CARRIZO OIL & GAS INC
Form 10-Q
May 05, 2016

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

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2016
o TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File Number: 000-29187-87

CARRIZO OIL & GAS, INC.
(Exact name of registrant as specified in its charter)

Texas	76-0415919
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
500 Dallas Street, Suite 2300, Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

(713) 328-1000
(Registrant’s telephone number)

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

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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES x NO ¨

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 (Check one):

Large accelerated filer x	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES ¨ NO x

The number of shares outstanding of the registrant’s common stock, par value $0.01 per share, as of April 29, 2016 was 58,778,280.

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Part I. Financial Information
Item 1. Consolidated Financial Statements (Unaudited)
CARRIZO OIL & GAS, INC.
CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share data)
(Unaudited)

	March 31, 2016	December 31, 2015
Assets		
Current assets		
Cash and cash equivalents	$2,158	$42,918
Accounts receivable, net	56,557	54,721
Derivative assets	96,175	131,100
Other current assets	3,665	3,443
Total current assets	158,555	232,182
Property and equipment		
Oil and gas properties, full cost method		
Proved properties, net	1,160,698	1,369,151
Unproved properties, not being amortized	310,859	335,452
Other property and equipment, net	12,031	12,258
Total property and equipment, net	1,483,588	1,716,861
Deferred income taxes	—	46,758
Derivative assets	—	1,115
Other assets	8,789	10,330
Total Assets	$1,650,932	$2,007,246
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable	$32,716	$74,065
Revenues and royalties payable	56,557	67,808
Accrued capital expenditures	45,081	39,225
Accrued interest	20,941	21,981
Deferred income taxes	—	46,758
Other current liabilities	36,331	35,647
Total current liabilities	191,626	285,484
Long-term debt	1,267,151	1,236,017
Asset retirement obligations	16,911	16,183
Derivative liabilities	17,235	12,648
Other liabilities	13,105	12,860
Total liabilities	1,506,028	1,563,192
Commitments and contingencies		
Shareholders' equity		
Common stock, $0.01 par value, 90,000,000 shares authorized; 58,778,280 issued and outstanding as of March 31, 2016 and 58,332,993 issued and outstanding as of December 31, 2015	588	583
Additional paid-in capital	1,423,321	1,411,081
Accumulated deficit	(1,279,005)	(967,610)
Total shareholders' equity	144,904	444,054
Total Liabilities and Shareholders' Equity	$1,650,932	$2,007,246

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

CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)
(Unaudited)

	Three Months Ended March 31,	
	2016	2015
Revenues		
Crude oil	$67,996	$83,058
Natural gas liquids	3,440	4,473
Natural gas	9,826	12,519
Total revenues	81,262	100,050
Costs and Expenses		
Lease operating	23,675	21,716
Production taxes	3,431	4,018
Ad valorem taxes	2,070	3,033
Depreciation, depletion and amortization	59,577	73,871
General and administrative, net	21,303	31,577
(Gain) loss on derivatives, net	(10,553)	(26,439)
Interest expense, net	18,713	18,196
Impairment of proved oil and gas properties	274,413	—
Other (income) expense, net	(93)	6,992
Total costs and expenses	392,536	132,964
Loss From Continuing Operations Before Income Taxes	(311,274)	(32,914)
Income tax (expense) benefit	(121)	11,438
Loss From Continuing Operations	(311,395)	(21,476)
Income From Discontinued Operations, Net of Income Taxes	—	266
Net Loss	($311,395)	($21,210)
Net Loss Per Common Share - Basic		
Loss from continuing operations	($5.34)	($0.46)
Income from discontinued operations, net of income taxes	—	—
Net loss	($5.34)	($0.46)
Net Loss Per Common Share - Diluted		
Loss from continuing operations	($5.34)	($0.46)
Income from discontinued operations, net of income taxes	—	—
Net income loss	($5.34)	($0.46)
Weighted Average Common Shares Outstanding		
Basic	58,360	46,403
Diluted	58,360	46,403

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

CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)
(Unaudited)

	Three Months Ended March 31, 2016	2015
Cash Flows From Operating Activities		
Net loss	($311,395)	($21,210)
Income from discontinued operations, net of income taxes	—	(266)
Adjustments to reconcile loss from continuing operations to net cash provided by operating activities from continuing operations		
Depreciation, depletion and amortization	59,577	73,871
Impairment of proved oil and gas properties	274,413	—
(Gain) loss on derivatives, net	(10,553)	(26,439)
Cash received for derivative settlements, net	51,163	49,064
Stock-based compensation expense, net	11,522	9,853
Deferred income taxes	—	(11,531)
Non-cash interest expense, net	1,160	1,971
Other, net	1,116	8,248
Changes in operating assets and liabilities-		
Accounts receivable	(2,065)	6,517
Accounts payable	(18,711)	(13,670)
Accrued liabilities	(1,667)	(1,991)
Other, net	(692)	(950)
Net cash provided by operating activities from continuing operations	53,868	73,467
Net cash used in operating activities from discontinued operations	—	(201)
Net cash provided by operating activities	53,868	73,266
Cash Flows From Investing Activities		
Capital expenditures - oil and gas properties	(125,989)	(209,547)
Proceeds from sales of oil and gas properties, net	1,785	285
Other, net	(617)	(2,599)
Net cash used in investing activities from continuing operations	(124,821)	(211,861)
Net cash used in investing activities from discontinued operations	—	(103)
Net cash used in investing activities	(124,821)	(211,964)
Cash Flows From Financing Activities		
Payment of deferred purchase payment	—	(150,000)
Borrowings under credit agreement	73,647	444,000
Repayments of borrowings under credit agreement	(43,097)	(395,000)
Payments of debt issuance costs	(50)	(229)
Sale of common stock, net of offering costs	—	231,581
Proceeds from stock options exercised	—	46
Other, net	(307)	—
Net cash provided by financing activities from continuing operations	30,193	130,398
Net cash provided by financing activities from discontinued operations	—	—
Net cash provided by financing activities	30,193	130,398
Net Decrease in Cash and Cash Equivalents	(40,760)	(8,300)
Cash and Cash Equivalents, Beginning of Period	42,918	10,838
Cash and Cash Equivalents, End of Period	$2,158	$2,538

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

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CARRIZO OIL & GAS, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation

Nature of Operations

Carrizo Oil & Gas, Inc. is a Houston-based energy company which, together with its subsidiaries (collectively, the "Company"), is actively engaged in the exploration, development, and production of oil and gas primarily from resource plays located in the United States. The Company's current operations are principally focused in proven, producing oil and gas plays primarily in the Eagle Ford Shale in South Texas, the Delaware Basin in West Texas, the Niobrara Formation in Colorado, the Utica Shale in Ohio, and the Marcellus Shale in Pennsylvania.

Consolidated Financial Statements

The accompanying unaudited interim consolidated financial statements include the accounts of the Company after elimination of intercompany transactions and balances and have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (the "SEC") and therefore do not include all disclosures required for financial statements prepared in conformity with accounting principles generally accepted in the U.S. ("GAAP"). In the opinion of management, these financial statements include all adjustments (consisting of normal recurring accruals and adjustments) necessary to present fairly, in all material respects, the Company's interim financial position, results of operations and cash flows. However, the results of operations for the periods presented are not necessarily indicative of the results of operations that may be expected for the full year. These financial statements and related notes included in this Quarterly Report on Form 10-Q should be read in conjunction with the Company's audited Consolidated Financial Statements and related notes included in the Company's Annual Report on Form 10-K for the year ended December 31, 2015 ("2015 Annual Report"). Certain reclassifications have been made to prior period amounts to conform to the current period presentation. Such reclassifications had no material impact on prior period amounts.

2. Summary of Significant Accounting Policies

The Company has provided a discussion of significant accounting policies, estimates, and judgments in "Note 2. Summary of Significant Accounting Policies" of the Notes to Consolidated Financial Statements in its 2015 Annual Report. There have been no changes to the Company's significant accounting policies since December 31, 2015, other than the recently adopted accounting pronouncements described below.

Recently Adopted Accounting Pronouncements

In November 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2015-17, Balance Sheet Classification of Deferred Taxes ("Update 2015-17"). Update 2015-17 requires that all deferred tax liabilities and assets, as well as any related valuation allowance, be classified in the balance sheet as noncurrent. For public entities, Update 2015-17 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 31, 2016 and may be applied prospectively to all deferred tax assets and liabilities or retrospectively to all periods presented with early adoption permitted. The Company elected to early adopt Update 2015-17 in the first quarter of 2016 with prospective application. As the Company elected a prospective application, there was no impact to prior period amounts.

In April 2015, the FASB issued Accounting Standards Update No. 2015-03, Simplifying the Presentation of Debt Issuance Costs ("Update 2015-03"). The objective of Update 2015-03 is to simplify the presentation of debt issuance costs in financial statements by presenting such costs in the balance sheet as a direct deduction from the related debt rather than as an asset. In August 2015, the FASB issued Accounting Standards Update No. 2015-15, Interest-Imputation of Interest (Subtopic 835-30) ("Update 2015-15"), which allows debt issuance costs associated with line-of-credit agreements to be deferred and presented as an asset in the balance sheet, subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings. For public entities, these Updates are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015 and applied retrospectively with early adoption permitted. As a result of the adoption of Update 2015-03 and Update 2015-15 in the first quarter of 2016, the Company reclassified $19.7 million of debt issuance costs related to the Company's senior notes from long-term assets to long-term debt in the Company's consolidated balance sheet as of December 31, 2015. The Company elected to continue to present the debt issuance costs associated with its revolving credit facility as long-term assets in the consolidated balance sheets.

Recently Issued Accounting Pronouncements

In March 2016, the FASB issued Accounting Standards Update No. 2016-09, Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting ("Update 2016-09"), which seeks to simplify several aspects of the accounting for share-based payment award transactions, including income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. For public entities, Update 2016-09 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016, with early adoption permitted. The Company is currently evaluating the impact of the adoption of Update 2016-09 on its consolidated financial statements.

In February 2016, the FASB issued Accounting Standards Update No. 2016-02, Leases (Topic 842) ("Update 2016-02"), which seeks to increase transparency and comparability among organizations by, among other things, recognizing lease assets and lease liabilities on the balance sheet for leases classified as operating leases under previous GAAP and disclosing key information about leasing arrangements. For public entities, Update 2016-02 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018 and must be applied using a modified retrospective transition with early adoption permitted. The Company is currently evaluating the impact of the adoption of Update 2016-02 on its consolidated financial statements.

In May 2014, the FASB issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("Update 2014-09"), which supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and industry specific guidance in Subtopic 932-605, Extractive Activities- Oil and Gas- Revenue Recognition. Update 2014-09 requires entities to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods and services. Update 2014-09 is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period for public entities. In March 2016, the FASB released certain implementation guidance through ASU 2016-08 to clarify principal versus agent considerations. The Company is currently evaluating the impact of the adoption of Update 2014-09 and the subsequently issued clarification updates on its consolidated financial statements.

3. Property and Equipment, Net

As of March 31, 2016 and December 31, 2015, total property and equipment, net consisted of the following:

	March 31, 2016	December 31, 2015
	(In thousands)	
Proved properties	$4,100,674	$3,976,511
Accumulated depreciation, depletion and amortization and impairment	(2,939,976)	(2,607,360)
Proved properties, net	1,160,698	1,369,151
Unproved properties, not being amortized		
Unevaluated leasehold and seismic costs	261,136	280,263
Exploratory wells in progress	4,122	9,432
Capitalized interest	45,601	45,757
Total unproved properties, not being amortized	310,859	335,452
Other property and equipment	23,123	22,677
Accumulated depreciation	(11,092)	(10,419)
Other property and equipment, net	12,031	12,258
Total property and equipment, net	$1,483,588	$1,716,861

Capitalized oil and gas property costs within a cost center are amortized on an equivalent unit-of-production method, converting natural gas to barrels of oil equivalent at the ratio of six thousand cubic feet of natural gas to one barrel of crude oil, which represents their approximate relative energy content. Average depreciation, depletion and amortization ("DD&A") per Boe of proved properties was $15.22 and $23.43 for the three months ended March 31, 2016 and 2015, respectively.

The Company capitalized internal costs of employee compensation and benefits, including stock-based compensation, directly associated with acquisition, exploration and development activities totaling $4.4 million and $5.8 million for the three months ended March 31, 2016 and 2015, respectively.

Unproved properties, not being amortized, include unevaluated leasehold and seismic costs associated with specific unevaluated properties, the cost of exploratory wells in progress and related capitalized interest. The Company capitalized interest costs associated with its unevaluated leasehold and seismic costs and exploratory well costs totaling $5.6 million and $9.7 million for the three months ended March 31, 2016 and 2015, respectively.

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Full Cost Ceiling Test Impairment

In the first quarter of 2016, the Company recorded an after-tax impairment in the carrying value of proved oil and gas properties of $178.4 million ($274.4 million pre-tax) due primarily to a 9% decrease in the average realized price for sales of crude oil on the first calendar day of each month during the preceding 12-month period prior to March 31, 2016 as compared to the preceding 12-month period prior to December 31, 2015. There were no impairments of proved oil and gas properties for the three months ended March 31, 2015.

The Company expects to record an impairment in the carrying value of proved oil and gas properties in the second quarter of 2016, due primarily to a forecasted average realized price for sales of crude oil on the first calendar day of each month during the preceding 12-month period prior to June 30, 2016 of $39.21 compared to the preceding 12-month period prior to March 31, 2016 of $43.14, a 9% decrease. This forecasted average realized price was based on the average realized price for sales of crude oil on the first calendar day of each month for the first 11 months and an estimate for the twelfth month based on a quoted forward price. Further impairments in subsequent quarters may occur if the trailing 12-month commodity prices continue to be lower than the comparable trailing 12-month commodity prices discussed above.

4. Income Taxes

The Company’s estimated annual effective income tax rates are used to allocate expected annual income tax expense or benefit to interim periods. The rates are the ratio of estimated annual income tax expense or benefit to estimated annual income or loss before income taxes by taxing jurisdiction, except for discrete items, which are significant, unusual or infrequent items for which income taxes are computed and recorded in the interim period in which the discrete item occurs. The estimated annual effective income tax rates are applied to the year-to-date income or loss before income taxes by taxing jurisdiction to determine the income tax expense or benefit allocated to the interim period. The Company updates its estimated annual effective income tax rates at the end of each quarterly period considering the geographic mix of income based on the tax jurisdictions in which the Company operates. Actual results that are different from the assumptions used in estimating the annual effective income tax rates will impact future income tax expense or benefit.

The Company’s income tax (expense) benefit from continuing operations differs from the income tax (expense) benefit computed by applying the U.S. federal statutory corporate income tax rate of 35% to loss from continuing operations before income taxes as follows:

	Three Months Ended March 31,	
	2016	2015
	(In thousands)	
Loss from continuing operations before income taxes	($311,274)	($32,914)
Income tax benefit at the statutory rate	108,946	11,520
State income tax (expense) benefit, net of U.S. Federal income taxes	1,619	(76)
Deferred tax asset valuation allowance	(110,679)	—
Other	(7)	(6)
Total income tax (expense) benefit	($121)	$11,438

from continuing
operations

Deferred Tax Asset Valuation Allowance

Deferred tax assets are recorded for net operating losses and temporary differences between the book and tax basis of assets and
liabilities expected to produce tax deductions in future periods. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those deferred tax assets would be deductible. The Company assesses the realizability of its deferred tax assets each period by considering whether it is more likely than not that all or a portion of the deferred tax assets will not be realized. The Company considers all available evidence (both positive and negative) when determining whether a valuation allowance is required. In making this assessment, the Company evaluated possible sources of taxable income that may be available to realize the deferred tax assets, including projected future taxable income, the reversal of existing temporary differences, taxable income in carryback years and available tax planning strategies.

A significant item of objective negative evidence considered was the cumulative historical three year pre-tax loss and a net deferred tax asset position at March 31, 2016, driven primarily by the full cost ceiling test impairments recognized during the second half of 2015 and the first quarter of 2016, which limits the ability to consider other subjective evidence such as the Company’s potential for future growth. The Company has concluded that it is more likely than not the deferred tax assets will not be realized and recorded additional valuation allowance totaling $110.7 million against the net deferred tax asset as of March 31, 2016, reducing the net deferred tax assets to zero.

The Company will continue to evaluate whether the valuation allowance is needed in future reporting periods. The valuation allowance will remain until the Company can determine that the net deferred tax assets are more likely than not to be realized. Future events or new evidence which may lead the Company to conclude that it is more likely than not its net deferred tax assets will be realized include, but are not limited to, cumulative historical pre-tax earnings, improvements in crude oil prices, and taxable events that could result from one or more transactions. The valuation allowance does not prevent future utilization of the tax attributes if the Company recognizes taxable income. As long as the Company concludes that the valuation allowance against its net deferred tax assets is necessary, the Company likely will not have any additional deferred income tax expense or benefit.

5. Long-Term Debt

Long-term debt consisted of the following as of March 31, 2016 and December 31, 2015:

	March 31, 2016	December 31, 2015
	(In thousands)	
Senior Secured Revolving Credit Facility due 2018	$30,550	$—
7.50% Senior Notes due 2020	600,000	600,000
Unamortized premium for 7.50% Senior Notes	1,195	1,251
Unamortized debt issuance costs for 7.50% Senior Notes	(8,682)	(9,048)
6.25% Senior Notes due 2023	650,000	650,000
Unamortized debt issuance costs for 6.25% Senior Notes	(10,337)	(10,611)
Other long-term debt due 2028	4,425	4,425
Long-term debt	$1,267,151	$1,236,017

Senior Secured Revolving Credit Facility

The Company has a senior secured revolving credit facility with a syndicate of banks that, as of March 31, 2016, had a borrowing base of $685.0 million, with $30.6 million of borrowings outstanding with a weighted average interest rate of 2.01%. As of March 31, 2016, the Company also had $0.6 million in letters of credit outstanding, which reduce the amounts available under the revolving credit facility. The credit agreement governing the revolving credit facility provides for interest-only payments until July 2, 2018, when the credit agreement matures and any outstanding borrowings are due. The borrowing base under the credit agreement is subject to regular redeterminations in the Spring and Fall of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base. The amount the Company is able to borrow with respect to the borrowing base is subject to compliance with the financial covenants and other provisions of the credit agreement governing the revolving credit facility.

The obligations of the Company under the credit agreement are guaranteed by the Company’s material domestic subsidiaries and are secured by liens on substantially all of the Company’s assets, including a mortgage lien on oil and gas properties having at least 80% of the proved reserve value of the oil and gas properties included in the determination of the borrowing base.

Amounts outstanding under the credit agreement bear interest at the Company’s option at either (i) a base rate for a base rate loan plus the margin set forth in the table below, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.50% and the adjusted LIBO rate plus 1.00%, or (ii) an adjusted LIBO rate for a Eurodollar loan plus the margin set forth in the table below. The Company also incurs commitment fees as set forth in the table below on the unused portion of lender commitments, which are included as a component of interest expense, net.

Ratio of Outstanding Borrowings and Letters of Credit to Lender Commitments	Applicable Margin for Base Rate Loans	Applicable Margin for Eurodollar Loans	Commitment Fee
Less than 25%	0.50%	1.50%	0.375%
Greater than or equal to 25% but less than 50%	0.75%	1.75%	0.375%
Greater than or equal to 50% but less than 75%	1.00%	2.00%	0.500%
Greater than or equal to 75% but less than 90%	1.25%	2.25%	0.500%

Greater than or equal to 90%	1.50%	2.50%	0.500%

As of March 31, 2016, the Company was subject to certain covenants under the terms of the credit agreement, which include the maintenance of the following financial covenants determined as of the last day of each quarter: (1) a ratio of Total Debt to EBITDA of not more than 4.75 to 1.00 through December 31, 2016, reducing to 4.375 to 1.00 through December 31, 2017, and to 4.00 to 1.00 thereafter; and (2) a Current Ratio of not less than 1.00 to 1.00. As defined in the credit agreement, Total Debt excludes debt discounts, premiums, and debt issuance costs and is net of cash and cash equivalents, EBITDA includes the last four quarters after giving pro forma effect to EBITDA for material acquisitions and dispositions of oil and gas properties, and the Current Ratio includes an add back of the unused portion of lender commitments. As of March 31, 2016, the ratio of Total Debt to EBITDA was 2.89 to 1.00 and the Current Ratio was 4.14 to 1.00. Because the financial covenants are determined as of the last day of each quarter, the ratios can fluctuate significantly period to period as the amounts outstanding under the credit agreement are dependent on the timing of cash flows from operations, capital expenditures, acquisitions and dispositions of oil and gas properties and securities offerings. Each of the capitalized terms used but not defined in this paragraph shall have the meaning given to such terms in the credit agreement governing the Company's revolving credit facility.

The credit agreement also places restrictions on the Company and certain of its subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of the Company's common stock, redemptions of senior notes, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

The credit agreement is subject to customary events of default, including in connection with a change in control. If an event of default occurs and is continuing, the lenders may elect to accelerate amounts due under the credit agreement (except in the case of a bankruptcy event of default, in which case such amounts will automatically become due and payable).

On May 3, 2016, the Company entered into an amendment to the credit agreement governing the revolving credit facility. See "Note 13. Subsequent Events" for further details of this amendment. As a result of the Spring 2016 borrowing base redetermination, the Company's borrowing base was reduced from $685.0 million to $600.0 million.

6. Commitments and Contingencies

From time to time, the Company is party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not currently expect these matters to have a materially adverse effect on the financial position or results of operations of the Company.

The results of operations and financial position of the Company continue to be affected from time to time in varying degrees by domestic and foreign political developments as well as legislation and regulations pertaining to restrictions on crude oil and natural gas production, imports and exports, natural gas regulation, tax increases, environmental regulations and cancellation of contract rights. Both the likelihood and overall effect of such occurrences on the Company vary greatly and are not predictable.

7. Shareholders' Equity

Stock-Based Compensation Expense

The Company recognized the following stock-based compensation expense, net for the periods indicated which is reflected as "General and administrative, net" in the consolidated statements of operations:

	Three Months Ended March 31,	
	2016	2015
	(In thousands)	
Restricted stock awards and units	$11,594	$5,215
Stock appreciation rights	1,232	5,940
Performance share awards	616	269
	13,442	11,424
Less: amounts capitalized to oil and gas properties	(1,920)	(1,571)
Total stock-based compensation expense, net	$11,522	$9,853
Income tax benefit	$4,033	$3,449

8. Earnings Per Share

Basic loss from continuing operations per common share is based on the weighted average number of shares of common stock outstanding during the period. Diluted loss from continuing operations per common share is based on the weighted average number of common shares and all potentially dilutive common shares outstanding during the period which include restricted stock awards and units, performance share awards, stock options and warrants. The Company excludes the number of awards, units, options and warrants from the calculation of diluted weighted average shares outstanding when the grant date or exercise prices are greater than the average market prices of the Company's common stock for the period as the effect would be anti-dilutive to the computation. The Company includes the number of performance share awards in the calculation of diluted weighted average common shares outstanding based on the number of shares, if any, that would be issuable as if the end of the period was the end of the performance

period. When a loss from continuing operations exists, all potentially dilutive common shares outstanding are anti-dilutive and therefore excluded from the calculation of diluted weighted average shares outstanding.
Supplemental loss from continuing operations per common share information is provided below:

	Three Months Ended March 31,	
	2016	2015
	(In thousands, except per share amounts)	
Loss from Continuing Operations	($311,395)	($21,476)
Basic weighted average common shares outstanding	58,360	46,403
Effect of dilutive instruments	—	—
Diluted weighted average common shares outstanding	58,360	46,403
Loss from Continuing Operations Per Common Share		
Basic	($5.34)	($0.46)
Diluted	($5.34)	($0.46)

For the three months ended March 31, 2016 and 2015, the Company reported a loss from continuing operations. As a result, the calculation of diluted weighted average common shares outstanding excluded the anti-dilutive effect of 0.6 million and 0.8 million shares of restricted stock awards and units and performance share awards for the three months ended March 31, 2016 and 2015, respectively. For the three months ended March 31, 2015, the calculation of diluted weighted average common shares outstanding also excluded the anti-dilutive effect of an insignificant number of shares of stock options and warrants due to the loss from continuing operations for the period.

9. Derivative Instruments

The Company uses commodity derivative instruments to reduce its exposure to commodity price volatility for a substantial, but varying, portion of its forecasted crude oil and natural gas production and thereby achieve a more predictable level of cash flows to support the Company’s drilling and completion capital expenditure program. The Company does not enter into derivative instruments for speculative or trading purposes. As of March 31, 2016, the Company’s commodity derivative instruments consisted of fixed price swaps, costless collars, and purchased and sold call options, which are described below.

Fixed Price Swaps: The Company receives a fixed price and pays a variable market price to the counterparties over specified periods for contracted volumes.

Costless Collars: A collar is a combination of options including a purchased put option (fixed floor price) and a sold call option (fixed ceiling price) and allows the Company to benefit from increases in commodity prices up to the fixed ceiling price and protect the Company from decreases in commodity prices below the fixed floor price. At settlement, if the market price is below the fixed floor price or is above the fixed ceiling price, the Company receives the fixed price and pays the market price. If the market price is between the fixed floor price and fixed ceiling price, no payments are due from either party. These contracts were executed contemporaneously with the same counterparties and were premium neutral such that no premiums were paid to or received from the counterparties.

Sold Call Options: These contracts give the counterparties the right, but not the obligation, to buy contracted volumes from the Company over specified periods and prices in the future. At settlement, if the market price exceeds the fixed price of the call option, the Company pays the counterparty the excess. If the market price settles below the fixed price of the call option, no payment is due from either party.

Purchased Call Options: These contracts give the Company the right, but not the obligation, to buy contracted volumes from the counterparties over specified periods and prices in the future. At settlement, if the market price exceeds the fixed price of the call option, the counterparties pay the Company the excess. If the market price settles below the fixed price of the call option, no payment is due from either party. The Company nets its purchased call options with its sold call options for the years 2018 through 2020 in the open crude oil derivative positions table below.

The following sets forth a summary of the Company's open crude oil derivative positions at average NYMEX prices as of March 31, 2016:

Period	Type of Contract	Crude Oil Volumes (in Bbls/d)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)
April - December 2016	Fixed Price Swaps	9,750	$60.03	
April - December 2016	Costless Collars	4,000	$50.00	$76.50
January - June 2017	Fixed Price Swaps	12,000	$50.13	
FY 2018	Sold Call Options	2,488		$60.00
FY 2018	Sold Call Options	900		$75.00
FY 2019	Sold Call Options	2,975		$62.50
FY 2019	Sold Call Options	900		$77.50
FY 2020	Sold Call Options	3,675		$65.00
FY 2020	Sold Call Options	900		$80.00

The following sets forth a summary of the Company's open natural gas derivative positions at average NYMEX prices as of March 31, 2016:

Period	Type of Contract	Natural Gas Volumes (in MMBtu/d)	Weighted Average Ceiling Price ($/MMBtu)
FY 2017	Sold Call Options	33,000	$3.00
FY 2018	Sold Call Options	33,000	$3.25
FY 2019	Sold Call Options	33,000	$3.25
FY 2020	Sold Call Options	33,000	$3.50

In February 2015, the Company entered into derivative transactions offsetting its then existing crude oil derivative positions covering the periods from March 2015 through December 2016. As a result of the offsetting derivative transactions, the Company locked in $166.4 million of cash flows, of which $18.3 million was received due to contract settlements during the three months ended March 31, 2016, and is included in the gain on derivatives, net in the consolidated statements of operations. As of March 31, 2016, the fair value of the remaining locked in cash flows is $29.1 million, all of which is a current asset and is classified as "Derivative assets" in the consolidated balance sheets. The derivative assets associated with the offsetting derivative transactions are not subject to price risk and the locked in cash flows will be received as the applicable contracts settle. The offsetting derivative transactions are not included in the table above.

In February 2016, the Company sold out-of-the-money natural gas call options for the years 2017 through 2020 and used the associated premium value to obtain a higher weighted average fixed price of $50.27 per Bbl on 6,000 Bbls/d of newly executed crude oil fixed price swaps for the first half of 2017. These out-of-the-money natural gas call options and in-the-money crude oil fixed price swaps were executed contemporaneously with the same counterparty, therefore, no cash premiums were paid to or received from the counterparty as the premium value associated with the natural gas call options was immediately applied to the crude oil fixed price swaps.

In March 2016, the Company sold 6,000 Bbls/d of in-the-money crude oil fixed price swaps for the first half of the year 2017 at a weighted average fixed price of $50.00 per Bbl. In order to obtain this higher weighted average fixed price, the Company incurred net premiums of approximately $5.6 million, which the Company will pay in two equal payments at the end of the second and third quarters of 2016. In addition to these premiums, during the fourth quarter of 2015, the Company incurred net premiums of approximately $5.0 million related to the simultaneous purchase and sale of out-of-the-money crude oil call options, the payment of which is deferred until settlement. For further discussion of this fourth quarter of 2015 transaction, see "Note 13. Derivative Instruments" of the Notes to Consolidated Financial Statements in the Company's 2015 Annual Report.

For the three months ended March 31, 2016 and 2015, the Company recorded in the consolidated statements of operations a gain on derivatives, net of $10.6 million and $26.4 million, respectively.

The Company typically has numerous hedge positions that span several time periods and often result in both fair value asset and liability positions held with that counterparty, which positions are all offset to a single fair value asset or liability at the end of each reporting period, including the deferred premiums associated with its hedge positions. The Company nets its derivative instrument fair values executed with the same counterparty pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. The fair value of derivative instruments where the Company is in a net asset position with its counterparties as of March 31, 2016 and December 31, 2015 totaled $78.9 million and $119.6 million, respectively, and is summarized by counterparty in the table below:

Counterparty	March 31, 2016		December 31, 2015	
Societe Generale	32	%	37	%
Wells Fargo	32	%	35	%
Citibank	19	%	13	%
Regions	9	%	9	%
Union Bank	6	%	5	%
Capital One	2	%	1	%
Total	100	%	100	%

The counterparties to the Company's derivative instruments are also lenders under the Company's credit agreement which allows the Company to satisfy any need for margin obligations associated with derivatives liabilities with the collateral securing the credit agreement, thus eliminating the need for independent collateral posting.

Because each of the counterparties have investment grade credit ratings, the Company believes it does not have significant credit risk and accordingly does not currently require its counterparties to post collateral to support the net asset positions of its derivative instruments. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties to its derivative instruments. Although the Company does not currently anticipate such nonperformance, it continues to monitor the credit ratings of its counterparties.

10. Fair Value Measurements

Accounting guidelines for measuring fair value establish a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

Level 1 – Observable inputs such as quoted prices in active markets at the measurement date for identical, unrestricted assets or liabilities.

Level 2 – Other inputs that are observable directly or indirectly such as quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.

Level 3 – Unobservable inputs for which there is little or no market data and which the Company makes its own assumptions about how market participants would price the assets and liabilities.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
The following tables summarize the location and amounts of the Company's assets and liabilities measured at fair value on a recurring basis as presented in the consolidated balance sheets as of March 31, 2016 and December 31, 2015. All items included in the tables below are Level 2 inputs within the fair value hierarchy:

	March 31, 2016		
	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
	(In thousands)		
Derivative assets			
Derivative assets-current	$121,899	($25,724)	$96,175
Derivative assets-non current	8,497	(8,497)	—
Derivative liabilities			
Other current liabilities	(25,724)	25,724	—
Derivative liabilities-non current	(25,732)	8,497	(17,235)
Total	$78,940	$—	$78,940

	December 31, 2015		
	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
	(In thousands)		
Derivative assets			
Derivative assets-current	$159,447	($28,347)	$131,100
Derivative assets-non current	10,780	(9,665)	1,115
Derivative liabilities			
Other current liabilities	(28,364)	28,347	(17)
Derivative liabilities-non current	(22,313)	9,665	(12,648)
Total	$119,550	$—	$119,550

The fair values of the Company's derivative assets and liabilities are based on a third-party industry-standard pricing model that uses market data obtained from third-party sources, including quoted forward prices for crude oil and natural gas, discount rates and volatility factors. The fair values are also compared to the values provided by the counterparties for reasonableness and are adjusted for the counterparties' credit quality for derivative assets and the Company's credit quality for derivative liabilities. To date, adjustments for credit quality have not had a material impact on the fair values.

The derivative asset and liability fair values reported in the consolidated balance sheets that pertain to the Company's derivative instruments are as of a particular point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. However, the fair value of the net derivative asset attributable to the offsetting crude oil derivative transactions are not subject to price risk as changes in the fair value of the original positions are offset by changes in the fair value of the offsetting positions. The Company typically has numerous hedge positions that span several time periods and often result in both derivative assets and liabilities with the same counterparty, which positions are all offset to a single derivative asset or liability in the consolidated balance sheets, including the deferred premiums associated with its hedge positions. The Company nets the fair values of its derivative assets and liabilities associated with derivative instruments executed with the same counterparty pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. The Company had no transfers into Level 1 and no transfers into or out of Level 2 for the three months ended March 31, 2016 and 2015.

Fair Value of Other Financial Instruments

The Company’s other financial instruments consist of cash and cash equivalents, receivables, payables and long-term debt, which are classified as Level 1 under the fair value hierarchy. The carrying amounts of cash and cash equivalents, receivables, and payables approximate fair value due to the highly liquid or short-term nature of these instruments. The carrying amount of long-term debt under the Company’s revolving credit facility approximates fair value as borrowings bear interest at variable rates. The following table presents the carrying amounts of the Company's senior notes and other long-term debt, net of debt premiums and debt issuance costs, with the fair values of each based on quoted market prices.

	March 31, 2016		December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
7.50% Senior Notes due 2020	$592,513	$553,500	$592,203	$528,000
6.25% Senior Notes due 2023	639,663	562,250	639,389	533,000
Other long-term debt due 2028	4,425	4,054	4,425	4,182

11. Condensed Consolidating Financial Information

The rules of the SEC require that condensed consolidating financial information be provided for a subsidiary that has guaranteed the debt of a registrant issued in a public offering, where the guarantee is full, unconditional and joint and several and where the voting interest of the subsidiary is 100% owned by the registrant. The Company is, therefore, presenting condensed consolidating financial information on a parent company, combined guarantor subsidiaries, combined non-guarantor subsidiaries and consolidated basis and should be read in conjunction with the consolidated financial statements. The financial information may not necessarily be indicative of results of operations, cash flows, or financial position had such guarantor subsidiaries operated as independent entities.

CARRIZO OIL & GAS, INC.
CONDENSED CONSOLIDATING BALANCE SHEETS
(In thousands)
(Unaudited)

	March 31, 2016				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Total current assets	$2,557,853	$53,059	$—	($2,452,357)	$158,555
Total property and equipment, net	44,212	1,439,376	3,800	(3,800)	1,483,588
Investment in subsidiaries	(1,095,983)	—	—	1,095,983	—
Other assets	8,633	156	—	—	8,789
Total Assets	$1,514,715	$1,492,591	$3,800	($1,360,174)	$1,650,932
Liabilities and Shareholders' Equity					
Current liabilities	$73,439	$2,569,765	$3,800	($2,455,378)	$191,626
Long-term liabilities	1,279,765	18,809	—	15,828	1,314,402
Total shareholders' equity	161,511	(1,095,983)	—	1,079,376	144,904
Total Liabilities and Shareholders' Equity	$1,514,715	$1,492,591	$3,800	($1,360,174)	$1,650,932

	December 31, 2015				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Total current assets	$2,578,034	$52,067	$—	($2,397,919)	$232,182
Total property and equipment, net	44,499	1,671,774	3,059	(2,471)	1,716,861
Investment in subsidiaries	(815,836)	—	—	815,836	—
Other assets	74,679	156	—	(16,632)	58,203
Total Assets	$1,881,376	$1,723,997	$3,059	($1,601,186)	$2,007,246
Liabilities and Shareholders' Equity					
Current liabilities	$161,792	$2,521,572	$3,059	($2,400,939)	$285,484
Long-term liabilities	1,260,200	18,261	—	(753)	1,277,708
Total shareholders' equity	459,384	(815,836)	—	800,506	444,054
Total Liabilities and Shareholders' Equity	$1,881,376	$1,723,997	$3,059	($1,601,186)	$2,007,246

CARRIZO OIL & GAS, INC.
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(In thousands)
(Unaudited)

	Three Months Ended March 31, 2016				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$115	$81,147	$—	$—	$81,262
Total costs and expenses	29,912	362,248	—	376	392,536
Loss from continuing operations before income taxes	(29,797)	(281,101)	—	(376)	(311,274)
Income tax expense	—	—	—	(121)	(121)
Equity in loss of subsidiaries	(281,101)	—	—	281,101	—
Loss from continuing operations	(310,898)	(281,101)	—	280,604	(311,395)
Income from discontinued operations, net of income taxes	—	—	—	—	—
Net loss	($310,898)	($281,101)	$—	$280,604	($311,395)

	Three Months Ended March 31, 2015				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$590	$99,403	$57	$—	$100,050
Total costs and expenses	26,668	104,912	216	1,168	132,964
Loss from continuing operations before income taxes	(26,078)	(5,509)	(159)	(1,168)	(32,914)
Income tax benefit	9,128	1,928	55	327	11,438
Equity in loss of subsidiaries	(3,685)	—	—	3,685	—
Loss from continuing operations	(20,635)	(3,581)	(104)	2,844	(21,476)
Income from discontinued operations, net of income taxes	266	—	—	—	266
Net loss	($20,369)	($3,581)	($104)	$2,844	($21,210)

CARRIZO OIL & GAS, INC.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(In thousands)
(Unaudited)

	Three Months Ended March 31, 2016				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities from continuing operations	($2,156)	$56,024	$—	$—	$53,868
Net cash used in investing activities from continuing operations	(68,797)	(122,849)	(740)	67,565	(124,821)
Net cash provided by financing activities from continuing operations	30,193	66,825	740	(67,565)	30,193
Net cash used in discontinued operations	—	—	—	—	—
Net decrease in cash and cash equivalents	(40,760)	—	—	—	(40,760)
Cash and cash equivalents, beginning of period	42,918	—	—	—	42,918
Cash and cash equivalents, end of period	$2,158	$—	$—	$—	$2,158

	Three Months Ended March 31, 2015				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities from continuing operations	($17,989)	$91,452	$4	$—	$73,467
Net cash used in investing activities from continuing operations	(270,404)	(191,193)	(18,345)	268,081	(211,861)
Net cash provided by financing activities from continuing operations	280,397	99,741	18,341	(268,081)	130,398
Net cash used in discontinued operations	(304)	—	—	—	(304)
Net decrease in cash and cash equivalents	(8,300)	—	—	—	(8,300)
Cash and cash equivalents, beginning of period	10,838	—	—	—	10,838
Cash and cash equivalents, end of period	$2,538	$—	$—	$—	$2,538

12. Supplemental Cash Flow Information

Supplemental disclosures to the consolidated statements of cash flows are presented below:

	Three Months Ended March 31,	
	2016	2015
	(In thousands)	
Non-cash investing and financing activities:		
Change in capital expenditure payables and accruals	($27,989)	($30,208)

13. Subsequent Events

On May 3, 2016, the Company entered into an amendment to the credit agreement governing the revolving credit facility (the "Eighth Amendment") to, among other things (i) replace the Total Debt to EBITDA ratio covenant with a Total Secured Debt to EBITDA ratio covenant that requires such ratio not to exceed 2.00 to 1.00, (ii) add a covenant requiring a minimum EBITDA to Interest Expense ratio of at least 2.50 to 1.00, (iii) reduce the Borrowing Base under the credit facility from $685.0 million to $600.0 million until the next redetermination thereof, (iv) increase the required mortgage coverage on the total value of the oil and gas properties included in the Company's most recent reserve report from 80% to 90%, (v) require that the Company's deposit accounts and securities accounts (subject to certain exclusions) become subject to control agreements, (vi) limit the amount of additional senior notes that can be issued by the Company to $400.0 million, (vii) restrict the Company from making borrowings under the credit facility if the Company has or, after giving effect to the borrowing, will have a Consolidated Cash Balance in excess of $50.0 million, (viii) require mandatory prepayment of borrowings to the extent the Consolidated Cash Balance exceeds $50.0 million if either (a) the Company's ratio of Total Debt to EBITDA exceeds 3.50 to 1.00 or (b) the availability under the credit facility is equal to or less than 20% of the then effective Borrowing Base, (ix) increase the margin on all loans by 0.50%, and (x) increase the commitment fee from 0.375% to 0.50% when utilization of lender commitments is less than 50%. Each of the capitalized terms used but not defined in this note to the consolidated financial statements shall have the meaning given to such terms in the credit agreement governing the Company's revolving credit facility.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is management's discussion and analysis of the significant factors that affected the financial position and results of operations of Carrizo Oil & Gas, Inc. and its subsidiaries (collectively, the "Company") during the periods included in the accompanying unaudited consolidated financial statements. You should read this in conjunction with the unaudited interim consolidated financial statements included in this Quarterly Report on Form 10-Q and the discussion under "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the audited Consolidated Financial Statements included in our Annual Report on Form 10-K for the year ended December 31, 2015 ("2015 Annual Report").

General Overview

Production, Commodity Prices and Revenue. Total production for the three months ended March 31, 2016 increased 21% from the three months ended March 31, 2015 to 42,025 Boe/d, of which 74% was in the Eagle Ford. Crude oil production for the three months ended March 31, 2016 was 25,806 Bbls/d, an increase of 21% from the three months ended March 31, 2015, primarily driven by strong performance from our wells in the Eagle Ford, which averaged 22,769 Bbls/d. Driven primarily by the 33% decrease in average realized crude oil prices, revenues for the first quarter of 2016 decreased to $81.3 million. For further discussion of production, commodity prices and revenue, see "—Results of Operations" below.

Operational Highlights. See the table below for details of our operated drilling and completion activity by region:

	Three Months Ended March 31, 2016				March 31, 2016				
	Drilled		Wells Brought on Production		Waiting on Completion		Producing		Rig count
Region	Gross	Net	Gross	Net	Gross	Net	Gross	Net	
Eagle Ford	18	17.0	14	12.5	33	31.8	275	241.3	2
Niobrara	—	—	—	—	9	5.2	123	53.7	—
Marcellus	—	—	—	—	11	4.3	81	26.0	—
Utica	—	—	—	—	—	—	4	3.1	—
Delaware Basin	1	1.0	1	1.0	2	1.9	3	2.7	—
Total	19	18.0	15	13.5	55	43.2	486	326.8	2

Financing Activities. On May 3, 2016, we entered into an amendment to the credit agreement governing the revolving credit facility (the "Eighth Amendment") which, among other things, (i) replaces the Total Debt to EBITDA ratio covenant with a Total Secured Debt to EBITDA ratio covenant that requires such ratio not to exceed 2.00 to 1.00, (ii) adds a covenant requiring a minimum EBITDA to Interest Expense ratio of at least 2.50 to 1.00, and (iii) reduces the Borrowing Base under the credit facility from $685.0 million to $600.0 million until the next redetermination thereof. See "— Financing Arrangements—Senior Secured Revolving Credit Facility" for additional details.

2016 Capital Expenditure Plan. Our current 2016 drilling and completion capital expenditure plan remains unchanged at$270.0 million to $290.0 million for drilling and completion and our 2016 leasehold and seismic capital expenditure plan is increased to $20.0 million from $15.0 million as a result of our outlook for continued bolt-on acquisitions. Approximately 85% of our first quarter 2016 drilling and completion capital expenditures were in the Eagle Ford. Approximately 90% of the 2016 drilling and completion capital expenditure plan is allocated to the continued development of the Eagle Ford. See "—Liquidity and Capital Resources—2016 Capital Expenditure Plan and Funding Strategy" for additional details.

Results of Operations

Three Months Ended March 31, 2016, Compared to the Three Months Ended March 31, 2015

The following table summarizes total production volumes, daily production volumes, average realized prices and revenues for the three months ended March 31, 2016 and 2015:

	Three Months Ended March 31,		2016 Period Compared to 2015 Period	
	2016	2015	Increase (Decrease)	% Increase (Decrease)
Total production volumes -				
Crude oil (MBbls)	2,348	1,924	424	22 %
NGLs (MBbls)	414	318	96	30 %
Natural gas (MMcf)	6,373	5,234	1,139	22 %
Total barrels of oil equivalent (MBoe)	3,824	3,114	710	23 %
Daily production volumes by product -				
Crude oil (Bbls/d)	25,806	21,373	4,433	21 %
NGLs (Bbls/d)	4,547	3,529	1,018	29 %
Natural gas (Mcf/d)	70,033	58,159	11,874	20 %
Total barrels of oil equivalent (Boe/d)	42,025	34,595	7,430	21 %
Daily production volumes by region (Boe/d) -				
Eagle Ford	30,971	24,504	6,467	26 %
Niobrara	3,186	3,028	158	5 %
Marcellus	6,026	5,973	53	1 %
Utica	1,223	726	497	68 %
Delaware Basin and other	619	364	255	70 %
Total barrels of oil equivalent (Boe/d)	42,025	34,595	7,430	21 %
Average realized prices -				
Crude oil ($ per Bbl)	$28.96	$43.17	($14.21)	(33 %)
NGLs ($ per Bbl)	8.31	14.07	(5.76)	(41 %)
Natural gas ($ per Mcf)	1.54	2.39	(0.85)	(36 %)
Total average realized price ($ per Boe)	$21.25	$32.13	($10.88)	(34 %)
Revenues (In thousands) -				
Crude oil	$67,996	$83,058	($15,062)	(18 %)
NGLs	3,440	4,473	(1,033)	(23 %)
Natural gas	9,826	12,519	(2,693)	(22 %)
Total revenues	$81,262	$100,050	($18,788)	(19 %)

Revenues for the three months ended March 31, 2016 decreased 19% to $81.3 million from $100.1 million for the same period in 2015 due primarily to the decrease in average realized crude oil prices, partially offset by the increase in crude oil production. Production volumes for the three months ended March 31, 2016 and 2015 were 42,025 Boe/d and 34,595 Boe/d, respectively an increase of 21%. The increase in production from the first quarter of 2015 to the first quarter of 2016 was due primarily to increased production from new wells in the Eagle Ford, partially offset by normal production declines.

Lease operating expenses for the three months ended March 31, 2016 increased to $23.7 million ($6.19 per Boe) from $21.7 million ($6.97 per Boe) for the same period in 2015. The increase in lease operating expenses is due primarily to increased production from new wells in the Eagle Ford, partially offset by reduced costs due primarily to an increase in the volume of produced water being piped to disposal sites as opposed to trucked. The decrease in lease

operating expense per Boe is due primarily to the lower produced water disposal costs described above.
Production taxes decreased to $3.4 million (or 4.2% of revenues) for the three months ended March 31, 2016 from $4.0 million (or 4.0% of revenues) for the same period in 2015 as a result of the decrease in crude oil and natural gas revenues, partially offset by increased crude oil production from new wells in the Eagle Ford. The increase in production taxes as a percentage of

revenues for the three months ended March 31, 2016 as compared to the same period in 2015 is due primarily to a decreased proportion of total revenues attributable to Marcellus production, which is not subject to production taxes.
Ad valorem taxes decreased to $2.1 million for the three months ended March 31, 2016 from $3.0 million for the same period in 2015. The decrease in ad valorem taxes is due to a decrease in our annual estimate of ad valorem taxes due to lower tax valuations on our oil and gas properties, primarily as a result of the decrease in crude oil prices, partially offset by an increase attributable to new wells drilled in Eagle Ford in 2015.
Depreciation, depletion and amortization (“DD&A”) expense for the first quarter of 2016 decreased $14.3 million to $59.6 million ($15.58 per Boe) from the DD&A expense for the first quarter of 2015 of $73.9 million ($23.72 per Boe). The decrease in DD&A expense is attributable to the decrease in the DD&A rate per Boe, which is due primarily to the impairments recorded in the second half of 2015 and reductions in estimated future development costs that occurred throughout 2015. The components of our DD&A expense were as follows:

	Three Months Ended March 31,	
	2016	2015
	(In thousands)	
DD&A of proved oil and gas properties	$58,203	$72,972
Depreciation of other property and equipment	673	386
Amortization of other assets	373	256
Accretion of asset retirement obligations	328	257
Total DD&A	$59,577	$73,871

We recorded an after-tax impairment in the carrying value of proved oil and gas properties of $178.4 million ($274.4 million pre-tax) for the three months ended March 31, 2016 due primarily to a 9% decrease in the average realized price for sales of crude oil on the first calendar day of each month during the preceding 12-month period prior to March 31, 2016 as compared to the preceding 12-month period prior to December 31, 2015. There were no impairments of proved oil and gas properties for the three months ended March 31, 2015.
General and administrative expense decreased to $21.3 million for the three months ended March 31, 2016 from $31.6 million for the corresponding period in 2015. The decrease was primarily due to lower annual bonuses awarded in the first quarter of 2016 compared to the first quarter of 2015, reductions of accruals for estimated bonuses in the first quarter of 2016 as compared to the first quarter of 2015, and a decrease in stock-based compensation expense as a result of a smaller increase in the fair value of stock appreciation rights for the three months ended March 31, 2016 as compared to the same period of 2015.
The gain on derivatives, net for the three months ended March 31, 2016 amounted to $10.6 million due primarily to new crude oil and natural gas hedge positions executed during the first quarter of 2016 and the downward shift in the futures curve of forecasted commodity prices for crude oil from January 1, 2016 to March 31, 2016, partially offset by deferred premiums associated with the new crude oil hedge positions executed during the first quarter of 2016. The gain on derivatives, net for the three months ended March 31, 2015 amounted to $26.4 million due primarily to new crude oil hedge positions in the first quarter of 2015 and the downward shift in the futures curve of forecasted commodity prices for crude oil and natural gas during the first quarter of 2015.
Interest expense, net for the three months ended March 31, 2016 was $18.7 million as compared to $18.2 million for the same period in 2015. The slight increase was due primarily to the decrease in capitalized interest as a result of lower balances of unevaluated leasehold and seismic costs and exploratory well costs in the first quarter of 2016 as compared to the first quarter of 2015, partially offset by lower interest associated with the $650.0 million of 6.25% Senior Notes that were issued in April 2015 as compared to the interest associated with the $600.0 million of 8.625% Senior Notes that were redeemed in April 2015. The components of our interest expense, net were as follows:

	Three Months Ended March 31,	
	2016	2015
	(In thousands)	

Interest expense on Senior Notes	$21,455	$24,236
Interest expense on revolving credit facility	677	1,205
Amortization of debt issuance costs, premiums, and discounts	1,976	2,497
Other interest expense	254	6
Capitalized interest	(5,649)	(9,748)
Interest expense, net	$18,713	$18,196

The effective income tax rate for the first quarter of 2016 and 2015 was 0.0% and 34.8%, respectively. The variance from the U.S. Federal statutory rate of 35% for the three months ended March 31, 2016 was due primarily to a valuation allowance of $110.7 million that was recorded against our net deferred tax asset during the first quarter of 2016. The variance from the U.S. Federal statutory rate of 35% for the three months ended March 31, 2015 was due to the impact of state income taxes.

Liquidity and Capital Resources

2016 Capital Expenditure Plan and Funding Strategy. Our 2016 drilling and completion capital expenditure plan remains unchanged at $270.0 million to $290.0 million, while our 2016 leasehold and seismic capital expenditure plan is increased to $20.0 million from $15.0 million as a result of our outlook for continued bolt-on acquisitions. We currently intend to finance our 2016 capital expenditure plan primarily from the sources described below under "—Sources and Uses of Cash." Our capital program could vary depending upon various factors, including the availability and cost of drilling rigs, land and industry partner issues, our available cash flow and financing, success of drilling programs, weather delays, commodity prices, market conditions, the acquisition of leases with drilling commitments and other factors. Below is a summary of capital expenditures through March 31, 2016:

	Three Months Ended March 31, 2016 (In thousands)
Drilling and completion	
Eagle Ford	$72,417
Other	12,431
Total drilling and completion	84,848
Leasehold and seismic	5,911
Total (1)	$90,759

(1) Our capital expenditure plan and the capital expenditures included above exclude capitalized general and administrative expense, capitalized interest and capitalized asset retirement obligations.

Sources and Uses of Cash. Our primary use of cash is capital expenditures related to our drilling and completion programs and, to a lesser extent, our leasehold and seismic data acquisition programs. For the three months ended March 31, 2016, we funded our capital expenditures with cash provided by operations and borrowings under our revolving credit facility. Potential sources of future liquidity include the following:

- Cash provided by operations. Cash flows from operations are highly dependent on crude oil prices. As such, we hedge a portion of our forecasted production to mitigate the risk of a decline in crude oil prices.
- Borrowings under our revolving credit facility. As of April 29, 2016, we had $51.0 million of borrowings outstanding and $0.4 million in letters of credit outstanding under our revolving credit facility, which reduce the amounts available under our revolving credit facility. The amount we are able to borrow is subject to compliance with the financial covenants and other provisions of the credit agreement governing our revolving credit facility.
- Asset sales. In order to fund our capital expenditure plan, we may consider the sale of certain properties or assets that are not part of our core business or are no longer deemed essential to our future growth, provided we are able to sell such assets on terms that are acceptable to us. We are currently exploring sales of non-core properties.
- Securities offerings. As situations or conditions arise, we may choose to issue debt, equity or other securities to supplement our cash flows. However, we may not be able to obtain such financing on terms that are acceptable to us, or at all.
- Joint ventures. Joint ventures with third parties through which such third parties fund a portion of our exploration activities to earn an interest in our exploration acreage or purchase a portion of interests, or both.

Overview of Cash Flow Activities. Net cash provided by operating activities from continuing operations was $53.9 million and $73.5 million for the three months ended March 31, 2016 and 2015, respectively. The change was due primarily to a decrease in crude oil revenues, resulting primarily from lower crude oil prices in the first quarter of 2016 as compared to the first quarter of 2015, and an increase in working capital requirements, partially offset by a decrease in cash general and administrative expenses.

Net cash used in investing activities from continuing operations was $124.8 million and $211.9 million for the three months ended March 31, 2016 and 2015, respectively. The decrease was due primarily to a 40% reduction in our capital expenditures in 2016 as compared to 2015.

Net cash provided by financing activities from continuing operations was $30.2 million and $130.4 million for the three months ended March 31, 2016 and 2015, respectively. The decrease from 2015 to 2016 was due to the proceeds from the issuance of common stock in March 2015 as well as reduced borrowings on our revolving credit facility in the first quarter of 2016 as compared to the same period in 2015, partially offset by the payment of the deferred purchase payment in February 2015.

Liquidity/Cash Flow Outlook. Economic downturns may adversely affect our ability to access capital markets in the future. Cash flows from operations are primarily driven by crude oil production and prices. As a result of the significant decline in crude oil prices, our revenues, and thus our cash flows from operations have also declined. We currently believe that cash flows from operations and borrowings under our revolving credit facility provide adequate financial flexibility and will be sufficient to fund our immediate cash flow requirements.

- Revolving credit facility. As of April 29, 2016, our revolving credit facility had a borrowing base of $685.0 million, with $51.0 million of borrowings outstanding and $0.4 million in letters of credit issued, which reduce the amounts available under our revolving credit facility. The borrowing base under our revolving credit facility is affected by assumptions with respect to, among other things, future crude oil and natural gas prices, which are determined by the administrative agent of our revolving credit facility. Our borrowing base may decrease if our administrative agent reduces its expectations with respect to future crude oil and natural gas prices from those used to determine our existing borrowing base.

On May 3, 2016, we entered into an amendment to the credit agreement governing our revolving credit facility. See "—Financing Arrangements—Senior Secured Revolving Credit Facility" for further details of this amendment. As a result of our Spring 2016 borrowing base redetermination, our borrowing base was reduced from $685.0 million to $600.0 million. The amount we are able to borrow is subject to compliance with the financial covenants and other provisions of the credit agreement governing the revolving credit facility.

- Hedging. To manage our exposure to commodity price risk and to provide a level of certainty in the cash flows to support our drilling and completion capital expenditure program, we hedge a portion of our forecasted production.

In February 2015, we entered into derivative transactions offsetting our then existing crude oil derivative positions, which locked in $166.4 million of cash flows. As of March 31, 2016, the remaining locked in cash flows from the offsetting derivative transactions was approximately $29.1 million, of which approximately $26.4 million will be received during the remainder of 2016 and approximately $2.7 million will be received in the first quarter of 2017 as the applicable derivative contracts settle.

As of March 31, 2016, our derivative positions consisted of the following:

- crude oil costless collars for periods from April 2016 through December 2016,
- in-the-money fixed price crude oil swaps for periods from April 2016 through June 2017, and
- sold and purchased out-of-the-money crude oil and natural gas call options for periods from January 2017 through December 2020.

We have not entered into any new derivative positions subsequent to March 31, 2016. See "—Volatility of Crude Oil and Natural Gas Prices" for additional details of our derivative positions as of March 31, 2016.

If cash flows from operations and borrowings under our revolving credit facility and the other sources of cash described under "—Sources and Uses of Cash" are insufficient to fund the remainder of our 2016 capital expenditure plans, we may need to reduce our capital expenditure plans or seek other financing alternatives. We may not be able to obtain financing needed in the future on terms that would be acceptable to us, or at all. If we cannot obtain adequate financing, we may be required to limit or defer all or a portion of our remaining 2016 capital expenditure plans, thereby potentially adversely affecting the recoverability and ultimate value of our oil and gas properties. Subject in each case to then existing market conditions and to our then expected liquidity needs, among other factors, we may use a portion of our cash flows from operations, proceeds from asset sales, securities offerings or borrowings to reduce debt prior to scheduled maturities through debt repurchases, either in the open market or in privately negotiated transactions, through debt redemptions or tender offers, or through repayments of bank borrowings.

Contractual Obligations

The following table sets forth estimates of our contractual obligations as of March 31, 2016 (in thousands):

	April - December 2016	2017	2018	2019	2020	2021 and Thereafter	Total
Long-term debt (1)	$—	$—	$30,550	$—	$600,000	$654,425	$1,284,975
Cash interest on senior notes and other long-term debt (2)	63,319	85,819	85,819	85,819	85,819	102,998	509,593
Cash interest and commitment fees on revolving credit facility (3)	2,342	3,075	1,559	—	—	—	6,976
Capital leases	1,392	1,856	1,823	1,800	1,050	—	7,921
Operating leases	3,185	4,186	4,248	4,357	4,450	6,304	26,730
Drilling rig contracts (4)	17,505	20,513	3,957	—	—	—	41,975
Pipeline volume commitments	6,920	9,250	8,866	7,240	4,542	2,804	39,622
Asset retirement obligations and other (5)	1,767	1,850	—	28	479	15,946	20,070
Total Contractual Obligations	$96,430	$126,549	$136,822	$99,244	$696,340	$782,477	$1,937,862

(1) Long-term debt consists of the principal amounts of the 7.50% Senior Notes due 2020, the 6.25% Senior Notes due 2023, other long-term debt due 2028, and borrowings outstanding under our revolving credit facility which matures in 2018.

(2) Cash interest on senior notes and other long-term debt includes cash payments for interest on the 7.50% Senior Notes due 2020, the 6.25% Senior Notes due 2023 and other long-term debt due 2028.

(3) Cash payments for interest on our revolving credit facility were calculated using the weighted average interest rate of the outstanding borrowings under the revolving credit facility as of March 31, 2016 of 2.01%. Commitment fees on our revolving credit facility were calculated based on the unused portion of lender commitments as of March 31, 2016, at the commitment fee rate of 0.375%.

(4) Drilling rig contracts represent gross contractual obligations and accordingly, other joint owners in the properties operated by us will generally be billed for their working interest share of such costs.

(5) Asset retirement obligations and other are based on estimates and assumptions that affect the reported amounts as of March 31, 2016. Certain of such estimates and assumptions are inherently unpredictable and will differ from actual results.

Financing Arrangements

Senior Secured Revolving Credit Facility

We have a senior secured revolving credit facility with a syndicate of banks that, as of March 31, 2016, had a borrowing base of $685.0 million, with $30.6 million of borrowings outstanding with a weighted average interest rate of 2.01% and $0.6 million in letters of credit outstanding. The credit agreement governing our senior secured revolving credit facility provides for interest-only payments until July 2, 2018, when the credit agreement matures and any outstanding borrowings are due. The borrowing base under our credit agreement is subject to regular redeterminations in the Spring and Fall of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base.

Our obligations under the credit agreement are guaranteed by our material domestic subsidiaries and are secured by liens on substantially all of our assets, including a mortgage lien on oil and gas properties having at least 80% of the proved reserve value of the oil and gas properties included in the determination of the borrowing base.

As of March 31, 2016, amounts outstanding under the credit agreement bear interest at our option at either (i) a base rate for a base rate loan plus the margin set forth in the table below, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.50% and the adjusted LIBO rate plus 1.00%, or (ii) an adjusted LIBO rate for a Eurodollar loan plus the margin set forth in the table below. We also incur commitment fees as set forth in the table below on the unused portion of lender commitments, which are included as a component of interest expense.

Ratio of Outstanding Borrowings and Letters of Credit to Lender Commitments	Applicable Margin for	Applicable Margin for	Commitment Fee

	Base Rate Loans	Eurodollar Loans	
Less than 25%	0.50%	1.50%	0.375%
Greater than or equal to 25% but less than 50%	0.75%	1.75%	0.375%
Greater than or equal to 50% but less than 75%	1.00%	2.00%	0.500%
Greater than or equal to 75% but less than 90%	1.25%	2.25%	0.500%
Greater than or equal to 90%	1.50%	2.50%	0.500%

As of March 31, 2016, we were subject to certain covenants under the terms of the credit agreement, which include the maintenance of the following financial covenants determined as of the last day of each quarter: (1) a ratio of Total Debt to EBITDA of not more than 4.75 to 1.00 through December 31, 2016, reducing to 4.375 to 1.00 through December 31, 2017, and to 4.00 to 1.00 thereafter; and (2) a Current Ratio of not less than 1.00 to 1.00. As defined in the credit agreement, Total Debt excludes debt discounts, premiums, and debt issuance costs and is net of cash and cash equivalents, EBITDA includes the last four quarters after giving pro forma effect to EBITDA for material acquisitions and dispositions of oil and gas properties, and the Current Ratio includes an add back of the unused portion of lender commitments. As of March 31, 2016, the ratio of Total Debt to EBITDA was 2.89 to 1.00 and the Current Ratio was 4.14 to 1.00. Because the financial covenants are determined as of the last day of each quarter, the ratios can fluctuate significantly period to period as the amounts outstanding under the credit agreement are dependent on the timing of cash flows from operations, capital expenditures, acquisitions and dispositions of oil and gas properties and securities offerings.

Our revolving credit facility also places restrictions on us and certain of our subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of our common stock, redemptions of senior notes, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

The credit agreement is subject to customary events of default, including in connection with a change in control. If an event of default occurs and is continuing, the lenders may elect to accelerate amounts due under the credit agreement (except in the case of a bankruptcy event of default, in which case such amounts will automatically become due and payable).

On May 3, 2016, we entered into the Eighth Amendment to, among other things (i) replace the Total Debt to EBITDA ratio covenant with a Total Secured Debt to EBITDA ratio covenant that requires such ratio not to exceed 2.00 to 1.00, (ii) add a covenant requiring a minimum EBITDA to Interest Expense ratio of at least 2.50 to 1.00, (iii) reduce the Borrowing Base under the credit facility from $685.0 million to $600.0 million until the next redetermination thereof, (iv) increase the required mortgage coverage on the total value of the oil and gas properties included in our most recent reserve report from 80% to 90%, (v) require that our deposit accounts and securities accounts (subject to certain exclusions) become subject to control agreements, (vi) limit the amount of additional senior notes that can be issued by us to $400.0 million, (vii) restrict us from making borrowings under the credit facility if we have or, after giving effect to the borrowing, will have a Consolidated Cash Balance in excess of $50.0 million, (viii) require mandatory prepayment of borrowings to the extent the Consolidated Cash Balance exceeds $50.0 million if either (a) our ratio of Total Debt to EBITDA exceeds 3.50 to 1.00 or (b) the availability under the credit facility is equal to or less than 20% of the then effective Borrowing Base, (ix) increase the margin on all loans by 0.50% and (x) increase the commitment fee from 0.375% to 0.50% when utilization of lender commitments is less than 50%.

Each of the capitalized terms used but not defined in this section of our quarterly report, "—Senior Secured Revolving Credit Facility," shall have the meaning given to such terms in the credit agreement governing the Company's revolving credit facility.

Critical Accounting Policies

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods reported. Certain of such estimates and assumptions are inherently unpredictable and will differ from actual results. We have identified the following critical accounting policies and estimates used in the preparation of our financial statements: use of estimates, oil and gas properties, oil and gas reserve estimates, derivative instruments, income taxes and commitments and contingencies. These policies and estimates are described in "Note 2. Summary of Significant Accounting Policies" of the Notes to Consolidated Financial Statements in our 2015 Annual Report. We evaluate subsequent events through the date the financial statements are issued.

Full Cost Ceiling Test Impairment

Capitalized costs, less accumulated amortization and related deferred income taxes, are limited to the "cost center ceiling" equal to (i) the sum of (A) the present value of estimated future net revenues from proved oil and gas reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves computed using a discount factor of 10%, (B) the costs of unproved properties not being amortized, and (C) the lower of cost or estimated fair value of unproved properties included in the costs being amortized; less (ii) related income tax effects.

If the net capitalized costs exceed the cost center ceiling, the excess is recognized as an impairment of proved oil and gas properties. An impairment recognized in one period may not be reversed in a subsequent period even if higher crude oil and natural gas prices in the future increase the cost center ceiling applicable to the subsequent period.
The estimated future net revenues used in the cost center ceiling are calculated using the average realized prices for sales of crude oil and natural gas on the first calendar day of each month during the preceding 12-month period prior to the end of the current reporting period ("12-Month Average Realized Price"). Prices are held constant indefinitely and are not changed except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts. Prices do not include the impact of derivative instruments because we elected not to meet the criteria to qualify its derivative instruments for hedge accounting treatment.

During the first quarter of 2016, we recorded an after-tax impairment in the carrying value of proved oil and gas properties of $178.4 million ($274.4 million pre-tax). The impairment was due primarily to a 9% decrease in the 12-Month Average Realized Price of crude oil from $47.24 per barrel as of December 31, 2015 to $43.14 per barrel as of March 31, 2016. The price decrease was primarily responsible for a negative revision to our proved reserves for the first quarter of 2016 totaling 5.0 MMBoe (3% of December 31, 2015 proved reserves), of which 2.1 MMBoe was attributable to proved developed reserves of producing wells with shorter economic lives and 2.9 MMBoe was attributable to proved undeveloped reserves of locations that were no longer economic and removed from proved reserves. Approximately 90% of the removed reserves relate to locations scheduled to be developed in 2017, 2018 and 2019. Accordingly, we do not expect any significant changes to our development plans in the near term as a result of these revisions to proved reserves.

The table below presents various pricing scenarios to demonstrate the sensitivity of our March 31, 2016 cost center ceiling to changes in the 12-month average benchmark crude oil and natural gas prices underlying the 12-Month Average Realized Price. The sensitivity analysis is as of March 31, 2016 and, accordingly, does not consider the results of drilling and completion activity, production, changes in oil and gas prices, and changes in development and operating costs occurring subsequent to March 31, 2016 which may require revisions to estimates of proved reserves.

	12-Month Average Realized Prices		Excess (deficit) of cost center ceiling over net capitalized costs (after-tax)	Increase (decrease) of cost center ceiling over net capitalized costs (after-tax)
Full Cost Pool Scenarios	Crude Oil ($/Bbl)	Natural Gas ($/Mcf)	(In millions)	(In millions)
March 31, 2016 Actual	$43.14	$1.68	$—	
Crude Oil and Natural Gas Price Sensitivity				
Crude Oil and Natural Gas +10%	$47.75	$1.92	$200	$200
Crude Oil and Natural Gas -10%	$38.51	$1.45	($200)	($200)
Crude Oil Price Sensitivity				
Crude Oil +10%	$47.75	$1.68	$180	$180
Crude Oil -10%	$38.51	$1.68	($180)	($180)
Natural Gas Price Sensitivity				
Natural Gas +10%	$43.14	$1.92	$20	$20
Natural Gas -10%	$43.14	$1.45	($20)	($20)

For the second quarter of 2016, we currently estimate an after-tax impairment in the carrying value of proved oil and gas properties of approximately $175.0 million to $275.0 million ($269.2 million to $423.1 million pre-tax). This estimated impairment is primarily due to a forecasted 9% decrease in the 12-Month Average Realized Price of crude oil from $43.14 per barrel as of March 31, 2016 to an estimated $39.21 per barrel as of June 30, 2016 which is based on the average realized price for sales of crude oil on the first calendar day of each month for the first 11 months and an estimate for the twelfth month based on a quoted forward price. We estimate that this price decrease will result in a negative revision to our proved reserves for the second quarter of 2016 totaling 5.5 MMBoe (3% of December 31, 2015 proved reserves), of which we estimate 2.5 MMBoe to be attributable to proved developed reserves of producing wells with shorter economic lives and 3.0 MMBoe to be attributable to proved undeveloped reserves of locations that will no longer be economic and removed from proved reserves. All of the removed reserves relate to locations scheduled to be developed in 2017, 2018 and 2019. Accordingly, we do not expect any changes to our development

plans in the near term as a result of these estimated revisions to proved reserves. Further declines in the 12-Month Average Realized Price of crude oil in subsequent quarters may result in additional negative revisions to proved reserves and additional impairments in the carrying value of proved oil and gas properties.
The key factors and assumptions we used to estimate proved reserves and impairments for the second quarter of 2016 include planned drilling and completion activity, forecasted production, oil and gas price differentials and development and production costs. Given the uncertainty associated with these key factors and assumptions, these estimates should not necessarily be construed as indicative of our future results.

Income Taxes

Income taxes are recognized based on earnings reported for tax return purposes in addition to a provision for deferred income taxes. Deferred income taxes are recognized at the end of each reporting period for the future tax consequences of cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in our financial statements based on existing tax laws and enacted statutory tax rates applicable to the periods in which the temporary differences are expected to affect taxable income. We assess the realizability of our deferred tax assets each period by considering whether it is more likely than not that all or a portion of the deferred tax assets will not be realized. We consider all available evidence (both positive and negative) when determining whether a valuation allowance is required. We evaluated possible sources of taxable income that may be available to realize the benefit of deferred tax assets, including projected future taxable income, the reversal of existing temporary differences, taxable income in carryback years and available tax planning strategies in making this assessment.

A significant item of objective negative evidence considered was the cumulative historical three year pre-tax loss and a net deferred tax asset position at March 31, 2016, driven primarily by the full cost ceiling test impairments recognized during the second half of 2015 and the first quarter of 2016, which limits the ability to consider other subjective evidence such as our anticipated future growth. In addition, we also expect to recognize an additional impairment of our oil and gas properties during the second quarter of 2016. We also have estimated U.S. federal net operating loss carryforwards of $445.4 million as of March 31, 2016. As a result of the historical and projected future losses, we concluded that it is more likely than not that the deferred tax assets will not be realized and recorded an additional valuation allowance against the net deferred tax asset as of March 31, 2016 of $110.7 million, reducing the net deferred tax asset to zero.

We will continue to evaluate whether the valuation allowance is needed in future reporting periods. The valuation allowance will remain until we can determine that the net deferred tax assets are more likely than not to be realized. Future events or new evidence which may lead us to conclude that it is more likely than not our net deferred tax assets will be realized include, but are not limited to, cumulative historical pre-tax earnings, improvements in crude oil prices, and taxable events that could result from one or more transactions. The valuation allowance does not impact future utilization of the underlying tax attributes. As long as we conclude that the valuation allowance against our net deferred tax assets is necessary, we likely will not have any additional income tax expense or benefit. As a result of the anticipated impairment in the carrying value of oil and gas properties in the second quarter of 2016, we expect to record an additional valuation allowance against any deferred tax asset generated by such impairment.

We classify interest and penalties associated with income taxes as interest expense. We follow the tax law ordering approach to determine the sequence in which deferred tax assets and other tax attributes are utilized.

Recent Accounting Pronouncements

See "Note 2. Summary of Significant Accounting Policies" for discussion of the recent accounting pronouncements issued by the Financial Accounting Standards Board.

Volatility of Crude Oil and Natural Gas Prices

Our revenues, future rate of growth, results of operations, financial position and ability to borrow funds or obtain additional capital are substantially dependent upon prevailing prices of crude oil and natural gas, which are affected by changes in market demand, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors.

We review the carrying value of our oil and gas properties on a quarterly basis using the full cost method of accounting. See "—Critical Accounting Policies—Full Cost Ceiling Test Impairment" and "Note 3. Property and Equipment, Net" for additional details.

We use commodity derivative instruments to reduce our exposure to commodity price volatility for a substantial, but varying, portion of our forecasted crude oil and natural gas production and thereby achieve a more predictable level of cash flows to support our drilling and completion capital expenditure program. We do not enter into derivative instruments for speculative or trading purposes. As of March 31, 2016, our commodity derivative instruments consisted of fixed price swaps, costless collars, and purchased and sold call options, which are described below:

Fixed Price Swaps: We receive a fixed price and pay a variable market price to the counterparties over specified periods for contracted volumes.

Costless Collars: A collar is a combination of options including a purchased put option (fixed floor price) and a sold call option (fixed ceiling price) and allows us to benefit from increases in commodity prices up to the fixed ceiling price and protect us from decreases in commodity prices below the fixed floor price. At settlement, if the market price is below the fixed floor price or is above the fixed ceiling price, we receive the fixed price and pay the market price. If the market price is between the fixed floor price and fixed ceiling price, no payments are due from either party. These contracts were executed contemporaneously with the same counterparties and were premium neutral such that no premiums were paid to or received from the counterparties.

Sold Call Options: These contracts give the counterparties the right, but not the obligation, to buy contracted volumes from us over specified periods and prices in the future. At settlement, if the market price exceeds the fixed price of the call option, we pay the counterparty the excess. If the market price settles below the fixed price of the call option, no payment is due from either party.
Purchased Call Options: These contracts give us the right, but not the obligation, to buy contracted volumes from the counterparties over specified periods and prices in the future. At settlement, if the market price exceeds the fixed price of the call option, the counterparties pay us the excess. If the market price settles below the fixed price of the call option, no payment is due from either party. We net our purchased call options with our sold call options for the years 2018 through 2020 in the open crude oil derivative positions table below.
The following sets forth a summary of our open crude oil derivative positions at average NYMEX prices as of March 31, 2016:

Period	Type of Contract	Volumes (in Bbls/d)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)
April - December 2016	Fixed Price Swaps	9,750	$60.03	
April - December 2016	Costless Collars	4,000	$50.00	$76.50
January - June 2017	Fixed Price Swaps	12,000	$50.13	
FY 2018	Sold Call Options	2,488		$60.00
FY 2018	Sold Call Options	900		$75.00
FY 2019	Sold Call Options	2,975		$62.50
FY 2019	Sold Call Options	900		$77.50
FY 2020	Sold Call Options	3,675		$65.00
FY 2020	Sold Call Options	900		$80.00

The following sets forth a summary of the Company’s open natural gas derivative positions at average NYMEX prices as of March 31, 2016:

Period	Type of Contract	Natural Gas Volumes (in MMBtu/d)	Weighted Average Ceiling Price ($/MMBtu)
FY 2017	Sold Call Options	33,000	$3.00
FY 2018	Sold Call Options	33,000	$3.25
FY 2019	Sold Call Options	33,000	$3.25
FY 2020	Sold Call Options	33,000	$3.50

In February 2015, we entered into derivative transactions offsetting our then existing crude oil derivative positions covering the periods from March 2015 through December 2016. As a result of the offsetting derivative transactions, we locked in $166.4 million of cash flows, of which $18.3 million was received due to contract settlements during the three months ended March 31, 2016, and is included in the gain on derivatives, net in the consolidated statements of operations. As of March 31, 2016, the fair value of the remaining locked in cash flows is $29.1 million, all of which is a current asset and is classified as “Derivative assets” in the consolidated balance sheets. The derivative assets associated with the offsetting derivative transactions are not subject to price risk and the locked in cash flows will be received as the applicable contracts settle. The offsetting derivative transactions are not included in the table above.
In February 2016, we sold out-of-the-money natural gas call options for the years 2017 through 2020 and used the associated premium value to obtain a higher weighted average fixed price of $50.27 per Bbl on 6,000 Bbls/d of newly executed crude oil fixed price swaps for the first half of 2017. These out-of-the-money natural gas call options and in-the-money crude oil fixed price swaps were executed contemporaneously with the same counterparty, therefore, no cash premiums were paid to or received from the counterparty as the premium value associated with the natural gas call options was immediately applied to the crude oil fixed price swaps.

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In March 2016, we sold 6,000 Bbls/d of in-the-money crude oil fixed price swaps for the first half of the year 2017 at a weighted average fixed price of $50.00 per Bbl. In order to obtain this higher weighted average fixed price, we incurred net premiums of approximately $5.6 million which we will pay in two equal payments at the end of the second and third quarters of 2016. In addition to these premiums, during the fourth quarter of 2015, we incurred net premiums of approximately $5.0 million related to the simultaneous purchase and sale of out-of-the-money crude oil call options, the payment of which is deferred until settlement. For further discussion of this fourth quarter of 2015 transaction, see "Note 13. Derivative Instruments" of the Notes to Consolidated Financial Statements in our 2015 Annual Report.

For the three months ended March 31, 2016 and 2015, we recorded in the consolidated statements of operations a gain on derivatives, net of $10.6 million and $26.4 million, respectively.

We typically have numerous hedge positions that span several time periods and often result in both fair value asset and liability positions held with that counterparty, which positions are all offset to a single fair value asset or liability at the end of each reporting period, including the deferred premiums associated with our hedge positions. We net our derivative instrument fair values executed with the same counterparty pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. The fair value of derivative instruments where we are in a net asset position with our counterparties as of March 31, 2016 and December 31, 2015 totaled $78.9 million and $119.6 million, respectively, and is summarized by counterparty in the table below:

Counterparty	March 31, 2016		December 31, 2015	
Societe Generale	32	%	37	%
Wells Fargo	32	%	35	%
Citibank	19	%	13	%
Regions	9	%	9	%
Union Bank	6	%	5	%
Capital One	2	%	1	%
Total	100	%	100	%

The counterparties to our derivative instruments are also lenders under our credit agreement which allows us to satisfy any need for margin obligations associated with derivative liabilities with the collateral securing the credit agreement, thus eliminating the need for independent collateral posting.

Because each of the counterparties have investment grade credit ratings, we believe we do not have significant credit risk and accordingly do not currently require our counterparties to post collateral to support the net asset positions of our derivative instruments. As such, we are exposed to credit risk to the extent of nonperformance by the counterparties to our derivative instruments. Although we do not currently anticipate such nonperformance, we continue to monitor the credit ratings of our counterparties.

Forward-Looking Statements

This quarterly report contains statements concerning our intentions, expectations, projections, assessments of risks, estimations, beliefs, plans or predictions for the future, objectives, goals, strategies, future events or performance and underlying assumptions and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. These forward-looking statements include, among others, statements regarding:

- our growth strategies;
- our ability to explore for and develop oil and gas resources successfully and economically;
- our estimates and forecasts of the timing, number, profitability and other results of wells we expect to drill and other exploration activities;
- our estimates regarding timing and levels of production;
- changes in working capital requirements, reserves, and acreage;
- commodity hedging activities and the impact on our average realized prices;
- anticipated trends in our business;
- availability of pipeline connections and water disposal on economic terms;

- effects of competition on us;

- our future results of operations;
- profitability of drilling locations;
- our liquidity and our ability to finance our exploration and development activities, including accessibility of borrowings under our revolving credit facility, our borrowing base, and the result of any borrowing base redetermination;
- our planned expenditures, prospects and capital expenditure plan;
- future market conditions in the oil and gas industry;
- our ability to make, integrate and develop acquisitions and realize any expected benefits or effects of completed acquisitions;
- the benefits, effects, availability of and results of new and existing joint ventures and sales transactions;
- our ability to maintain a sound financial position;
- receipt of receivables, drilling carry and proceeds from sales;
- our ability to complete planned transactions on desirable terms; and
- the impact of governmental regulation, taxes, market changes and world events.

You generally can identify our forward-looking statements by the words “anticipate,” “believe,” budgeted,” “continue,” “could,” “estimate,” “expect,” “forecast,” “goal,” “intend,” “may,” “objective,” “plan,” “potential,” “predict,” “projection,” “sc other similar words. Such statements rely on assumptions and involve risks and uncertainties, many of which are beyond our control, including, but not limited to, those relating to a worldwide economic downturn, availability of financing, our dependence on our exploratory drilling activities, the volatility of and changes in crude oil and natural gas prices, the need to replace reserves depleted by production, operating risks of crude oil and natural gas operations, our dependence on our key personnel, factors that affect our ability to manage our growth and achieve our business strategy, results, delays and uncertainties that may be encountered in drilling, development or production, interpretations and impact of oil and gas reserve estimation and disclosure requirements, activities and approvals of our partners and parties with whom we have alliances, technological changes, capital requirements, the timing and amount of borrowing base determinations (including determinations by lenders) and availability under our revolving credit facility, evaluations of us by lenders under our revolving credit facility, other actions by lenders, the potential impact of government regulations, including current and proposed legislation and regulations related to hydraulic fracturing, crude oil and natural gas drilling, air emissions and climate change, regulatory determinations, litigation, competition, the uncertainty of reserve information and future net revenue estimates, acquisition risks, availability of equipment and crews, actions by midstream and other industry participants, weather, our ability to obtain permits and licenses, the results of audits and assessments, the failure to obtain certain bank and lease consents, the existence and resolution of title defects, new taxes and impact fees, delays, costs and difficulties relating to our joint ventures, actions by joint venture parties, results of exploration activities, the availability and completion of land acquisitions, costs of oilfield services, completion and connection of wells, and other factors detailed in this quarterly report.

We have based our forward-looking statements on our management’s beliefs and assumptions based on information available to our management at the time the statements are made. We caution you that assumptions, beliefs, expectations, intentions and projections about future events may and often do vary materially from actual results. Therefore, we cannot assure you that actual results will not differ materially from those expressed or implied by our forward-looking statements.

Some of the factors that could cause actual results to differ from those expressed or implied in forward-looking statements are described under Part I, “Item 1A. Risk Factors” and other sections of our 2015 Annual Report and in our other filings with the SEC, including this quarterly report. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by reference to these risks and uncertainties. You should not place undue reliance on our forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement, and, except as required by law, we undertake no duty to update or revise any forward-looking statement.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

For information regarding our exposure to certain market risks, see “Item 7A. Quantitative and Qualitative Disclosures about Market Risk” of our 2015 Annual Report. Except as disclosed in this report, there have been no material changes from the disclosure made in our 2015 Annual Report regarding our exposure to certain market risks.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. Our Chief Executive Officer and Chief Financial Officer performed an evaluation of our disclosure controls and procedures, which have been designed to provide reasonable assurance that the information required to be disclosed by the Company in the reports it files or submits under the Exchange Act is accumulated and communicated to the Company's management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure. They concluded that the controls and procedures were effective as of March 31, 2016 to provide reasonable assurance that the information required to be disclosed by the Company in reports it files under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. While our disclosure controls and procedures provide reasonable assurance that the appropriate information will be available on a timely basis, this assurance is subject to limitations inherent in any control system, no matter how well it may be designed or administered.

Changes in Internal Controls. There was no change in our internal control over financial reporting during the quarter ended March 31, 2016 that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

From time to time, the Company is party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not currently expect these matters to have a materially adverse effect on the financial position or results of operations of the Company.

Item 1A. Risk Factors

There were no material changes to the factors discussed in "Part I. Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2015.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

The following exhibits are required by Item 601 of Regulation S-K and are filed as part of this report:

Exhibit Number		Exhibit Description
10.1	–	Eighth Amendment to Credit Agreement, dated as of May 3, 2016, among Carrizo Oil & Gas, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lender parties thereto (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 4, 2016 (File No. 000-29187-87)).
*31.1	–	CEO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	–	CFO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	–	CEO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	–	CFO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101	–	Interactive Data Files

* Filed herewith.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

Carrizo Oil & Gas, Inc.
(Registrant)

Date: May 5, 2016 By: /s/ David L. Pitts
Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: May 5, 2016 By: /s/ Gregory F. Conaway
Vice President and Chief Accounting Officer
(Principal Accounting Officer)