SM Energy Co
Form 10-Q
August 03, 2016

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, 2016
Commission File Number 001-31539
SM ENERGY COMPANY
(Exact name of registrant as specified in its charter)

Delaware	41-0518430
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1775 Sherman Street, Suite 1200, Denver, Colorado	80203
(Address of principal executive offices)	(Zip Code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes 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 27, 2016, the registrant had 68,466,823 shares of common stock, $0.01 par value, outstanding.

SM ENERGY COMPANY
TABLE OF CONTENTS

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

	June 30, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 18	$ 18
Accounts receivable	143,979	134,124
Derivative asset	145,576	367,710
Prepaid expenses and other	14,901	17,137
Total current assets	304,474	518,989
Property and equipment (successful efforts method):		
Proved oil and gas properties	7,249,808	7,606,405
Less - accumulated depletion, depreciation, and amortization	(3,606,829)	(3,481,836)
Unproved oil and gas properties	222,967	284,538
Wells in progress	415,973	387,432
Oil and gas properties held for sale, net	173,001	641
Other property and equipment, net of accumulated depreciation of $38,175 and $32,956, respectively	146,412	153,100
Total property and equipment, net	4,601,332	4,950,280
Noncurrent assets:		
Derivative asset	113,119	120,701
Other noncurrent assets	25,550	31,673
Total other noncurrent assets	138,669	152,374
Total Assets	$ 5,044,475	$ 5,621,643
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 257,349	$ 302,517
Derivative liability	63,492	8
Total current liabilities	320,841	302,525
Noncurrent liabilities:		
Revolving credit facility	330,500	202,000
Senior Notes, net of unamortized deferred financing costs (note 5)	2,272,580	2,315,970
Asset retirement obligation	108,331	137,284
Asset retirement obligation associated with oil and gas properties held for sale	32,055	241
Net Profits Plan liability	9,476	7,611
Deferred income taxes	472,355	758,279
Derivative liability	104,660	—
Other noncurrent liabilities	44,841	45,332
Total noncurrent liabilities	3,374,798	3,466,717
Commitments and contingencies (note 6)		

Stockholders' equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued and outstanding: 68,274,551 and 68,075,700, respectively	683	681
Additional paid-in capital	321,841	305,607
Retained earnings	1,040,219	1,559,515
Accumulated other comprehensive loss	(13,907)	(13,402)
Total stockholders' equity	1,348,836	1,852,401
Total Liabilities and Stockholders' Equity	$ 5,044,475	$ 5,621,643

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

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,	
	2016	2015	2016	2015
Operating revenues:				
Oil, gas, and NGL production revenue	$291,142	$441,256	$502,965	$834,571
Net gain (loss) on divestiture activity (note 3)	50,046	71,884	(18,975)	36,082
Other operating revenues	626	3,006	900	11,427
Total operating revenues and other income	341,814	516,146	484,890	882,080
Operating expenses:				
Oil, gas, and NGL production expense	148,591	173,685	293,134	369,836
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	211,020	219,704	425,227	437,105
Exploration	13,187	25,541	28,460	62,948
Impairment of proved properties	—	12,914	269,785	68,440
Abandonment and impairment of unproved properties	38	5,819	2,349	17,446
General and administrative	28,200	42,605	60,438	86,244
Change in Net Profits Plan liability	3,125	(4,476)	1,865	(8,810)
Derivative (gain) loss	163,351	80,929	149,123	(73,238)
Other operating expenses	4,851	10,304	11,783	27,423
Total operating expenses	572,363	567,025	1,242,164	987,394
Loss from operations	(230,549)	(50,879)	(757,274)	(105,314)
Non-operating income (expense):				
Interest income	5	25	11	596
Interest expense	(34,035)	(30,779)	(65,123)	(63,426)
Gain (loss) on extinguishment of debt	—	(16,578)	15,722	(16,578)
Loss before income taxes	(264,579)	(98,211)	(806,664)	(184,722)
Income tax benefit	95,898	40,703	290,773	74,156
Net loss	$(168,681)	$(57,508)	$(515,891)	$(110,566)
Basic weighted-average common shares outstanding	68,102	67,483	68,090	67,473
Diluted weighted-average common shares outstanding	68,102	67,483	68,090	67,473
Basic net loss per common share	$(2.48)	$(0.85)	$(7.58)	$(1.64)
Diluted net loss per common share	$(2.48)	$(0.85)	$(7.58)	$(1.64)
Dividends per common share	$—	$—	$0.05	$0.05

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

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,	
	2016	2015	2016	2015
Net loss	$(168,681)	$(57,508)	$(515,891)	$(110,566)
Other comprehensive loss, net of tax:				
Pension liability adjustment	(269)	(576)	(505)	(752)
Total other comprehensive loss, net of tax	(269)	(576)	(505)	(752)
Total comprehensive loss	$(168,950)	$(58,084)	$(516,396)	$(111,318)

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,	
	2016	2015
Cash flows from operating activities:		
Net loss	$(515,891)	$(110,566)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Net (gain) loss on divestiture activity	18,975	(36,082)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	425,227	437,105
Exploratory dry hole expense	(24)	22,896
Impairment of proved properties	269,785	68,440
Abandonment and impairment of unproved properties	2,349	17,446
Stock-based compensation expense	13,915	13,215
Change in Net Profits Plan liability	1,865	(8,810)
Derivative (gain) loss	149,123	(73,238)
Derivative settlement gain	248,738	274,024
Amortization of deferred financing costs	1,930	3,892
Non-cash (gain) loss on extinguishment of debt, net	(15,722)	4,123
Deferred income taxes	(291,014)	(84,556)
Plugging and abandonment	(2,716)	(3,386)
Other, net	676	(434)
Changes in current assets and liabilities:		
Accounts receivable	(11,220)	38,951
Prepaid expenses and other	8,487	2,933
Accounts payable and accrued expenses	(61,727)	(34,040)
Accrued derivative settlements	14,117	17,595
Net cash provided by operating activities	256,873	549,508
Cash flows from investing activities:		
Net proceeds from the sale of oil and gas properties	12,967	334,988
Capital expenditures	(345,570)	(974,130)
Acquisition of proved and unproved oil and gas properties	(17,751)	(6,588)
Other, net	(900)	(996)
Net cash used in investing activities	(351,254)	(646,726)
Cash flows from financing activities:		
Proceeds from credit facility	585,000	1,230,500
Repayment of credit facility	(456,500)	(1,274,500)
Debt issuance costs related to credit facility	(3,132)	—
Net proceeds from Senior Notes	—	491,557
Cash paid to repurchase Senior Notes	(29,904)	(350,000)
Proceeds from sale of common stock	2,354	3,157
Dividends paid	(3,404)	(3,373)
Other, net	(33)	(161)
Net cash provided by financing activities	94,381	97,180
Net change in cash and cash equivalents	—	(38)

Cash and cash equivalents at beginning of period	18	120
Cash and cash equivalents at end of period	$18	$82

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 activities:

	For the Six Months Ended June 30,	
	2016	2015
	(in thousands)	
Cash paid for interest, net of capitalized interest	$63,590	$64,899
Net cash (refunded) paid for income taxes	$(4,564)	$380

As of June 30, 2016, and 2015, $106.7 million and $164.9 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 net cash used in investing activities in the periods during which the payables are settled.

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

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

Note 1 - The Company and Business

SM Energy Company ("SM Energy" or the "Company") is an independent energy company engaged in the acquisition, exploration, development, and production of crude oil and condensate, natural gas, and natural gas liquids (also respectively referred to as "oil," "gas," and "NGLs" throughout this report) in onshore North America.

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

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements include the accounts of SM Energy and its wholly-owned subsidiaries and have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") for interim financial information and the instructions to Quarterly Report on Form 10-Q and Regulation S-X. These financial statements do not include all information and notes required by GAAP for annual 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, 2015 (the "2015 Form 10-K"). In the opinion of management, all adjustments, consisting of normal recurring adjustments 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 the Company's unaudited condensed consolidated financial statements, the Company evaluated events subsequent to the balance sheet date of June 30, 2016, through the filing date of this report. Certain prior period amounts have been reclassified to conform to the current period presentation on the accompanying condensed consolidated 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 2015 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 2015 Form 10-K.

Recently Issued Accounting Standards

Effective January 1, 2016, the Company adopted, on a retrospective basis, Financial Accounting Standards Board ("FASB") Accounting Standards Update ("ASU") No. 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis. This ASU clarifies the consolidation reporting guidance in GAAP. There was no impact to the Company's financial statements or disclosures from the adoption of this standard.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), which changes the accounting for leases. This guidance is to be applied using a modified retrospective method and is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2018. Early adoption is permitted. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company's financial statements and disclosures.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("ASU 2014-09") for the recognition of revenue from contracts with customers. Subsequent to the issuance of this ASU, the

FASB has issued additional related ASUs as follows:

- In August 2015, the FASB issued ASU No. 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date. This ASU deferred the effective date of ASU 2014-09 by one year.
- In March 2016, the FASB issued ASU No. 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net). This ASU amends the principal versus agent guidance in ASU No. 2014-09.
- In April 2016, the FASB issued ASU No. 2016-10, Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing. This ASU amends the identification of performance obligations and accounting for licenses in ASU 2014-09.

• In May 2016, the FASB issued ASU No. 2016-12, Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients. This ASU amends certain issues in ASU 2014-09 on transition, collectibility, noncash consideration, and the presentation of sales taxes and other similar taxes.

ASU 2014-09 and each update have the same effective date and transition requirements. That is, the guidance under these standards is to be applied using a full retrospective method or a modified retrospective method, as outlined in ASU 2014-09, and is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2017. Early adoption is permitted only for annual periods, and interim periods within those annual periods, beginning after December 15, 2016. The Company is currently evaluating the level of effort needed to implement the standards, evaluating the provisions of each of these standards, and assessing their impact on the Company's financial statements and disclosures, as well as determining whether to use the full retrospective method or the modified retrospective method.

In March 2016, the FASB issued ASU No. 2016-09, Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting. This ASU makes targeted amendments to the accounting for employee share-based payments. This guidance is to be applied using various transition methods, such as full retrospective, modified retrospective, and prospective, based on the criteria for the specific amendments as outlined in the guidance. The guidance is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2016. Early adoption is permitted, as long as all of the amendments are adopted in the same period. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company's financial statements and disclosures.

Other than as disclosed above or in the 2015 Form 10-K, there are no other accounting standards applicable to the Company that would have a material effect on the Company's financial statements and related disclosures that have been issued but not yet adopted by the Company as of June 30, 2016, and through the filing date of this report.

Note 3 – Assets Held for Sale and Divestitures
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 changes to the fair value less estimated costs to sell impact the measurement of assets held for sale with any gain or loss reflected in the net gain (loss) on divestiture activity line item in the accompanying condensed consolidated statements of operations ("accompanying statements of operations").

As of June 30, 2016, the accompanying condensed consolidated balance sheets ("accompanying balance sheets") present $173.0 million of assets held for sale, net of accumulated depletion, depreciation, and amortization expense, which consists of certain non-core assets in each of the Company's operating regions. A corresponding aggregate asset retirement obligation liability of $32.1 million is separately presented. Certain of these assets were written down by $68.3 million to reflect fair value less estimated costs to sell upon reclassification to assets held for sale, as of March 31, 2016. During the second quarter of 2016, the Company estimated an increase in the fair value of certain previously impaired assets held for sale due to an increase in estimated selling prices, as evidenced by recent bid prices received from third parties, resulting in a $49.5 million gain recorded for the three months ended June 30, 2016. The Company expects to close the asset sale transactions prior to December 31, 2016. There were no material assets held for sale as of December 31, 2015.

Subsequent to June 30, 2016, the Company entered into separate purchase and sale agreements for the sale of certain of its Permian and Rocky Mountain assets that were classified as held for sale as of June 30, 2016. The Company expects to close these transactions prior to December 31, 2016. The closings of these transactions are subject to the satisfaction of customary closing conditions, and there can be no assurance that these transactions will close on the expected closing dates or at all.

Divestitures

During the second quarter of 2015, the Company divested its Mid-Continent assets in separate packages for total cash proceeds received at closing of $316.5 million and recorded an estimated net gain of $107.8 million for the six months ended June 30, 2015. 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 their fair value less estimated costs to sell. This write-down is reflected in the total net gain of $107.8 million discussed above. In conjunction with this divestiture, the Company closed its Tulsa, Oklahoma office in 2015 and incurred $5.0 million and $8.5 million of exit and disposal costs for the three and six months ended

June 30, 2015, respectively. Offsetting the net gain recorded on the divestiture of the Company's Mid-Continent assets were write-downs recorded during the three months ended June 30, 2015, on certain other assets held for sale totaling $66.0 million.

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

Note 4 - Income Taxes

The income tax benefit recorded for the three and six months ended June 30, 2016, and 2015, differs from the amounts that would be provided by applying the statutory United States federal income tax rate to income or loss before income taxes primarily due to the effect of state income taxes, changes in valuation allowances, research and development ("R&D") credits, and other permanent differences. The quarterly rate can also be affected by the proportional effects of forecasted net income or loss as of each period end presented.

The provision for income taxes consists of the following:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)			
Current portion of income tax expense (benefit):				
Federal	$—	$—	$—	$—
State	77	10,126	241	10,400
Deferred portion of income tax benefit	(95,975)	(50,829)	(291,014)	(84,556)
Total income tax benefit	$(95,898)	$(40,703)	$(290,773)	$(74,156)
Effective tax rate	36.2 %	41.4 %	36.0 %	40.1 %

On a year-to-date basis, a change in the Company's effective tax rate between reported periods will generally reflect differences in its estimated highest marginal state tax rate due to changes in the composition of income or loss from various state tax jurisdictions. Cumulative effects of state rate changes are reflected in the period legislation is enacted.

The Company is generally no longer subject to United States federal or state income tax examinations by tax authorities for years before 2012. During the first quarter of 2016, the Company received an expected $4.9 million refund of tax and interest after the Company and the Internal Revenue Service ("IRS") reached a final agreement on the examination of the Company's 2007 - 2011 tax years. There were no material adjustments to previously reported amounts. During the quarter ended September 30, 2015, the IRS initiated an audit of the tax partnership between the Company and Mitsui E&P Texas LP for the 2013 tax year. The Company has a significant investment in the underlying assets of this tax partnership. The Company received notice during the first quarter of 2016 that the IRS concluded the audit with no adjustments.

Note 5 - Long-Term Debt

Revolving Credit Facility

On April 8, 2016, the Company entered into a Sixth Amendment to the Fifth Amended and Restated Credit Agreement (the "Credit Agreement" and as amended, the "Amended Credit Agreement") with its lenders. The Company incurred approximately $3.1 million in deferred financing costs associated with the amendment of this credit facility. The Amended Credit Agreement provides for a maximum loan amount of $2.5 billion and has a maturity date of

December 10, 2019. Pursuant to the amendment, and as part of the regular, semi-annual borrowing base redetermination process, the Company's borrowing base was reduced to $1.25 billion. This expected reduction was primarily due to the decline in commodity prices, which had resulted in a decrease in the Company's proved reserves as of December 31, 2015. The next scheduled redetermination date is October 1, 2016. The borrowing base redetermination process considers the value of both the Company's (a) proved oil and gas properties reflected in the Company's most recent reserve report and (b) commodity derivative contracts, each as determined by the Company's lender group. The amendment also reduced the aggregate lender commitments to $1.25 billion, and changed the required percentage of oil and gas properties subject to a mortgage to at least 90 percent of the total PV-9 of the Company's proved oil and gas properties evaluated in the most recent reserve report. Further, the amendment revised certain of the Company's covenants under the Credit Agreement and modified the borrowing base utilization grid, as discussed below.

The Company must comply with certain financial and non-financial covenants under the terms of the Amended Credit Agreement, including covenants limiting dividend payments and requiring the Company to maintain certain financial ratios, as defined by the Amended Credit Agreement. Financial covenants under the Amended Credit Agreement require, as of the last day of each of the Company's fiscal quarters, the Company's (a) ratio of senior secured debt to 12-month trailing adjusted EBITDAX to be not more than 2.75 to 1.0; (b) adjusted current ratio to be not less than 1.0 to 1.0; and (c) ratio of 12-month trailing adjusted EBITDAX to interest expense to be not less than 2.0 to 1.0. The Company was in compliance with all financial and non-financial covenants under the Amended Credit Agreement as of June 30, 2016, and through the filing date of this report.

Interest and commitment fees are accrued based on a borrowing base utilization grid set forth in the Amended Credit Agreement. Eurodollar loans accrue interest at the London Interbank Offered Rate plus the applicable margin from the utilization table below, and Alternate Base Rate ("ABR") and swingline loans accrue interest at prime plus the applicable margin from the utilization table below. Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the accompanying statements of operations. Effective as of April 8, 2016, the revised borrowing base utilization grid under the Amended Credit Agreement is as follows:

Borrowing Base Utilization Grid

Borrowing Base Utilization Percentage	<25%	≥25% <50%	≥50% <75%	≥75% <90%	≥90%
Eurodollar Loans	1.750 %	2.000 %	2.250 %	2.500 %	2.750 %
ABR Loans or Swingline Loans	0.750 %	1.000 %	1.250 %	1.500 %	1.750 %
Commitment Fee Rate	0.300 %	0.300 %	0.350 %	0.375 %	0.375 %

The following table presents the outstanding balance, total amount of letters of credit outstanding, and available borrowing capacity under the Amended Credit Agreement as of July 27, 2016, and June 30, 2016, and under the Credit Agreement as of December 31, 2015:

	As of July 27, 2016	As of June 30, 2016	As of December 31, 2015
	(in thousands)		
Credit facility balance [(1)]	$330,000	$330,500	$202,000
Letters of credit [(2)]	$200	$200	$200
Available borrowing capacity	$919,800	$919,300	$1,297,800

(1) Deferred financing costs attributable to the credit facility are presented as a component of other noncurrent assets on the accompanying balance sheets and thus are not deducted from the credit facility balance.
(2) Letters of credit outstanding reduce the amount available under the credit facility on a dollar-for-dollar basis.

Senior Notes

The Company's Senior Notes consist of 6.50% Senior Notes due 2021, 6.125% Senior Notes due 2022, 6.50% Senior Notes due 2023, 5.0% Senior Notes due 2024, and 5.625% Senior Notes due 2025 (collectively referred to as "Senior Notes"). The Senior Notes, net of unamortized deferred financing costs line on the accompanying balance sheets as of June 30, 2016, and December 31, 2015, consisted of the following:

	As of June 30, 2016			As of December 31, 2015		
	Senior Notes	Unamortized Deferred Financing Costs	Senior Notes, Net of Unamortized Deferred Financing Costs	Senior Notes	Unamortized Deferred Financing Costs	Senior Notes, Net of Unamortized Deferred Financing Costs
	(in thousands)					
6.50% Senior Notes due 2021	$346,955	$ 3,721	$ 343,234	$350,000	$ 4,106	$ 345,894
6.125% Senior Notes due 2022	561,796	7,569	554,227	600,000	8,714	591,286
6.50% Senior Notes due 2023	394,985	4,801	390,184	400,000	5,231	394,769
5.0% Senior Notes due 2024	500,000	6,994	493,006	500,000	7,455	492,545
5.625% Senior Notes due 2025	500,000	8,071	491,929	500,000	8,524	491,476
Total	$2,303,736	$ 31,156	$ 2,272,580	$2,350,000	$ 34,030	$ 2,315,970

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 indentures governing the Senior Notes that limit the Company's ability to incur additional indebtedness, issue preferred stock, and make restricted payments, including dividends; however, the first $6.5 million of dividends paid each year are not restricted by the restricted payment covenant. The Company was in compliance with all covenants under its Senior Notes as of June 30, 2016, and through the filing date of this report. The Company may redeem some or all of its Senior Notes prior to their maturity at redemption prices based on a premium plus accrued and unpaid interest as described in the indentures governing the Senior Notes.

During the first quarter of 2016, the Company repurchased in open market transactions a total of $46.3 million in aggregate principal amount of its 6.50% Senior Notes due 2021, 6.125% Senior Notes due 2022, and 6.50% Senior Notes due 2023 for a settlement amount of $29.9 million, excluding interest. Of the $29.9 million settlement amount, $10.0 million related to purchases during the first quarter of 2016, in which the related cash settlement occurred during the three months ended June 30, 2016. The Company recorded a net gain on extinguishment of debt of approximately $15.7 million for the six months ended June 30, 2016. This amount includes a gain of $16.4 million associated with the discount realized upon repurchase, which was partially offset by approximately $700,000 related to the acceleration of unamortized deferred financing costs. The Company accounted for the repurchases under the extinguishment method of accounting. The Company canceled all repurchased notes upon cash settlement.

Note 6 - Commitments and Contingencies

Commitments

There were no material changes in commitments during the first half of 2016, except as discussed below. Please refer to Note 6 - Commitments and Contingencies in the Company's 2015 Form 10-K for additional discussion.

During the second quarter of 2016, the Company entered into a water disposal agreement. Under the agreement, the Company is committed to deliver 25.4 MMBbl of water for treatment through 2026. In the event that the Company does not deliver any volumes under this agreement, the Company's aggregate undiscounted deficiency payments would be approximately $23.0 million. This commitment will not be effective until the counterparty constructs and places the associated pipeline into operation, which is expected to be by the end of 2016.

During the first half of 2016, the Company renegotiated the terms of certain drilling rig contracts to provide flexibility concerning the timing of activity and payment. For the three and six months ended June 30, 2016, the Company incurred $2.6 million and $7.6 million, respectively, of expense related to the early termination of drilling rig contracts or fees incurred for rigs placed on standby, which are recorded in the other operating expenses line item in the accompanying statements of operations. 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.

During the first quarter of 2016, the Company entered into amendments to certain oil gathering and gas gathering agreements related to its outside-operated Eagle Ford shale assets, neither of which previously had a minimum volume commitment, in order to obtain more favorable rates and terms. Under these amended agreements, as of June 30, 2016, the Company is now committed to deliver 296 Bcf of natural gas and 39 MMBbl of oil through 2034. In the event that the Company delivers no product under these amended agreements, the Company's aggregate undiscounted deficiency payments would be approximately $342.0 million at June 30, 2016; however, because of the Company's partial ownership interest in the gathering systems used to provide the services under these agreements, the Company is entitled to receive its share of operating income generated by the systems, and thus would expect to receive approximately $241.4 million if the $342.0 million shortfall payment was required.

During the first quarter of 2016, the Company entered into an amendment to a gas gathering agreement related to its operated Eagle Ford shale assets, which reduced the Company's volume commitment amount as of December 31, 2015, by 829 Bcf, and reduced the aggregate undiscounted deficiency payments, in the event no product is delivered, by $118.2 million through 2021.

As of June 30, 2016, the Company had total gas, oil, and NGL gathering, processing, and transportation throughput commitments with various third parties that require delivery of a minimum amount of 1,590 Bcf of natural gas, 72 MMBbl of crude oil, and 14 MMBbl of natural gas liquids through 2034. If the Company delivers no product, the aggregate undiscounted deficiency payments total approximately $1.0 billion through 2034, prior to considering the $241.4 million of operating income the Company would expect to receive if certain payments were required as discussed above.

As of the filing date of this report, the Company does not expect to incur any material shortfalls with regard to its gas, oil, and NGL gathering, processing, and transportation throughput commitments.

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 the amount can be reasonably estimated. 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. As of June 30, 2016, the Company had $4.4 million accrued for estimated exposure related to potential claims for payment of royalties on certain Federal and Indian oil and gas leases. Although the Company believes that it has properly estimated its potential exposure with respect to these claims based on various contracts, laws and regulations, administrative rulings, and interpretations thereof, adjustments could be required as new interpretations and regulations arise.

Note 7 - Compensation Plans

Equity Incentive Compensation Plan

As of June 30, 2016, 6.2 million shares of common stock remained available for grant under the Equity Incentive Compensation Plan.

Performance Share Units Under the Equity Incentive Compensation Plan

The Company grants performance share units ("PSUs") to eligible employees as part of its long-term 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. Compensation expense for PSUs is recognized within general and administrative and exploration expense over the vesting periods of the respective awards.

Total compensation expense recorded for PSUs for the three months ended June 30, 2016, and 2015, was $3.0 million and $2.7 million, respectively, and $5.9 million and $5.0 million for the six months ended June 30, 2016, and 2015, respectively. As of June 30, 2016, there was $12.3 million of total unrecognized compensation expense related to unvested PSU awards, which is being amortized through 2018. There were no material changes to the outstanding and non-vested PSUs during the six months ended June 30, 2016.

Subsequent to June 30, 2016, as part of its regular annual long-term equity compensation program, the Company granted 447,971 PSUs with a fair value of $11.9 million. These PSUs will fully vest on the third anniversary of the date of the grant. Also, subsequent to June 30, 2016, the Company settled PSUs that were granted in 2013, which earned a 0.2 times multiplier, by issuing a net 30,061 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, 14,809 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 long-term equity compensation program. Each RSU represents a right to receive one share of the Company's common stock upon settlement of the award at the end of the specified vesting period. Compensation expense for RSUs is recognized within general and administrative expense and exploration expense over the vesting periods of the award.

Total compensation expense recorded for RSUs was $3.3 million and $2.9 million for the three months ended June 30, 2016, and 2015, respectively, and $6.5 million and $5.8 million for the six months ended June 30, 2016, and 2015, respectively. As of June 30, 2016, there was $12.0 million of total unrecognized compensation expense related to unvested RSU awards, which is being amortized through 2018. There were no material changes to the outstanding and non-vested RSUs during the six months ended June 30, 2016.

Subsequent to June 30, 2016, as part of its regular annual long-term equity compensation program, the Company granted 417,065 RSUs with a fair value of $11.7 million. These RSUs will vest one-third of the total grant on each of the next three anniversary dates of the grant. Also, subsequent to June 30, 2016, the Company settled 232,258 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 162,211 net shares of common stock. The remaining 70,047 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 2016 and 2015, the Company issued 53,473 and 37,950 shares, respectively, of its common stock to its non-employee directors, under the Company's Equity Incentive Compensation Plan and recorded $517,000 and $1.2 million, respectively, of compensation expense.

Beginning with 2016, all shares issued to non-employee directors fully vest on December 31st of the year granted.

Employee Stock Purchase Plan

Under the Company's Employee Stock Purchase Plan ("ESPP"), eligible employees may purchase shares of the Company's common stock through payroll deductions of up to 15 percent of eligible compensation, without accruing in excess of $25,000 in value from purchases for each calendar year. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on the first or last day of the purchase period, and shares issued under the ESPP have no restriction period. The ESPP is intended to qualify under Section 423 of the Internal Revenue Code ("IRC"). The Company had 808,854 shares available for issuance under the ESPP as of June 30, 2016. There were 140,853 and 96,285 shares issued under the ESPP during the second quarters of 2016, and 2015, respectively. The fair value of ESPP grants is measured at the date of grant using the Black-Scholes option-pricing model.

Note 8 - Pension Benefits

Pension Plans

The Company has a non-contributory defined benefit pension plan covering substantially all of its employees who joined the Company prior to January 1, 2015, and 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"). The Company froze the Pension Plans to new participants, effective as of December 31, 2015. Employees participating in the Pension Plans as of December 31, 2015, will continue to earn benefits.

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,	
	2016	2015	2016	2015
	(in thousands)			
Service cost	$2,113	$2,390	$4,100	$3,974
Interest cost	830	700	1,454	1,248
Expected return on plan assets that reduces periodic pension cost	(573)	(597)	(1,118)	(1,091)
Amortization of prior service cost	5	5	9	9
Amortization of net actuarial loss	419	571	791	743
Net periodic benefit cost	$2,794	$3,069	$5,236	$4,883

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 $6.0 million to the Pension Plans during the six months ended June 30, 2016.

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 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 and contingent PSUs. The treasury stock method is used to measure the dilutive impact of these stock awards.

PSUs represent the right to receive, upon settlement of the PSUs after the completion of the three-year performance period, a number of shares of the Company's common stock that may range from zero to two times the number of PSUs granted on the award date. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, that would be issuable at the end of the respective reporting period, assuming that date was the end of the contingency period applicable to such PSUs.

Please refer to Note 7 - Compensation Plans for additional discussion of the RSUs and PSUs granted subsequent to June 30, 2016, as part of the Company's regular annual long-term equity compensation program, in addition to the net RSUs and PSUs settled.

When the Company recognizes a loss from continuing operations, as was the case for the three and six months ended June 30, 2016, and 2015, all potentially dilutive shares are anti-dilutive and are consequently excluded from the calculation of diluted net loss per common share. The following table details the weighted-average anti-dilutive securities related to RSUs and PSUs for the periods presented:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)			
Anti-dilutive	155	590	70	490

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,	
	2016	2015	2016	2015
	(in thousands, except per share amounts)			
Net loss	$(168,681)	$(57,508)	$(515,891)	$(110,566)
Basic weighted-average common shares outstanding	68,102	67,483	68,090	67,473
Add: dilutive effect of unvested RSUs and contingent PSUs	—	—	—	—
Diluted weighted-average common shares outstanding	68,102	67,483	68,090	67,473
Basic net loss per common share	$(2.48)	$(0.85)	$(7.58)	$(1.64)
Diluted net loss per common share	$(2.48)	$(0.85)	$(7.58)	$(1.64)

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 consist of swap and collar arrangements for oil, gas, and NGLs. 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 arrangements, the Company receives the difference between an agreed upon index and the floor price if the index price is below the floor price. The Company pays the difference between the agreed upon ceiling price and the index price if the index price is above the ceiling price. No amounts are paid or received if the index price is between the floor and ceiling prices.

As of June 30, 2016, the Company had commodity derivative contracts outstanding through the second quarter of 2020 as summarized in the tables below. During the three months ended March 31, 2016, the Company restructured certain of its gas derivative contracts by buying fixed price volumes to offset existing 2018 and 2019 fixed price swap contracts totaling 55.0 million MMBtu. The Company then entered into new 2017 fixed price swap contracts totaling 38.6 million MMBtu with a contract price of $4.43 per MMBtu. No cash or other consideration was included as part of the restructuring.

Subsequent to June 30, 2016, the Company entered into derivative fixed price swap contracts through the first quarter of 2018 for a total of 15.6 million MMBtu of gas production at contract prices ranging from $2.90 to $3.24 per MMBtu, and derivative fixed price swap contracts through the fourth quarter of 2018 for 1.4 million Bbls of NGL production at contract prices ranging from

$21.32 per Bbl to $21.79 per Bbl. Additionally, subsequent to June 30, 2016, the Company entered into a derivative collar contract through the fourth quarter of 2017 for a total of 1.4 million Bbls of crude oil production with a contract floor price of $45.00 per Bbl and a contract ceiling price of $56.25 per Bbl.

The following tables summarize the approximate volumes and average contract prices of contracts the Company had in place as of June 30, 2016:

Oil Swaps

Contract Period	NYMEX WTI Volumes	Weighted-Average Contract Price
	(MBbls)	(per Bbl)
Third quarter 2016	1,840	$ 71.80
Fourth quarter 2016	1,399	$ 67.73
2017	3,053	$ 45.61
All oil swaps	6,292	

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(MBbls)	(per Bbl)	(per Bbl)
Third quarter 2016	672	$ 40.00	$ 51.57
Fourth quarter 2016	881	$ 40.00	$ 51.52
2017	1,018	$ 45.00	$ 51.02
All oil collars	2,571		

Natural Gas Swaps

Contract Period	Sold Volumes	Weighted-Average Contract Price	Purchased Volumes	Weighted-Average Contract Price	Net Volumes
	(BBtu)	(per MMBtu)	(BBtu)	(per MMBtu)	(BBtu)
Third quarter 2016	25,724	$ 3.13	—	$ —	25,724
Fourth quarter 2016	26,700	$ 3.34	—	$ —	26,700
2017	88,894	$ 4.04	—	$ —	88,894
2018	53,048	$ 3.75	(30,606)	$ 4.27	22,442
2019	24,415	$ 4.34	(24,415)	$ 4.34	—
All gas swaps*	218,781		(55,021)		163,760

*Total net volumes of natural gas swaps are comprised of IF El Paso Permian (2%), IF HSC (97%), and IF NNG Ventura (1%).

NGL Swaps

Contract Period	OPIS Purity Ethane Mont Belvieu		OPIS Propane Mont Belvieu Non-TET		OPIS Normal Butane Mont Belvieu Non-TET		OPS Isobutane Mont Belvieu Non-TET	
	Volumes (MBbls)	Weighted-Average Contract Price (per Bbl)	Volumes (MBbls)	Weighted-Average Contract Price (per Bbl)	Volumes (MBbls)	Weighted-Average Contract Price (per Bbl)	Volumes (MBbls)	Weighted-Average Contract Price (per Bbl)
Third quarter 2016	751	$ 8.70	863	$ 19.03	248	$ 22.90	200	$ 23.24
Fourth quarter 2016	687	$ 8.71	792	$ 18.53	226	$ 22.91	182	$ 23.25
2017	3,062	$ 8.92	721	$ 20.01	—	$ —	—	$ —
2018	2,435	$ 10.18	—	$ —	—	$ —	—	$ —
2019	1,200	$ 10.92	—	$ —	—	$ —	—	$ —
2020	539	$ 11.13	—	$ —	—	$ —	—	$ —
Total NGL swaps	8,674		2,376		474		382	

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 $90.5 million as of June 30, 2016, and a net asset of $488.4 million as of December 31, 2015.

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

	As of June 30, 2016			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity contracts	Current assets	$145,576	Current liabilities	$63,492
Commodity contracts	Noncurrent assets	113,119	Noncurrent liabilities	104,660
Derivatives not designated as hedging instruments		$258,695		$168,152

	As of December 31, 2015			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity contracts	Current assets	$367,710	Current liabilities	$ 8
Commodity contracts	Noncurrent assets	120,701	Noncurrent liabilities	—
Derivatives not designated as hedging instruments		$488,411		$ 8

Offsetting of Derivative Assets and Liabilities

As of June 30, 2016, and December 31, 2015, all derivative instruments held by the Company were subject to master netting arrangements with 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.

18

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, 2016	December 31, 2015	Derivative Liabilities As of June 30, 2016	December 31, 2015
	(in thousands)			
Gross amounts presented in the accompanying balance sheets	$258,695	$ 488,411	$(168,152)	$ (8)
Amounts not offset in the accompanying balance sheets	(158,955)	(8)	158,955	8
Net amounts	$99,740	$ 488,403	$(9,197)	$ —

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, 2016	2015	For the Six Months Ended June 30, 2016	2015
	(in thousands)			
Derivative settlement (gain) loss:				
Oil contracts	$(72,164)	$(73,915)	$(172,156)	$(180,129)
Gas contracts [1]	(31,439)	(38,880)	(72,492)	(73,112)
NGL contracts	1,893	—	(4,090)	(20,783)
Total derivative settlement (gain) loss	$(101,710)	$(112,795)	$(248,738)	$(274,024)
Total derivative (gain) loss:				
Oil contracts	$60,773	$66,749	$50,341	$(7,111)
Gas contracts	62,489	6,070	38,466	(76,269)
NGL contracts	40,089	8,110	60,316	10,142
Total derivative (gain) loss:	$163,351	$80,929	$149,123	$(73,238)

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(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 our Mid-Continent assets during the second quarter of 2015.

Credit Related Contingent Features

As of June 30, 2016, 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 Amended Credit Agreement, as discussed above, changed the required percentage of oil and gas properties subject to a mortgage to at least 90 percent of the total PV-9 of the Company's proved oil and gas properties evaluated in the most recent reserve report.

Note 11 - Fair Value Measurements

The Company follows fair value measurement 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, 2016:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives (1)	$ —	$ 258,695	$ —
Total property and equipment, net (2)	$ —	$ —	$ 99,944
Liabilities:			
Derivatives (1)	$ —	$ 168,152	$ —
Net Profits Plan (1)	$ —	$ —	$ 9,476

(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.

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 were classified within the fair value hierarchy as of December 31, 2015:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives (1)	$ —	$ 488,411	$ —
Total property and equipment, net (2)	$ —	$ —	$ 124,813
Liabilities:			
Derivatives (1)	$ —	$ 8	$ —
Net Profits Plan (1)	$ —	$ —	$ 7,611

(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.

20

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. A discount rate of 10 percent was 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, 2016, would differ by approximately $1.5 million. A one percent increase or decrease in the discount rate would result in a change of approximately $400,000. 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, 2016 (in thousands)
Beginning balance	$ 7,611
Net increase in liability [1]	4,042
Net settlements [1] [2]	(2,177)
Transfers in (out) of Level 3	—
Ending balance	$ 9,476

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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.

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, 2016, or December 31, 2015, as they were recorded at carrying value, net of unamortized deferred financing costs. Please refer to Note 5 - Long-Term Debt for discussion of the Company's repurchase of a portion of its Senior Notes during the first quarter of 2016.

	As of June 30, 2016		As of December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
6.50% Senior Notes due 2021	$346,955	$328,091	$350,000	$262,938
6.125% Senior Notes due 2022	561,796	516,852	600,000	440,250
6.50% Senior Notes due 2023	394,985	366,349	400,000	296,000
5.0% Senior Notes due 2024	500,000	426,875	500,000	334,065
5.625% Senior Notes due 2025	500,000	433,125	500,000	326,875
Total Senior Notes	$2,303,736	$2,071,292	$2,350,000	$1,660,128

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 and Other Property and Equipment

Total property and equipment, net, measured at fair value within the accompanying balance sheets totaled $99.9 million and $124.8 million as of June 30, 2016, and December 31, 2015, respectively.

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 representative of the current operating environment, as selected by the Company’s management. The calculation of the discount rates are based on the best information available and were estimated to be 10 percent to 15 percent based on the reservoir specific weightings of future estimated proved and unproved cash flows as of June 30, 2016, and December 31, 2015. The Company believes the discount rates are representative of current market conditions and take into account estimates of future cash payments, reserve categories, 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 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 did not recognize any impairment on proved properties during the three months ended June 30, 2016. For the six months ended June 30, 2016, the Company recorded impairment of proved properties expense of $269.8 million due to the decline in proved and risk-adjusted probable and possible reserve expected cash flows for the Company's outside-operated Eagle Ford assets, driven by commodity price declines during the first quarter of 2016. The Company recorded impairment of proved oil and gas properties expense of $468.7 million for the year ended December 31, 2015, due to the decline in proved and risk-adjusted probable and possible reserve expected cash flows, driven by commodity price declines. Impairments were recorded mainly in the Company's east Texas and Powder River Basin programs with smaller impacts on other legacy and non-core assets in the Rocky Mountain region.

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. The Company recorded $38,000 and $2.3 million abandonment and impairment expense on unproved properties for the three and six months ended June 30, 2016, respectively, and $78.6 million for the year ended December 31, 2015. In all periods discussed, the abandonment and impairment expense resulted from lease expirations and acreage the Company no longer intended to develop in light of changes in drilling plans in response to the decline in commodity prices.

Other property and equipment costs are evaluated for impairment and reduced to fair value when there is an indication the carrying costs may not be recoverable. Fair value of other property and equipment is valued using an income valuation technique or market approach depending on the quality of information available to support management's assumptions and the circumstances. The valuation includes consideration of the proved and unproved assets supported by the property and equipment, future cash flows associated with the assets, and fixed costs necessary to operate and maintain the assets. The Company recorded impairment of other property and equipment expense of $49.4 million for the year ended December 31, 2015, on the Company's gathering system assets in east Texas. These assets were impaired in conjunction with the impairment of the associated proved and unproved properties, which the Company does not intend to develop during an environment of sustained low commodity prices.

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. 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. As of June 30, 2016, certain assets held for sale are recorded at fair value totaling $99.9 million less estimated selling costs. Certain of these assets were written down during the first quarter of 2016. A subsequent increase in estimated selling prices, as evidenced by recent bid prices received from third parties, resulted in a $49.5 million gain recorded for the three months ended June 30, 2016. Please refer to Note 3 – Assets Held for Sale and Divestitures. There were no assets held for sale recorded at fair value as of December 31, 2015.

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.

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

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

Overview of the Company, Highlights, and Outlook

General Overview

We are an independent energy company engaged in the acquisition, exploration, development, and production of oil, gas, and NGLs in onshore North America. Our strategic objective is to profitably 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 growth opportunities through both exploration and acquisitions, and we seek to maximize the value of our assets through industry leading technology application and outstanding operational execution. We focus on achieving high full-cycle economic returns on our investments and maintaining a simple, strong balance sheet through a conservative approach to leverage.

We currently focus our capital investments on our development positions in the Eagle Ford shale, Bakken/Three Forks, and Permian Basin resource plays. We also have a delineation and exploration program in the Powder River Basin.

In the second quarter of 2016, we had the following financial and operational results:

- Average net daily production for the three months ended June 30, 2016, was 45.1 MBbls of oil, 428.2 MMcf of gas, and 40.8 MBbls of NGLs, for a quarterly equivalent daily production rate of 157.2 MBOE, compared with 181.0 MBOE for the same period in 2015. Please see additional discussion below under Production Results.

- We recorded a net loss of $168.7 million, or $2.48 per diluted share, for the three months ended June 30, 2016, compared with a net loss of $57.5 million, or $0.85 per diluted share, for the three months ended June 30, 2015. Please refer to Comparison of Financial Results and Trends Between the Three Months and Six Months Ended June 30, 2016, and 2015, below for additional discussion regarding the components of net loss for each period.

- Costs incurred for oil and gas property acquisitions, exploration and development activities for the three months ended June 30, 2016, totaled $177.3 million, compared with $354.0 million for the same period in 2015. Please refer to Costs Incurred in Oil and Gas Producing Activities below for additional discussion.

- Net cash provided by operating activities for the three months ended June 30, 2016, totaled $138.6 million, compared with $265.6 million for the same period in 2015.

- Adjusted EBITDAX, a non-GAAP financial measure, for the three months ended June 30, 2016, was $217.1 million, compared with $337.3 million for the same period in 2015. Please refer to Non-GAAP Financial Measures below for additional discussion, including our definition of adjusted EBITDAX and reconciliations of our net 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 the calendar month average of the NYMEX WTI daily contract settlement prices, excluding weekends, during the month of production, 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 2016, as well as the second quarter of 2015:

	For the Three Months Ended		
	June 30, 2016	March 31, 2016	June 30, 2015
Crude Oil (per Bbl):			
Average NYMEX contract monthly price	$45.59	$ 33.41	$ 57.85
Realized price, before the effect of derivative settlements	$39.38	$ 25.67	$ 51.45
Oil derivative settlement gain	$17.59	$ 24.27	$ 14.53
Natural Gas:			
Average NYMEX monthly settle price (per MMBtu)	$1.95	$ 1.96	$ 2.73
Realized price, before the effect of derivative settlements (per Mcf)	$1.79	$ 1.87	$ 2.53
Natural gas derivative settlement gain (per Mcf) (1)	$0.81	$ 1.15	$ 0.88
NGLs (per Bbl):			
Average OPIS price (2)	$20.04	$ 15.99	$ 20.79
Realized price, before the effect of derivative settlements	$16.12	$ 11.76	$ 16.85
NGL derivative settlement (loss) gain	$(0.51)	$ 1.78	$ —

(1) Natural gas derivative settlements for the three 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, 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 continue to be volatile. In addition to supply and demand fundamentals, as a global commodity, the price of oil is affected by real or perceived geopolitical risks in all regions of the world as well as the relative strength of the dollar compared to other currencies. Due to short-term supply reductions and disruptions, crude oil prices gained strength during the second quarter of 2016. However, as those temporary disruptions are rectified, we expect supply to increase back to prior levels while demand for oil and oil products is expected to continue to slow during the remainder of 2016 and remain the main source of uncertainty for future prices. Although the United States is now leading production declines, declines elsewhere in the world are required to balance the market.

Supply for natural gas continued to exceed demand during the second quarter of 2016; however, demand growth from gas fired power generation and exports exceeded expectations causing an uplift in prices late in the second quarter of 2016. We expect prices to continue to recover due to decreased supply from associated oil drilling and ethane recovery, and from continued demand growth from LNG exports and exports to Mexico. We also expect prices to fluctuate with changes in demand resulting from the weather.

NGL prices have recovered in recent months due to oil and natural gas price recovery and we expect continued recovery through 2017 as increased demand from export and petrochemical markets grow. We expect that world-scale ethane crackers currently under construction will come online at the end of the year, increasing demand for propane and ethane as feedstock.

As commodity prices have seen some recovery in the second quarter of 2016, the rig count has slightly increased. Overall, we expect commodity prices to fluctuate but remain near current levels through the remainder of 2016, and we expect prices to increase in 2017 due to reduction in supply and demand increases across all 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 27, 2016, and June 30, 2016:

	As of July 27, 2016	As of June 30, 2016
NYMEX WTI oil (per Bbl)	$45.07	$50.83
NYMEX Henry Hub gas (per MMBtu)	$3.02	$3.14
OPIS NGLs (per Bbl)	$20.48	$22.73

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, the level of capital commitments and long-term obligations we have in place, and our ability to enter into favorable derivative commodity contracts. With our current derivative contracts, we believe we 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 and the caption titled Commodity Price Risk in Overview of Liquidity and Capital Resources below for additional information regarding our oil, gas, and NGL derivatives.

Second Quarter 2016 Highlights and Outlook for the Remainder of 2016

Operational Activities. Our goal during 2016 is to maintain a strong balance sheet and preserve liquidity in the current commodity price environment while improving our portfolio and holding our quality acreage positions. We expect to incur capital expenditures below adjusted EBITDAX in order to minimize any impact to our total debt. We believe this focus on our liquidity will best preserve our balance sheet and will give us the flexibility to adapt as industry conditions change.

We expect our capital program for 2016 to be approximately $670 million, of which we plan to invest approximately 85 percent in drilling and completion activities with the focus on our core development programs in the Bakken/Three Forks, Permian Basin, and Eagle Ford shale. Our capital expenditure guidance was reduced from the approximate $705 million previously announced, as lower drilling and completion costs and realized efficiencies have contributed to overall capital cost savings. We plan to continue our focus on conducting safe operations even as we pursue cost saving measures throughout our business.

In our operated Eagle Ford shale program, we began the second quarter of 2016 with one active, operated drilling rig. We expect to drop this rig during the third quarter of 2016, and plan to utilize one frac crew through the third quarter of 2016. In 2016, our capital is primarily being spent on wells that were drilled but uncompleted at year-end 2015 and to meet lease obligations. As of June 30, 2016, in our operated Eagle Ford program, we had drilled but not completed 78 gross and net wells. We drilled 13 gross and net wells during the first half of 2016.

In our outside-operated Eagle Ford shale program, the operator has further slowed its pace of development in 2016. We do not expect any additional drilling or completion activity in 2016.

In our Bakken/Three Forks program, we began the second quarter of 2016 with two active, operated drilling rigs. We dropped one drilling rig during the second quarter of 2016, and expect to run the remaining drilling rig for the remainder of 2016. As of June 30, 2016, in our operated Bakken/Three Forks program, we had drilled but not completed 40 gross wells (35 net). We drilled 15 gross wells (13 net) during the first half of 2016.

In our Permian Basin development program, we began the second quarter of 2016 with one operated drilling rig and increased to two drilling rigs during the second quarter of 2016. We are focused on developing the Wolfcamp and Spraberry shale intervals on our Sweetie Peck property in Upton County, Texas. As of June 30, 2016, in our Permian program, we had drilled but not completed eight gross and net wells. We drilled 11 gross and net wells during the first half of 2016.

We have curtailed activity in our delineation and exploration programs to focus our capital spending on our highest return development programs and to meet acreage-holding commitments in our core plays. We dropped our last operated drilling rig in our Powder River Basin program during the first quarter of 2016.

We will continue to evaluate our drilling and completion activities throughout the remainder of 2016 as we respond to commodity price changes and costs. Please refer to Overview of Liquidity and Capital Resources below for additional discussion concerning how we intend to fund the remainder of our 2016 capital program.

Production Results. The table below provides a regional breakdown of our production for the three and six months ended June 30, 2016:

	South Texas & Gulf Coast		Rocky Mountain		Permian		Total [1]	
	Three Months Ended	Six Months Ended	Three Months Ended	Six Months Ended	Three Months Ended	Six Months Ended	Three Months Ended	Six Months Ended
	June 30, 2016		June 30, 2016		June 30, 2016		June 30, 2016	
Oil (MMBbl)	1.4	2.9	2.1	4.3	0.6	1.0	4.1	8.2
Gas (Bcf)	34.9	66.9	2.7	5.3	1.4	2.4	39.0	74.7
NGLs (MMBbl)	3.6	6.9	0.1	0.2	—	—	3.7	7.1
Equivalent (MMBOE)	10.9	21.0	2.6	5.3	0.8	1.4	14.3	27.7
Avg. daily equivalents (MBOE/d)	119.3	115.3	28.6	29.4	9.3	7.7	157.2	152.4
Relative percentage	76 %	76 %	18 %	19 %	6 %	5 %	100 %	100 %

[1] Amounts may not calculate due to rounding.

Production decreased for the three and six months ended June 30, 2016, compared to the same periods in 2015, driven by the divestiture of properties in our Mid-Continent region in the second quarter of 2015, as well as a reduction in our drilling and completion activity. The table below provides a summary of wells completed in our operated programs during the three and six months ended June 30, 2016.

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2016			
	Gross	Net	Gross	Net
Eagle Ford shale	9	9	11	11
Bakken/Three Forks	17	14	22	18
Permian Basin	8	8	12	12

Please refer to Comparison of Financial Results and Trends Between the Three Months and Six Months Ended June 30, 2016, and 2015 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	For the Six Months Ended
	June 30, 2016	
	(in millions)	
Development costs [1]	$ 150.7	$ 328.9
Exploration costs	23.4	56.0
Acquisitions		

Proved properties	0.1	2.3
Unproved properties [2]	3.1	17.5
Total, including asset retirement obligations [3]	$ 177.3	$ 404.7

27

(1) Includes facility costs of $4.3 million and $12.1 million for the three and six months ended June 30, 2016, respectively.
(2) The three and six months ended June 30, 2016, includes $2.8 million and $16.8 million, respectively, of unproved properties acquired as part of proved property acquisitions. The remaining amount is leasing activity.
(3) The three and six months ended June 30, 2016, includes amounts relating to estimated asset retirement obligations of $1.2 million and $2.1 million, respectively, and capitalized interest of $5.2 million and $10.3 million, respectively.

The majority of costs incurred for oil and gas producing activities during 2016 were in the development of our Bakken/Three Forks, Permian Basin, and Eagle Ford shale programs. Please refer to Production Results above for discussion on completion activity, and to the section Second Quarter 2016 Highlights and Outlook for the Remainder of 2016 above for discussion on wells that have been drilled but not completed as of June 30, 2016. Additionally, please refer to Overview of Liquidity and Capital Resources below for additional discussion on how we expect to fund our capital expenditure program.

Subsequent Events. Subsequent to June 30, 2016, we entered into separate purchase and sale agreements for the sale of certain of our Permian and Rocky Mountain assets that were classified as held for sale at June 30, 2016. Please refer to Note - Assets Held for Sale and Divestitures in Part I, Item I of this report for additional discussion.

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, 2016	March 31, 2016	December 31, 2015	September 30, 2015
	(in millions, except for production data)			
Production (MMBOE)	14.3	13.4	14.9	16.1
Oil, gas, and NGL production revenue	$ 291.1	$ 211.8	$ 298.7	$ 366.6
Oil, gas, and NGL production expense	$ 148.6	$ 144.5	$ 169.2	$ 184.6
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$ 211.0	$ 214.2	$ 240.0	$ 243.9
Exploration	$ 13.2	$ 15.3	$ 37.9	$ 19.7
General and administrative	$ 28.2	$ 32.2	$ 33.6	$ 37.8
Net income (loss)	$ (168.7)	$ (347.2)	$ (340.3)	$ 3.1

Note: Amounts may not calculate due to rounding.

Selected Performance Metrics:

	For the Three Months Ended			
	June 30, 2016	March 31, 2016	December 31, 2015	September 30, 2015
Average net daily production equivalent (MBOE/d)	157.2	147.5	162.1	174.5
Lease operating expense (per BOE)	$ 3.31	$ 3.79	$ 3.85	$ 3.86
Transportation costs (per BOE)	$ 5.95	$ 6.06	$ 6.10	$ 6.27
Production taxes as a percent of oil, gas, and NGL production revenue	4.6 %	4.2 %	5.1 %	4.2 %
Ad valorem tax expense (per BOE)	$ 0.19	$ 0.27	$ 0.38	$ 0.40
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)	$ 14.75	$ 15.96	$ 16.10	$ 15.19
General and administrative (per BOE)	$ 1.97	$ 2.40	$ 2.26	$ 2.35

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, 2016	2015	Amount Change Between Periods	Percent Change Between Periods	For the Six Months Ended June 30, 2016	2015	Amount Change Between Periods	Percent Change Between Periods
Net production volumes [(1)]								
Oil (MMBbl)	4.1	5.1	(1.0)	(19)%	8.2	10.3	(2.1)	(20)%
Gas (Bcf)	39.0	44.2	(5.2)	(12)%	74.7	90.1	(15.5)	(17)%
NGLs (MMBbl)	3.7	4.0	(0.3)	(8)%	7.1	7.9	(0.9)	(11)%
Equivalent (MMBOE)	14.3	16.5	(2.2)	(13)%	27.7	33.3	(5.5)	(17)%
Average net daily production [(1)]								
Oil (MBbl per day)	45.1	55.9	(10.8)	(19)%	45.2	57.0	(11.8)	(21)%
Gas (MMcf per day)	428.2	485.8	(57.6)	(12)%	410.2	498.0	(87.8)	(18)%
NGLs (MBbl per day)	40.8	44.2	(3.4)	(8)%	38.8	43.8	(5.0)	(11)%
Equivalent (MBOE per day)	157.2	181.0	(23.8)	(13)%	152.4	183.7	(31.4)	(17)%
Oil, gas, and NGL production revenue (in millions)								
Oil production revenue	$161.6	$261.7	$(100.1)	(38)%	$267.4	$463.2	$(195.8)	(42)%
Gas production revenue	69.7	111.9	(42.2)	(38)%	136.4	238.7	(102.3)	(43)%
NGL production revenue	59.8	67.7	(7.9)	(12)%	99.2	132.7	(33.5)	(25)%
Total	$291.1	$441.3	$(150.2)	(34)%	$503.0	$834.6	$(331.6)	(40)%
Oil, gas, and NGL production expense (in millions)								
Lease operating expense	$47.4	$53.8	$(6.4)	(12)%	$98.2	$120.3	$(22.1)	(18)%
Transportation costs	85.1	92.9	(7.8)	(8)%	166.4	194.9	(28.5)	(15)%
Production taxes	13.3	22.9	(9.6)	(42)%	22.2	41.7	(19.5)	(47)%
Ad valorem tax expense	2.8	4.1	(1.3)	(32)%	6.3	12.9	(6.6)	(51)%
Total	$148.6	$173.7	$(25.1)	(14)%	$293.1	$369.8	$(76.7)	(21)%
Realized price (before the effect of derivative settlements)								
Oil (per Bbl)	$39.38	$51.45	$(12.07)	(23)%	$32.51	$44.92	$(12.41)	(28)%
Gas (per Mcf)	$1.79	$2.53	$(0.74)	(29)%	$1.83	$2.65	$(0.82)	(31)%
NGLs (per Bbl)	$16.12	$16.85	$(0.73)	(4)%	$14.05	$16.76	$(2.71)	(16)%
Per BOE	$20.35	$26.78	$(6.43)	(24)%	$18.14	$25.10	$(6.96)	(28)%
Per BOE Data [(1)]								
Production costs:								
Lease operating expense	$3.31	$3.26	$0.05	2%	$3.54	$3.62	$(0.08)	(2)%
Transportation costs	$5.95	$5.64	$0.31	5%	$6.00	$5.86	$0.14	2%
Production taxes	$0.93	$1.39	$(0.46)	(33)%	$0.80	$1.25	$(0.45)	(36)%
Ad valorem tax expense	$0.19	$0.25	$(0.06)	(24)%	$0.23	$0.39	$(0.16)	(41)%
General and administrative	$1.97	$2.59	$(0.62)	(24)%	$2.18	$2.59	$(0.41)	(16)%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$14.75	$13.34	$1.41	11%	$15.34	$13.14	$2.20	17%
Derivative settlement gain [(2)]	$7.10	$6.85	$0.25	4%	$8.97	$8.24	$0.73	9%
Earnings per share information								
Basic net loss per common share	$(2.48)	$(0.85)	$(1.63)	(192)%	$(7.58)	$(1.64)	$(5.94)	(362)%
Diluted net loss per common share	$(2.48)	$(0.85)	$(1.63)	(192)%	$(7.58)	$(1.64)	$(5.94)	(362)%
Basic weighted-average common shares outstanding (in thousands)	68,102	67,483	619	1%	68,090	67,473	617	1%

Diluted weighted-average common shares outstanding (in thousands)	68,102	67,483	619	1	%	68,090	67,473	617	1	%

30

(1) Amount and percentage changes may not calculate due to rounding.
(2) Derivative settlements for the three and six months ended June 30, 2016, and 2015, 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 derivative settlement gain by $0.93 and $0.46 per BOE 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, 2016, decreased 13 percent and 17 percent, respectively, compared with the same periods in 2015. The decreases were due to the sale of our Mid-Continent assets during the second quarter of 2015, which produced 7.4 MBOE per day and 9.3 MBOE per day during the three and six months ended June 30, 2015, respectively, and due to our reduced drilling and completion activity throughout 2015 and 2016. Overall, we expect our production to be relatively flat quarter-over-quarter for the remainder of 2016, resulting in an overall decrease in production for the full-year 2016 compared to the full-year 2015. Please refer to Comparison of Financial Results and Trends Between the Three Months and Six Months Ended June 30, 2016, and 2015 below for additional discussion.

Changes in production volumes, revenues, and costs reflect the highly volatile nature of our industry. Our realized prices on a per BOE basis for the three and six months ended June 30, 2016, decreased 24 percent and 28 percent, respectively, compared to the same periods in 2015, as a result of lower commodity prices.

Lease operating expense ("LOE") on a per BOE basis remained relatively flat for the three and six months ended June 30, 2016, compared to the same periods in 2015. 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. For full-year 2016, we expect LOE on a per BOE basis to be slightly lower than full-year 2015 as a result of lower service provider costs.

Transportation expense on a per BOE basis slightly increased for the three and six months ended June 30, 2016, compared to the same periods in 2015, due to selling our Mid-Continent assets during the second quarter of 2015, which resulted in our higher cost Eagle Ford shale assets becoming a larger portion of our total production. As a result of this divestiture, we expect the change in our production mix to result in slightly higher transportation costs on a per BOE basis when comparing full-year 2016 to full-year 2015.

Production taxes on a per BOE basis decreased 33 percent and 36 percent for the three and six months ended June 30, 2016, respectively, compared to the same periods in 2015 in line with the decrease in production revenues. Our production tax rate for the three and six months ended June 30, 2016, was 4.6 percent and 4.4 percent, respectively, compared to 5.2 percent and 5.0 percent, respectively, for the same periods in 2015. This decrease in our company-wide production tax rate is primarily a result of divesting our Mid-Continent properties in the second quarter of 2015. 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 also impact or change the amount of production tax we recognize.

Ad valorem tax expense on a per BOE basis decreased 24 percent and 41 percent for the three and six months ended June 30, 2016, respectively, compared to the same periods in 2015. The decrease in ad valorem tax expense on a per BOE basis is primarily due to the lower valuation of properties subject to ad valorem taxes in 2016 as a result of declining commodity prices. 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.

General and administrative ("G&A") expense on a per BOE basis decreased 24 percent and 16 percent for the three and six months ended June 30, 2016, respectively, compared to the same periods in 2015, as our absolute G&A expense decreased at a faster rate than the decrease in production volumes. Absolute G&A expense decreased for the three and six months ended June 30, 2016, compared to the same periods in 2015 primarily due to lower headcount in 2016 than in 2015, and due to the exit and disposal costs incurred during the second quarter of 2015 relating to the closure of our Tulsa, Oklahoma office. Overall, we expect G&A expense on a per BOE basis to be lower for the full-year 2016 compared to the full-year 2015 due to lower headcount and exit and disposal costs incurred during 2015.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion ("DD&A") expense on a per BOE basis increased 11 percent and 17 percent for the three and six months ended June 30, 2016, compared to the same periods in 2015. 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. The decrease in commodity prices has resulted in a decrease in proved reserve volumes and consequently an increased DD&A rate in 2016 compared to 2015. However, the marketing of certain non-core assets in each of our operating regions caused a reduction in our DD&A expense on a per BOE basis in the second quarter of 2016, as these assets were held for sale with no DD&A expense recorded for these assets for the three months ended June 30, 2016. Changes in commodity prices impact our proved reserve volumes, and consequently, we would expect a decrease in commodity prices to increase our DD&A rate and an increase in commodity prices to lower our DD&A rate. For the remainder of 2016, we expect DD&A expense on a per BOE basis to be in line with our second quarter rate or slightly higher upon the closure of divestitures of the properties held for sale at June 30, 2016.

Please refer to Comparison of Financial Results and Trends Between the Three Months and Six Months Ended June 30, 2016, and 2015 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 loss per common share calculations. For the three and six months ended June 30, 2016, and 2015, we recorded losses 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 and Six Months Ended June 30, 2016, and 2015

Oil, gas, and NGL production, revenue, and costs

The following table presents the regional changes in our oil, gas, and NGL production, production revenues, and production costs between the three months ended June 30, 2016, and 2015:

	Average Net Daily Production Increase (Decrease)	Production Revenues Decrease	Production Costs Increase (Decrease)
	(MBOE/d)	(in millions)	(in millions)
South Texas & Gulf Coast	(13.7)	$ (94.6)	$ (17.7)
Rocky Mountain	(3.9)	(45.1)	(2.2)
Permian	1.2	(1.6)	0.2
Mid-Continent [1]	(7.4)	(8.9)	(5.4)
Total	(23.8)	$ (150.2)	$ (25.1)

[1] We divested our Mid-Continent assets in the second quarter of 2015.

The 13 percent decrease in net equivalent production volumes combined with a 24 percent decrease in realized prices on a per BOE basis, resulted in a 34 percent decrease in oil, gas, and NGL production revenues between the three months ended June 30, 2016, and 2015.

Total production costs decreased 14 percent for the three months ended June 30, 2016, compared with the same period of 2015, primarily due to a 13 percent decrease in net equivalent production volumes and the changes in costs on a per BOE basis discussed above.

The following table presents the regional changes in our oil, gas, and NGL production, production revenues, and production costs between the six months ended June 30, 2016, and 2015:

	Average Net Daily Production Decrease	Production Revenues Decrease	Production Costs Decrease
	(MBOE/d)	(in millions)	(in millions)
South Texas & Gulf Coast	(19.4)	$ (212.1)	$ (49.4)
Rocky Mountain	(1.9)	(78.7)	(7.3)
Permian	(0.8)	(16.8)	