our Rocky Mountain region in the first quarter of 2015, as the exploratory dry holes recorded in the second quarters of 2015 and 2014 were similar in cost.

Impairment of proved properties. We recorded $68.4 million of impairment of proved properties expense for the six months ended June 30, 2015, due to further decline in commodity strip prices since year-end 2014 and our decision to reduce capital invested in the development of certain prospects in our South Texas & Gulf Coast and Permian regions during the first quarter of 2015 and a decline in performance on certain non-Eagle Ford assets during the second quarter of 2015. We recorded no impairment of proved properties expense in the first half of 2014. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2015, and 2014 for additional discussion.

Abandonment and impairment of unproved properties. We recorded $17.4 million of abandonment and impairment of unproved properties expense for the six months ended June 30, 2015, compared to $3.0 million of expense recorded in the same period of 2014, related to acreage we no longer intended to develop.

General and administrative. G&A expense increased 18 percent for the six months ended June 30, 2015, compared with the same period of 2014. The increase is primarily driven by approximately $8.5 million of exit and disposal costs recorded during the six months ended June 30, 2015 related to the closure of our Tulsa office. Please refer to 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. For the six months ended June 30, 2015, and 2014, we recorded a non-cash benefit of $8.8 million and $8.9 million, respectively. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2015, and 2014 for additional discussion.

Derivative (gain) loss. We recognized a derivative gain of $73.2 million for the six-month period ended June 30, 2015, driven by an increase in the fair value of commodity derivative contracts resulting from the significant decline in strip pricing during the first quarter of 2015, partially offset by a recovery in strip pricing in the second quarter. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2015, and 2014 for discussion of the gain recorded on the early settlement of derivatives. This compares to a derivative loss of $224.1 million for the same period in 2014, resulting from a decrease in the fair value of commodity derivative contracts during the period due to an increase in strip prices. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information.

Other operating expenses. For the six months ended June 30, 2015, and 2014, we recorded other operating expenses of $27.4 million and $14.1 million, respectively. The increase is primarily due to $5.9 million of expense related to the early termination of drilling rig contracts, as well as a $2.9 million materials inventory write-down during the first six months of 2015. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2015, and 2014 for additional discussion on the accrued estimated claims for payment of royalties on certain Federal and Indian leases recorded during the second quarter of 2015 and the decrease in marketed gas system expense period over period.

Loss on extinguishment of debt. For the six months ended June 30, 2015, we recorded a $16.6 million loss on the early extinguishment of our 2019 Notes. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2015, and 2014 above for additional discussion.

Income tax expense (benefit). We recorded income tax benefit of $74.2 million for the six-month period ended June 30, 2015, compared to expense of $74.9 million for the same period in 2014, resulting in effective tax rates of 40.1 percent and 37.4 percent, respectively. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2015, and 2014 for additional discussion.

Overview of Liquidity and Capital Resources

We believe we have sufficient liquidity and capital resources to execute our business plan for the foreseeable future. We continue to manage the duration and level of our drilling and completion service commitments to maintain the flexibility to adjust our activity and capital expenditures in periods of prolonged weak commodity prices.

Sources of Cash

We currently expect our remaining 2015 capital program to be funded by cash flows from operations and proceeds from recent divestitures, supplemented by borrowings under our credit facility. Although we anticipate cash flows from these sources will be sufficient to fund our remaining expected 2015 capital program, we may also elect to access the capital markets, depending on prevailing market conditions, as well as divest of additional non-strategic oil and gas properties to provide additional sources of funding. 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 our most recent borrowing base redetermination.

Proposals to reform the IRC, which include eliminating or reducing current tax deductions for intangible drilling costs, depreciation of equipment acquisition costs, the domestic production activities deduction, percentage depletion, and other deductions which reduce our taxable income, continue to circulate. We expect that future 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, as well as funding available to our peers in the industry for similar programs. If enacted, these reductions in available deductions could have a significant adverse effect on drilling in the United States for a number of years.

Credit Facility

Our credit facility has a maximum loan amount of $2.5 billion, current aggregate lender commitments of $1.5 billion, and a maturity date of December 10, 2019. Our borrowing base is subject to regular semi-annual redeterminations and was reaffirmed in April 2015 at $2.4 billion. In the Third Amendment to the Credit Agreement dated May 20, 2015, the lenders agreed not to reduce the $2.4 billion borrowing base as a result of the issuance of the 2025 Notes and the Mid-Continent divestitures. We believe the current commitment amount is sufficient to meet our anticipated liquidity and operating needs. No individual bank participating in our credit facility represents more than 10 percent of the lending commitments under the credit facility. Borrowings under our credit facility are secured by mortgages on assets having a value equal to at least 75 percent of the total value of our proved oil and gas properties. Please refer to Note 5 - Long-term Debt in Part I, Item 1 of this report for additional discussion as well as the presentation of the outstanding balance, total amount of letters of credit, and available borrowing capacity under our credit facility as of July 22, 2015, June 30, 2015, and December 31, 2014.

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 adjusted EBITDAX, as defined by our Credit Agreement as the ratio of debt to 12-month trailing adjusted 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. 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 debt balance was approximately $330.0 million and $321.8 million for the three and six months ended June 30, 2015, respectively. We had no outstanding balance on our credit facility during the three and six months ended June 30, 2014, as cash received upon the divestiture of properties at the end of 2013 and cash flows provided by our operating activities were sufficient in meeting our operating and capital needs at such time. Cash flows provided by our operating activities, proceeds received from divestitures of properties, and the amount of our capital expenditures all impact the amount we have borrowed under our credit facility.
Weighted-Average Interest Rates

Our calculated weighted-average interest rates include paid and accrued interest, fees on the unused portion of the credit facility's aggregate commitment amount, letter of credit fees, and the non-cash amortization of deferred financing costs. Our calculated weighted-average borrowing rates include paid and accrued interest only.

The following table presents our weighted-average interest rates and our weighted-average borrowing rates for the three and six months ended June 30, 2015, and 2014:

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
	2015		2014		2015		2014	
Weighted-average interest rate	5.9	%	6.8	%	6.0	%	6.8	%
Weighted-average borrowing rate	5.5	%	6.1	%	5.5	%	6.1	%

Our weighted-average interest rates and weighted-average borrowing rates in 2015 and 2014 have been impacted by the timing of Senior Notes issuances, the average balance on our revolving credit facility, and the fees paid on the unused portion of our aggregate commitment. The above table does not reflect the approximate $12.5 million premium paid for the tender offer and redemption of the 2019 Notes or the approximate $4.1 million of unamortized deferred financing costs expensed upon extinguishment of these notes. Please refer to Note 5 - Long-term Debt in Part I, Item 1 of this report for additional discussion.

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 2015, we spent $980.7 million for exploration and development capital activities and proved and unproved oil and gas property acquisitions. This amount differs from the costs incurred amount, which is accrual-based and includes asset retirement obligation, geological and geophysical expenses ("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 acquisition 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. During the second quarter of 2015, we conducted a tender offer for and redeemed our 2019 Notes. Please refer to Note 5 - Long-term Debt in Part I, Item 1 of this report for additional discussion.

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 outstanding shares during 2015.

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The following table presents changes in cash flows between the six months ended June 30, 2015, and 2014. 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
	2015	2014		
	(in millions)			
Net cash provided by operating activities	$549.5	$715.2	$(165.7)	(23)%
Net cash used in investing activities	$(646.7)	$(832.6)	$185.9	(22)%
Net cash provided by (used in) financing activities	$97.2	$(1.0)	$98.2	9,820%

Analysis of Cash Flow Changes Between the Six Months Ended June 30, 2015, and 2014

Operating activities. Cash received from oil, gas, and NGL production revenues, net of transportation costs and production taxes, and including derivative cash settlements, decreased for the six months ended June 30, 2015, to $928.1 million compared to $995.0 million for the same period in 2014. Cash paid for LOE, excluding ad valorem tax expense, increased $24.9 million to $129.7 million for the first six months of 2015, compared to the same period in 2014 due to an increase in production volumes partially offset by a reduction in service provider costs. Cash paid for interest, net of capitalized interest, increased $17.5 million for the six months ended June 30, 2015, compared to the same period in 2014. Additionally, we paid approximately $12.5 million associated with the premium for the tender offer and redemption of the 2019 Notes.

Investing activities. Capital expenditures for the first six months of 2015 increased 25 percent due to payment of a significant amount of accrued payables at year-end 2014 being made in the first half of 2015. As noted earlier, we anticipate capital expenditures to be significantly reduced in the last half of 2015 as a result of a reduced operated rig count and lower service provider costs. We had $6.6 million of acquisition activity during the six months ended June 30, 2015, compared to $98.6 million of unproved leasehold acquisitions in the Powder River Basin during the same period in 2014. Net proceeds from the sale of oil and gas properties increased $288.2 million for the six months ended June 30, 2015, compared to the same period in 2014, due to the divestiture of our Mid-Continent assets during the second quarter of 2015.

Financing activities. We received $491.6 million of net proceeds from the issuance of our 2025 Notes in the second quarter of 2015. These proceeds were primarily used for the tender and redemption of the principal amount of $350.0 million of our 2019 Notes. See the Operating Activities section above for discussion of the associated premium paid. We had net repayments under our credit facility of $44.0 million during the six months ended June 30, 2015, and no borrowings or repayments during the same period in 2014.

Interest Rate Risk and Commodity Price Risk

We are exposed to market risk due to the floating interest rate on our revolving credit facility. 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. To the extent that the interest rate is fixed, interest rate changes will affect the credit facility’s fair market value, but will not impact results of operations or cash flows. Conversely, for the portion of the credit facility that has a floating interest rate, interest rate changes will not affect the fair market value, but will impact future 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, 2015, our fixed-rate debt and floating-rate debt outstanding totaled $2.4 billion and $122.0 million, respectively. The carrying amount of our floating rate debt at June 30, 2015, 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 directly 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 changes in supply and demand. The markets for oil, gas, and NGLs have been volatile, especially in recent months, 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 currently in place.

There has been no material change to the interest rate risk analysis or oil and gas price sensitivity analysis previously disclosed. Please refer to Interest Rate Risk and Commodity Price Risk in Management's Discussion and Analysis of Financial Condition and Results of Operations in Part II, Item 7 of our 2014 Form 10-K for further discussion.

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 ("SPEs"), which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. 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. We have not been involved in any unconsolidated SPE transactions in 2015.

Critical Accounting Policies and Estimates

Please refer to the corresponding section in Part II, Item 7 and to Note 1 - Summary of Significant Accounting Policies included in Part II, Item 8 of our 2014 Form 10-K for 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.

Non-GAAP Financial Measures

Adjusted EBITDAX represents income (loss) before interest expense, other non-operating income or expense, income taxes, depreciation, depletion, amortization and accretion expense, exploration expense, property impairments, non-cash stock compensation expense, derivative gains and losses net of settlements, change in the Net Profits Plan liability, and gains and losses on divestitures. Adjusted EBITDAX excludes certain items that we believe affect the comparability of operating results and can exclude items that are generally one-time in nature or whose timing and/or amount cannot be reasonably estimated. Adjusted EBITDAX is a non-GAAP measure that is presented because we believe that it provides useful additional information to investors and analysts, 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 a financial covenant under our credit facility based on our debt to adjusted EBITDAX ratio. In addition, adjusted 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. Adjusted EBITDAX should not be considered in isolation or as a substitute for net income (loss), income (loss) from operations, net cash provided by operating activities, or profitability or liquidity measures prepared under GAAP. Because adjusted EBITDAX excludes some, but not all items that affect net income (loss) and may vary among companies, the adjusted EBITDAX amounts presented may not be comparable to similar metrics of other companies.

The following table provides reconciliations of our net income (loss) and net cash provided by operating activities to adjusted EBITDAX for the periods presented:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)			
Net income (loss) (GAAP)	$(57,508)	$59,780	$(110,566)	$125,387
Interest expense	30,779	24,040	63,426	48,230
Other non-operating (income) expense, net	(25)	1,847	(596)	1,821
Income tax expense (benefit)	(40,703)	36,049	(74,156)	74,912
Depreciation, depletion, amortization, and asset retirement obligation liability accretion	219,704	187,781	437,105	364,996
Exploration [(1)]	23,768	22,603	59,500	42,541
Impairment of proved properties	12,914	—	68,440	—
Abandonment and impairment of unproved properties	5,819	164	17,446	2,965
Stock-based compensation expense	7,191	7,997	13,215	14,341
Derivative (gain) loss	80,929	126,469	(73,238)	224,131
Derivative settlement gain (loss) [(2)]	112,795	(33,680)	274,024	(62,620)
Change in Net Profits Plan liability	(4,476)	(7,105)	(8,810)	(8,881)
Net gain on divestiture activity	(71,884)	(2,526)	(36,082)	(5,484)
Loss on extinguishment of debt	16,578	—	16,578	—
Other, net	1,406	—	2,856	—
Adjusted EBITDAX (Non-GAAP)	337,287	423,419	649,142	822,339
Interest expense	(30,779)	(24,040)	(63,426)	(48,230)
Other non-operating income (expense), net	25	(1,847)	596	(1,821)
Income tax (expense) benefit	40,703	(36,049)	74,156	(74,912)
Exploration [(1)]	(23,768)	(22,603)	(59,500)	(42,541)
Exploratory dry hole expense	6,621	6,459	22,896	6,459
Amortization of deferred financing costs	1,935	1,477	3,892	2,954
Deferred income taxes	(50,829)	35,537	(84,556)	73,911
Plugging and abandonment	(961)	(1,894)	(3,386)	(3,219)

Loss on extinguishment of debt	(12,455)	—	(12,455)	—
Other, net	(3,336)	(1,724)	(3,290)	(4,827)
Changes in current assets and liabilities	1,143	36,690	25,439	(14,960)
Net cash provided by operating activities (GAAP)	$265,586	$415,425	$549,508	$715,153

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(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 for the component of stock-based compensation expense recorded to exploration.
(2) Derivative settlement gain (loss) is reported net of the change in accrued settlements between periods in the derivative cash settlements line item on the condensed consolidated statements of cash flows within net cash provided by operating activities. Natural gas derivative settlements for the three and six months ended June 30, 2015, include a $15.3 million gain on the early settlement of future contracts as a result of divesting our Mid-Continent assets during the second quarter of 2015.

Cautionary Information about Forward-Looking Statements

This report contains “forward-looking statements” within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. 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 expressions are intended to identify forward-lo 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 under Risk Factors in Part I, Item 1A of our 2014 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;
- 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 required to develop and/or 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 outside operated properties;
- 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 acquisitions, 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 we receive for oil, gas, and NGL sales;
- the inability of one or more of our service providers, customers, or contractual counterparties to meet their obligations;
- our ability to deliver necessary quantities of natural gas or crude oil 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 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 and other applicable 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;

- the possibility we may face unforeseen difficulties or expenses related to our implementation of a new enterprise resource planning software system (“ERP”); 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 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 Interest Rate Risk and Commodity Price Risk in Item 2 above and is incorporated herein by reference. Please also refer to the information under Interest Rate Risk and Commodity Price Risk in Management’s Discussion and Analysis of Financial Condition and Results of Operations in Part II, Item 7 of our 2014 Form 10-K.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that is 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

Effective January 1, 2015, we implemented a new ERP that materially impacted our internal control over financial reporting. In connection with this ERP implementation, we updated our internal control over financial reporting, as necessary, to accommodate modifications to our business processes and accounting procedures. The ERP implementation has not had an adverse impact on our internal control over financial reporting, nor do we expect it to have an adverse impact in future periods.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

There have been no material changes to the legal proceedings as previously disclosed in our 2014 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 2014 Form 10-K.

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, 2015, 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)]
04/01/15 - 04/30/15	—	$—	—	3,072,184
05/01/15 - 05/31/15	98	56.22	—	3,072,184
06/01/15 - 06/30/15	—	—	—	3,072,184
Total:	98	$56.22	—	3,072,184

(1) All shares purchased in the second quarter of 2015 were to offset tax withholding obligations that occurred 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 up to 6,000,000 shares 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 under the terms of 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.

ITEM 6. EXHIBITS

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

Exhibit	Description
1.1	Underwriting Agreement dated May 7, 2015, among SM Energy Company, and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner, & Smith Incorporated and J.P. Morgan Securities LLC, as representatives of the several underwriters (filed as Exhibit 1.1 to the registrant's Current Report on Form 8-K filed on May 8, 2015, and incorporated herein by reference)
3.1	Restated Certificate of Incorporation of SM Energy Company, as amended through June 1, 2010 (filed as Exhibit 3.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, and incorporated herein by reference)
3.2	Amended and Restated Bylaws of SM Energy Company effective as of December 16, 2014 (filed as Exhibit 3.1 to the registrant's Current Report on Form 8-K filed on December 19, 2014, and incorporated herein by reference)
4.1	Indenture related to senior debt securities of SM Energy Company by and between SM Energy Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the registrant's Registration Statement on Form S-3 filed on May 7, 2015 (Registration No. 333-203936) and incorporated herein by reference)
4.2	2025 Notes Supplemental Indenture (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on May 21, 2015, and incorporated herein by reference)
4.3	2019 Notes Supplemental Indenture (filed as Exhibit 4.3 to the registrant's Current Report on Form 8-K filed on May 21, 2015 and incorporated herein by reference)
10.1	Third Amendment to Fifth Amended and Restated Credit Agreement, dated May 20, 2015, among SM Energy Company, 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 May 27, 2015, and incorporated herein by reference)
12.1*	Computation of Ratio of Earnings to Fixed Charges
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.

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 29, 2015	By: /s/ JAVAN D. OTTOSON Javan D. Ottoson President and Chief Executive Officer (Principal Executive Officer)
July 29, 2015	By: /s/ A. WADE PURSELL A. Wade Pursell Executive Vice President and Chief Financial Officer (Principal Financial Officer)
July 29, 2015	By: /s/ MARK T. SOLOMON Mark T. Solomon Vice President - Controller and Assistant Secretary (Principal Accounting Officer)