CARRIZO OIL & GAS INC
Form 10-Q
November 04, 2015

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 September 30, 2015

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 (State or other jurisdiction of incorporation or organization)	76-0415919 (IRS Employer Identification No.)
500 Dallas Street, Suite 2300, Houston, Texas (Address of principal executive offices)	77002 (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 October 30, 2015 was 58,326,360.

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

	September 30, 2015	December 31, 2014
Assets		
Current assets		
Cash and cash equivalents	$2,004	$10,838
Accounts receivable, net	57,305	92,946
Derivative assets	108,882	171,101
Other current assets	3,085	3,736
Total current assets	171,276	278,621
Property and equipment		
Oil and gas properties, full cost method		
Proved properties, net	1,654,133	2,086,727
Unproved properties, not being amortized	403,513	535,197
Other property and equipment, net	13,373	7,329
Total property and equipment, net	2,071,019	2,629,253
Deferred income taxes	38,807	—
Derivative assets	6,457	43,684
Debt issuance costs	25,275	25,403
Other assets	5,453	4,515
Total Assets	$2,318,287	$2,981,476
Liabilities and Shareholders’ Equity		
Current liabilities		
Accounts payable	$50,650	$106,819
Revenues and royalties payable	69,899	66,954
Accrued capital expenditures	69,463	106,149
Accrued interest	19,359	21,149
Liabilities of discontinued operations	3,234	4,405
Deferred income taxes	38,807	61,258
Other current liabilities	50,671	57,570
Total current liabilities	302,083	424,304
Long-term debt	1,412,221	1,351,346
Liabilities of discontinued operations	2,037	8,394
Deferred income taxes	—	77,349
Asset retirement obligations	14,489	12,187
Other liabilities	9,077	4,455
Total liabilities	1,739,907	1,878,035
Commitments and contingencies		
Shareholders’ equity		
Common stock, $0.01 par value, 90,000,000 shares authorized; 51,971,797 issued and outstanding as of September 30, 2015 and 46,127,924 issued and outstanding as of December 31, 2014	520	461
Additional paid-in capital	1,165,305	915,436
Retained earnings (Accumulated deficit)	(587,445)	187,544

Total shareholders’ equity	578,380	1,103,441
Total Liabilities and Shareholders’ Equity	$2,318,287	$2,981,476

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 September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Revenues				
Crude oil	$95,237	$173,277	$289,552	$469,601
Natural gas liquids	3,330	7,798	11,602	19,669
Natural gas	7,670	15,150	28,627	57,642
Total revenues	106,237	196,225	329,781	546,912
Costs and Expenses				
Lease operating	22,213	21,019	67,304	51,002
Production taxes	4,264	8,393	13,313	22,666
Ad valorem taxes	2,256	2,235	7,012	5,569
Depreciation, depletion and amortization	81,256	83,572	234,458	228,912
General and administrative	4,207	9,538	54,879	65,481
(Gain) loss on derivatives, net	(28,752)	(71,783)	(42,596)	(11,153)
Interest expense, net	16,208	12,201	51,403	36,557
Impairment of oil and gas properties	812,752	—	812,752	—
Loss on extinguishment of debt	—	—	38,137	—
Other expense, net	3,516	549	10,789	1,536
Total costs and expenses	917,920	65,724	1,247,451	400,570
Income (Loss) From Continuing Operations Before Income Taxes	(811,683)	130,501	(917,670)	146,342
Income tax (expense) benefit	102,915	(47,504)	140,456	(53,510)
Income (Loss) From Continuing Operations	(708,768)	82,997	(777,214)	92,832
Income (Loss) From Discontinued Operations, Net of Income Taxes	1,121	792	2,225	(748)
Net Income (Loss)	($707,647)	$83,789	($774,989)	$92,084
Net Income (Loss) Per Common Share - Basic				
Income (loss) from continuing operations	($13.75)	$1.83	($15.62)	$2.05
Income (loss) from discontinued operations, net of income taxes	0.02	0.02	0.04	(0.02)
Net income (loss)	($13.73)	$1.85	($15.58)	$2.03
Net Income (Loss) Per Common Share - Diluted				
Income (loss) from continuing operations	($13.75)	$1.80	($15.62)	$2.01
Income (loss) from discontinued operations, net of income taxes	0.02	0.02	0.04	(0.01)
Net income (loss)	($13.73)	$1.82	($15.58)	$2.00
Weighted Average Common Shares Outstanding				
Basic	51,543	45,257	49,742	45,277
Diluted	51,543	46,029	49,742	46,109

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

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

	Nine Months Ended September 30, 2015	2014
Cash Flows From Operating Activities		
Net income (loss)	($774,989)	$92,084
(Income) loss from discontinued operations, net of income taxes	(2,225)	748
Adjustments to reconcile income (loss) from continuing operations to net cash provided by operating activities from continuing operations		
Depreciation, depletion and amortization	234,458	228,912
Impairment of oil and gas properties	812,752	—
(Gain) loss on derivatives, net	(42,596)	(11,153)
Cash received (paid) for derivative settlements, net	141,909	(25,499)
Loss on extinguishment of debt	38,137	—
Stock-based compensation, net	9,203	28,209
Deferred income taxes	(140,538)	48,908
Non-cash interest expense, net	3,564	2,021
Other, net	4,554	(1,705)
Changes in operating assets and liabilities-		
Accounts receivable	27,395	(1,767)
Accounts payable	(18,115)	33,024
Accrued liabilities	(5,614)	(771)
Other, net	(3,676)	(4,324)
Net cash provided by operating activities from continuing operations	284,219	388,687
Net cash used in operating activities from discontinued operations	(1,247)	(1,162)
Net cash provided by operating activities	282,972	387,525
Cash Flows From Investing Activities		
Capital expenditures - oil and gas properties	(541,616)	(665,517)
Capital expenditures - other property and equipment	(1,270)	(569)
Proceeds from sales of oil and gas properties, net	7,934	10,487
Other, net	(4,120)	1,418
Net cash used in investing activities from continuing operations	(539,072)	(654,181)
Net cash used in investing activities from discontinued operations	(2,125)	(6,773)
Net cash used in investing activities	(541,197)	(660,954)
Cash Flows From Financing Activities		
Issuance of senior notes	650,000	—
Tender and redemption of senior notes	(626,681)	—
Payment of deferred purchase payment	(150,000)	—
Borrowings under credit agreement	1,045,521	646,000
Repayments of borrowings under credit agreement	(889,031)	(527,000)
Payments of debt issuance costs	(11,665)	(594)
Sale of common stock, net of offering costs	231,316	—
Excess tax benefits from stock-based compensation	—	4,602
Proceeds from stock options exercised	46	143
Other, net	(115)	—
Net cash provided by financing activities from continuing operations	249,391	123,151
Net cash provided by financing activities from discontinued operations	—	—

Net cash provided by financing activities	249,391	123,151
Net Decrease in Cash and Cash Equivalents	(8,834)	(150,278)
Cash and Cash Equivalents, Beginning of Period	10,838	157,439
Cash and Cash Equivalents, End of Period	$2,004	$7,161

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

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 Utica Shale in Ohio, the Niobrara Formation in Colorado, 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, 2014 ("2014 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 2014 Annual Report. There have been no changes to the Company's significant accounting policies since December 31, 2014.

Recent Accounting Pronouncements

In April 2015, the Financial Accounting Standards Board ("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 addresses the presentation or subsequent measurement of debt issuance costs related to line-of-credit arrangements, given the absence of authoritative guidance within Update 2015-03 for debt issuance costs related to line-of-credit arrangements. Under Update 2015-15, debt issuance costs associated with line-of-credit agreements may 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, Update 2015-03 and Update 2015-15 are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015 and applied retrospectively with early adoption permitted. The adoption of Update 2015-03 and Update 2015-15 will not have an impact on the Company's consolidated financial statements, other than balance sheet reclassifications.

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. In April 2015, the FASB proposed to delay the effective date one year. This proposal was approved in July 2015 and as such, Update 2014-09 is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period for public entities. The Company is currently evaluating the impact of the adoption of Update 2014-09 on its consolidated financial statements.

3. Discontinued Operations

On February 22, 2013, the Company closed on the sale of Carrizo UK Huntington Ltd, a wholly owned subsidiary of the Company ("Carrizo UK"), and all of its interest in the Huntington Field discovery, including a 15% non-operated working interest and certain overriding royalty interests, to a subsidiary of Iona Energy Inc. ("Iona Energy") for an agreed-upon price of $184.0 million, including the assumption and repayment by Iona Energy of the $55.0 million of borrowings outstanding under Carrizo UK's senior secured multicurrency credit facility as of the closing date. The liabilities, results of operations and cash flows associated with Carrizo UK have been classified as discontinued operations in the consolidated financial statements. The liabilities of discontinued operations of $5.3 million and $12.8 million as of September 30, 2015 and December 31, 2014, respectively, relate to an accrual for estimated future obligations related to the sale.

The following table summarizes the amounts included in income (loss) from discontinued operations, net of income taxes presented in the consolidated statements of operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Revenues	$—	$—	$—	$—
Costs and expenses				
General and administrative	(62)	259	1,305	1,162
Decrease in estimated future obligations	(1,765)	(2,144)	(5,460)	(696)
Loss on derivatives, net	—	16	—	34
Income (Loss) From Discontinued Operations Before Income Taxes	1,827	1,869	4,155	(500)
Income tax expense	(706)	(1,077)	(1,930)	(248)
Income (Loss) From Discontinued Operations, Net of Income Taxes	$1,121	$792	$2,225	($748)

Carrizo UK is a disregarded entity for U.S. federal income tax purposes. Accordingly, the income tax expense reflected above includes the Company's U.S. deferred income tax (expense) benefit associated with the income (loss) from discontinued operations before income taxes. The related U.S. deferred tax assets and liabilities have been classified as deferred income taxes of continuing operations in the consolidated balance sheets.

4. Property and Equipment, Net

As of September 30, 2015 and December 31, 2014, total property and equipment, net consisted of the following:

	September 30, 2015	December 31, 2014
	(In thousands)	
Proved properties	$3,785,676	$3,174,268
Accumulated depreciation, depletion and amortization, including impairment	(2,131,543)	(1,087,541)
Proved properties, net	1,654,133	2,086,727
Unproved properties, not being amortized		
Unevaluated leasehold and seismic costs	334,057	401,954
Exploratory wells in progress	17,167	71,402
Capitalized interest	52,289	61,841
Total unproved properties, not being amortized	403,513	535,197
Other property and equipment	23,332	16,017
Accumulated depreciation	(9,959)	(8,688)
Other property and equipment, net	13,373	7,329
Total property and equipment, net	$2,071,019	$2,629,253

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 gas to one barrel of oil, which represents their approximate relative energy content. Average depreciation, depletion and amortization ("DD&A") per Boe of proved properties was $24.19 and $26.75 for the three months ended September 30, 2015 and 2014, respectively, and $23.82 and $26.58 for the nine months ended September 30, 2015 and 2014, respectively.

The Company capitalized internal costs of employee compensation and benefits, including stock-based compensation, directly associated with acquisition, exploration and development activities totaling $3.1 million and $3.4 million for the three months ended September 30, 2015 and 2014, respectively, and $14.0 million and $14.1 million for the nine months ended September 30, 2015 and 2014, 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 the cost of exploratory wells in progress totaling $7.5 million and $8.7 million for the three months ended September 30, 2015 and 2014, respectively, and $26.2 million and $25.0 million for the nine months ended September 30, 2015 and 2014, respectively.

Full Cost Ceiling Test Impairment

Due primarily to declines in the average realized prices for sales of oil and gas on the first calendar day of each month during the trailing 12-month period prior to September 30, 2015, the capitalized costs of oil and gas properties exceeded the cost center ceiling resulting in an after-tax impairment in the carrying value of oil and gas properties of $522.7 million ($812.8 million pre-tax) for the three months and nine months ended September 30, 2015. An impairment recognized in one period may not be reversed in a subsequent period even if higher oil and gas prices in the future increase the cost center ceiling applicable to the subsequent period. There were no impairments of oil and gas properties for the three months ended March 31, 2015 or June 30, 2015 or for the corresponding prior year periods.

Based on the first calendar day of each month oil and gas prices available for the 11 months ended November 1, 2015, the Company expects to record an additional impairment in the carrying value of oil and gas properties in the fourth quarter of 2015. 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 applicable to the third and fourth quarters of 2015.

5. 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.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Income (loss) from continuing operations before income taxes	($811,683)	$130,501	($917,670)	$146,342
Income tax (expense) benefit at the statutory rate	284,089	(45,675)	321,185	(51,220)
State income tax (expense) benefit, net of U.S. Federal income taxes and increase in valuation allowance	6,542	(2,560)	6,321	(2,974)
2015 Texas Franchise Tax rate reduction, net of U.S. Federal income tax expense	—	—	1,671	—
Deferred tax asset valuation allowance	(187,607)	—	(187,607)	—
Other	(109)	731	(1,114)	684
Total income tax (expense) benefit from continuing operations	$102,915	($47,504)	$140,456	($53,510)

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 the 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. The Company 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 September 30, 2015, driven primarily by the full cost ceiling impairment recognized during the third quarter of 2015, which limits the ability to consider other subjective evidence such as the Company's anticipated future growth. In addition, the Company also expects to recognize an additional impairment of its oil and gas properties during the fourth quarter of 2015. The Company also had U.S. federal net operating loss carryforwards of $185.6 million as of December 31, 2014. As a result of the historical and projected future losses, the Company concluded that it is more likely than not that the deferred tax assets will not be realized and recorded a valuation allowance against the net deferred tax asset of as of September 30, 2015 of $187.6 million, reducing the net deferred tax asset 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 that its net deferred tax assets will be realized include, but are not limited to, cumulative historical pre-tax earnings, improvements in 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 the Company concludes that the valuation allowance against its net deferred tax assets is necessary, the Company likely will not have any additional income tax expense or benefit.

6. Long-Term Debt

Long-term debt consisted of the following as of September 30, 2015 and December 31, 2014:

	September 30, 2015	December 31, 2014
	(In thousands)	
Long-term debt		
Deferred purchase payment due 2015	$—	$150,000
Unamortized discount for deferred purchase payment	—	(1,100)
Senior Secured Revolving Credit Facility due 2018	156,490	—
8.625% Senior Notes due 2018	—	600,000
Unamortized discount for 8.625% Senior Notes	—	(3,444)
7.50% Senior Notes due 2020	600,000	600,000
Unamortized premium for 7.50% Senior Notes	1,306	1,465
6.25% Senior Notes due 2023	650,000	—
Other long-term debt due 2028	4,425	4,425
Total long-term debt	$1,412,221	$1,351,346

Senior Secured Revolving Credit Facility

The Company has a senior secured revolving credit facility with a syndicate of banks that, as of September 30, 2015, had a borrowing base of $685.0 million, with $156.5 million of borrowings outstanding with a weighted average interest rate of 1.80%. As of September 30, 2015, the Company also had $0.6 million in letters of credit outstanding which reduced 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.

On May 5, 2015, the Company entered into the sixth amendment to the senior secured revolving credit agreement to, among other things, (i) establish an approved borrowing base of $685.0 million until the next redetermination thereof, (ii) establish a swing line commitment under the revolving credit facility not to exceed $15.0 million and (iii) include seven additional banks to its banking syndicate, bringing the total number of banks to 19 as of the date of such amendment.

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, and which are included as a component of interest expense.

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%

The Company is 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 (as defined in the credit agreement) of not more than 4.00 to 1.00; and (2) a Current Ratio (as defined in the credit agreement) of not less than 1.00 to 1.00. As defined in the credit agreement, Total Debt excludes debt discounts and premiums and is net of cash and cash equivalents, EBITDA is for the last four quarters after giving pro forma effect to certain 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 September 30, 2015, the ratio of Total Debt to EBITDA was 2.97 to 1.00 and the Current Ratio was 2.69 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.

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).

See "Note 13. Subsequent Events - Senior Secured Revolving Credit Facility" for discussion of the seventh amendment to the credit agreement governing the revolving credit facility.

8.625% Senior Notes due 2018

On April 14, 2015, the Company commenced a cash tender offer for any or all of the outstanding $600.0 million aggregate principal amount of its 8.625% Senior Notes. The tender offer expired on April 23, 2015. On April 28, 2015, the Company made an aggregate cash payment of $276.4 million for the $264.2 million aggregate principal amount of 8.625% Senior Notes validly tendered in the tender offer. This represented a tender offer premium totaling $12.2 million, equal to $1,046.13 for each $1,000 principal amount of 8.625% Senior Notes validly tendered and accepted for payment pursuant to the tender offer. In addition, all 8.625% Senior Notes accepted for payment received accrued and unpaid interest of $0.8 million from the last interest payment date up to, but not including, the settlement date.

In connection with the cash tender offer, the Company also sent a notice of redemption to the trustee for its 8.625% Senior Notes to conditionally call for redemption on May 14, 2015 all of the 8.625% Senior Notes then outstanding, conditioned upon and subject to the Company receiving specified net proceeds from one or more securities offerings, which conditions were satisfied. On May 14, 2015, the Company paid an aggregate redemption price of $352.6 million, including a redemption premium of $14.5 million, which represented 104.313% of the principal amount of the then outstanding 8.625% Senior Notes (or $1,043.13 for each $1,000 principal amount of the 8.625% Senior Notes) plus accrued and unpaid interest of $2.3 million from the last interest payment date up to, but not including, the redemption date, to redeem the then outstanding $335.8 million aggregate principal amount of 8.625% Senior Notes.

As a result of the cash tender offer and the redemption of the 8.625% Senior Notes, the Company recorded a loss on extinguishment of debt of $38.1 million during the second quarter of 2015, which includes the premium paid to repurchase the 8.625% Senior Notes of $26.7 million and non-cash charges of $11.4 million attributable to the write-off of unamortized debt issuance costs and the remaining discount associated with the 8.625% Senior Notes.

6.25% Senior Notes due 2023

On April 28, 2015, the Company closed a public offering of $650.0 million aggregate principal amount of 6.25% Senior Notes due 2023. The Company received proceeds of approximately $640.3 million, net of underwriting discounts and commissions. The net proceeds were used to fund the repurchase and redemption of the 8.625% Senior Notes described above as well as to temporarily repay borrowings outstanding under the Company's revolving credit facility. The 6.25% Senior Notes bear interest at 6.25% per annum which is payable semi-annually on each April 15 and October 15 and mature on April 15, 2023. Before April 15, 2018, the Company may, at its option, redeem all or a portion of the 6.25% Senior Notes at 100% of the principal amount plus a make-whole premium. Thereafter, the Company may redeem all or a portion of the 6.25% Senior Notes at redemption prices decreasing from 104.688% to 100% of the principal amount on April 15, 2018, plus accrued and unpaid interest. The 6.25% Senior Notes were guaranteed by the same subsidiaries that also guarantee the 7.50% Senior Notes and the revolving credit facility.

The indenture governing the 6.25% Senior Notes, which is substantially similar to the indenture governing the 7.50% Senior Notes, contains covenants that, among other things, limit the Company's ability and the ability of its restricted subsidiaries to: pay distributions on, purchase or redeem the Company's common stock or other capital stock or redeem the Company's subordinated debt; make investments; incur or guarantee additional indebtedness or issue certain types of equity securities; create certain liens; sell assets; consolidate, merge or transfer all or substantially all of the Company's assets; enter into agreements that restrict distributions or other payments from the Company's restricted subsidiaries to the Company; engage in transactions with affiliates; and create unrestricted subsidiaries. Such indentures governing the Company's senior notes are also subject to customary events of default, including those related to failure to comply with the terms of the notes and the indenture, certain failures to file reports with the SEC, certain cross defaults of other indebtedness and mortgages and certain failures to pay final judgments.

7. 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.

8. Shareholders' Equity

Common Stock Offering

On March 20, 2015, the Company completed a public offering of 5.2 million shares of its common stock at a price of $44.75 per share, which generated proceeds of $231.3 million, net of offering costs. The net proceeds from the common stock offering were used to repay a portion of the borrowings under the Company's revolving credit facility and for general corporate purposes. See "Note 13. Subsequent Events - Common Stock Offering" for discussion of the public offering of the Company's common stock that was completed on October 21, 2015.

Exercise of Warrants

On November 24, 2009, the Company entered into an agreement with an unrelated third party and its affiliate under which the Company issued 118,200 warrants to purchase shares of the Company's common stock. In May 2015, the holders of the warrants exercised all warrants outstanding on a "cashless" basis at an exercise price of $22.09 resulting in the issuance of 71,913 net shares of the Company's common stock.

Stock-Based Compensation

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Stock appreciation rights	($11,557)	($8,935)	($5,666)	$10,637
Restricted stock awards and units	6,013	8,592	17,242	22,517
Performance share awards	598	592	1,363	925
	(4,946)	249	12,939	34,079
Less: amounts capitalized to proved and unproved properties	(647)	(1,179)	(3,736)	(5,870)
Total stock-based compensation expense (benefit), net	($5,593)	($930)	$9,203	$28,209
Income tax benefit (expense)	($1,958)	($326)	$3,221	$9,874

9. Earnings Per Share

Supplemental income (loss) from continuing operations per common share information is provided below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands, except per share amounts)			
Income (Loss) from Continuing Operations	($708,768)	$82,997	($777,214)	$92,832
Basic weighted average common shares outstanding	51,543	45,257	49,742	45,277
Effect of dilutive instruments	—	772	—	832
Diluted weighted average common shares outstanding	51,543	46,029	49,742	46,109
Income (Loss) from Continuing Operations Per Common Share				
Basic	($13.75)	$1.83	($15.62)	$2.05
Diluted	($13.75)	$1.80	($15.62)	$2.01

Basic income (loss) from continuing operations per common share is based on the weighted average number of shares of common stock outstanding during the period. Diluted income (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. 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.

For the three and nine months ended September 30, 2015, the calculation of diluted weighted average common shares outstanding excluded the anti-dilutive effect of 0.4 million shares of restricted stock awards and units and performance share awards and 0.7 million shares of restricted stock awards and units, performance share awards, options and warrants due to the loss from continuing operations, respectively. For the three and nine months ended September 30, 2014, the number of shares of restricted stock awards and units, performance share awards, options and warrants excluded were insignificant.

10. 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 September 30, 2015, the Company’s commodity derivative instruments consisted of fixed price swaps, costless collars 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. In exchange for selling these 2017-2020 options, the Company received upfront proceeds which it used to obtain a higher fixed price on its 2016 fixed price swaps. 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.

The following sets forth a summary of the Company’s open crude oil derivative positions at average NYMEX prices as of September 30, 2015:

Period	Type of Contract	Volumes (in Bbls/d)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)
October - December 2015	Costless Collars	16,200	$50.00	$67.34
2016	Costless Collars	5,490	$50.96	$74.73
2016	Fixed Price Swaps	3,000	$60.00	
2017	Sold Call Options	750		$60.00
2018	Sold Call Options	938		$60.00
2019	Sold Call Options	1,125		$62.50
2020	Sold Call Options	1,500		$65.00

On February 11, 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 $40.0 million and $79.9 million were received due to contract settlements during the three months ended September 30, 2015 and nine months ended September 30, 2015, respectively, and is included in the gain on derivatives, net in the consolidated statements of operations. As of September 30, 2015, the fair value of the remaining locked in cash flows is $86.4 million, of which $75.8 million is classified as a current derivative asset and $10.6 million is classified as a noncurrent derivative asset 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. Included in the $42.6 million gain on derivatives, net for the nine months ended September 30, 2015, is an $8.4 million gain representing the increase in fair value of the then-existing crude oil derivative positions from December 31, 2014 to February 11, 2015. The offsetting derivative transactions are not included in the table above.

Additionally, subsequent to entering into the offsetting derivative transactions described above, the Company entered into costless collars for the periods from March 2015 through December 2016 that will continue to provide the Company with downside protection at crude oil prices below the weighted average floor prices yet allow the Company to benefit from an increase in crude oil prices up to the weighted average ceiling prices. During the third quarter of 2015, the Company sold call options for the years 2017 through 2020 and used the upfront proceeds received from the sale of those call options to obtain a higher fixed price on the 2016 fixed price swaps, as discussed above. See “Note 13. Subsequent Events - Hedging Activity” for discussion of derivative instruments entered into subsequent to September 30, 2015.

The following sets forth a summary of the Company’s natural gas derivative positions at average NYMEX prices as of September 30, 2015:

Period	Type of Contract	Volumes (in MMBtu/d)	Weighted Average Fixed Price ($/MMBtu)

October - December 2015	Fixed Price Swaps	30,000	$4.29

For the three months ended September 30, 2015 and 2014, the Company recorded in the consolidated statements of operations a gain on derivatives, net of $28.8 million and $71.8 million, respectively. For the nine months ended September 30, 2015 and 2014, the Company recorded in the consolidated statements of operations a gain on derivatives, net of $42.6 million and $11.2 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. The Company nets its derivative instrument fair value amounts 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 September 30, 2015 and December 31, 2014 totaled $115.3 million and $214.8 million, respectively, and is summarized by counterparty in the table below:

Counterparty	September 30, 2015		December 31, 2014	
Wells Fargo	51	%	37	%
Societe Generale	31	%	26	%
Regions	11	%	8	%
Union Bank	6	%	4	%
Royal Bank of Canada	1	%	1	%
Credit Suisse	—	%	24	%
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 resulting from adverse changes in the fair value of its derivative instruments 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.

11. 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 September 30, 2015 and December 31, 2014. All items included in the tables below are Level 2 inputs within the fair value hierarchy:

	September 30, 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	$138,016	($29,134)	$108,882
Derivative assets-noncurrent	20,582	(14,125)	6,457
Derivative liabilities			
Other current liabilities	(29,201)	29,134	(67)
Other liabilities	(14,125)	14,125	—
Total	$115,272	$—	$115,272

	December 31, 2014		
	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	$183,625	($12,524)	$171,101
Derivative assets-noncurrent	44,725	(1,041)	43,684
Derivative liabilities			
Other current liabilities	(12,707)	12,524	(183)
Other liabilities	(1,058)	1,041	(17)
Total	$214,585	$—	$214,585

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, as well as the Company's crude oil derivative instruments that were entered into subsequent to the offsetting derivative transactions, 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. 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 nine months ended September 30, 2015 and 2014.

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 with the exception of the deferred purchase payment, which is classified as Level 2 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 long-term debt with the fair values of the Company's senior notes and other long-term debt based on quoted market prices and the fair value of the deferred purchase payment based on indirect observable market rates.

	September 30, 2015		December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Deferred purchase payment due 2015	$—	$—	$148,900	$148,558
8.625% Senior Notes due 2018	—	—	596,555	597,000
7.50% Senior Notes due 2020	601,306	559,500	601,466	573,000
6.25% Senior Notes due 2023	650,000	568,750	—	—
Other long-term debt due 2028	4,425	4,115	4,425	4,071

12. 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.

Investments in subsidiaries are accounted for by the respective parent company using the equity method for purposes of this presentation. Results of operations of subsidiaries are therefore reflected in the parent company's investment accounts and earnings. The principal elimination entries set forth below eliminate investments in subsidiaries and intercompany balances and transactions. Typically in a condensed consolidating financial statement, the net income and equity of the parent company equals the net income and equity of the consolidated entity. The Company's oil and gas properties are accounted for using the full cost method of accounting whereby impairments and DD&A are calculated and recorded on a country by country basis. However, when calculated separately on a legal entity basis, the combined totals of parent company and subsidiary impairments and DD&A can be more or less than the consolidated total as a result of differences in the properties each entity owns including amounts of costs incurred, production rates, reserve mix, future development costs, etc. Accordingly, elimination entries are required to eliminate any differences between consolidated and parent company and subsidiary company combined impairments and DD&A.

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

	September 30, 2015				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Total current assets	$2,435,168	$54,592	$—	($2,318,484)	$171,276
Total property and equipment, net	44,924	2,025,508	3,059	(2,472)	2,071,019
Investment in subsidiaries	(424,195)	—	—	424,195	—
Other assets	100,060	154	—	(24,222)	75,992
Total Assets	$2,155,957	$2,080,254	$3,059	($1,920,983)	$2,318,287
Liabilities and Shareholders' Equity					
Current liabilities	$143,420	$2,477,107	$3,059	($2,321,503)	$302,083
Long-term liabilities	1,422,239	27,342	—	(11,757)	1,437,824
Total shareholders' equity	590,298	(424,195)	—	412,277	578,380
Total Liabilities and Shareholders' Equity	$2,155,957	$2,080,254	$3,059	($1,920,983)	$2,318,287

	December 31, 2014				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Total current assets	$2,380,445	$245,051	$111	($2,346,986)	$278,621
Total property and equipment, net	613	2,562,029	39,939	26,672	2,629,253
Investment in subsidiaries	233,173	—	—	(233,173)	—
Other assets	140,774	—	—	(67,172)	73,602
Total Assets	$2,755,005	$2,807,080	$40,050	($2,620,659)	$2,981,476
Liabilities and Shareholders' Equity					
Current liabilities	$296,686	$2,434,649	$39,955	($2,346,986)	$424,304
Long-term liabilities	1,364,793	139,353	—	(50,415)	1,453,731
Total shareholders' equity	1,093,526	233,078	95	(223,258)	1,103,441
Total Liabilities and Shareholders' Equity	$2,755,005	$2,807,080	$40,050	($2,620,659)	$2,981,476

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

	Three Months Ended September 30, 2015				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$235	$106,002	$—	$—	$106,237
Total costs and expenses	(6,718)	890,350	—	34,288	917,920
Income (loss) from continuing operations before income taxes	6,953	(784,348)	—	(34,288)	(811,683)
Income tax (expense) benefit	(25,496)	119,847	—	8,564	102,915
Equity in loss of subsidiaries	(664,501)	—	—	664,501	—
Loss from continuing operations	(683,044)	(664,501)	—	638,777	(708,768)
Income from discontinued operations, net of income taxes	1,121	—	—	—	1,121
Net loss	($681,923)	($664,501)	$—	$638,777	($707,647)

	Three Months Ended September 30, 2014				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$924	$195,301	$—	$—	$196,225
Total costs and expenses	(42,829)	116,622	—	(8,069)	65,724
Income from continuing operations before income taxes	43,753	78,679	—	8,069	130,501
Income tax expense	(15,312)	(27,538)	—	(4,654)	(47,504)
Equity in income of subsidiaries	51,141	—	—	(51,141)	—
Income from continuing operations	79,582	51,141	—	(47,726)	82,997
Income from discontinued operations, net of income taxes	792	—	—	—	792
Net income	$80,374	$51,141	$—	($47,726)	$83,789

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

	Nine Months Ended September 30, 2015				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$1,485	$328,296	$—	$—	$329,781
Total costs and expenses	116,793	1,101,671	—	28,987	1,247,451
Loss from continuing operations before income taxes	(115,308)	(773,375)	—	(28,987)	(917,670)
Income tax benefit	17,296	116,006	—	7,154	140,456
Equity in loss of subsidiaries	(657,369)	—	—	657,369	—
Loss from continuing operations	(755,381)	(657,369)	—	635,536	(777,214)
Income from discontinued operations, net of income taxes	2,225	—	—	—	2,225
Net loss	($753,156)	($657,369)	$—	$635,536	($774,989)

	Nine Months Ended September 30, 2014				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$3,696	$543,216	$—	$—	$546,912
Total costs and expenses	90,811	315,619	—	(5,860)	400,570
Income (loss) from continuing operations before income taxes	(87,115)	227,597	—	5,860	146,342
Income tax (expense) benefit	30,491	(79,659)	—	(4,342)	(53,510)
Equity in income of subsidiaries	147,938	—	—	(147,938)	—
Income from continuing operations	91,314	147,938	—	(146,420)	92,832
Loss from discontinued operations, net of income taxes	(748)	—	—	—	(748)
Net income	$90,566	$147,938	$—	($146,420)	$92,084

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

	Nine Months Ended September 30, 2015				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities from continuing operations	($8,817)	$293,036	$—	$—	$284,219
Net cash used in investing activities from continuing operations	(396,036)	(529,046)	—	386,010	(539,072)
Net cash provided by financing activities from continuing operations	399,391	236,010	—	(386,010)	249,391
Net cash used in discontinued operations	(3,372)	—	—	—	(3,372)
Net decrease in cash and cash equivalents	(8,834)	—	—	—	(8,834)
Cash and cash equivalents, beginning of period	10,838	—	—	—	10,838
Cash and cash equivalents, end of period	$2,004	$—	$—	$—	$2,004

	Nine Months Ended September 30, 2014				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities from continuing operations	($132,889)	$521,576	$—	$—	$388,687
Net cash used in investing activities from continuing operations	(132,605)	(632,160)	(24,717)	135,301	(654,181)
Net cash provided by financing activities from continuing operations	123,151	110,584	24,717	(135,301)	123,151
Net cash used in discontinued operations	(7,935)	—	—	—	(7,935)
Net decrease in cash and cash equivalents	(150,278)	—	—	—	(150,278)
Cash and cash equivalents, beginning of period	157,439	—	—	—	157,439
Cash and cash equivalents, end of period	$7,161	$—	$—	$—	$7,161

13. Subsequent Events

Common Stock Offering

On October 21, 2015, the Company completed a public offering of 6.3 million shares of its common stock at a price of $37.80 per share, which generated proceeds of $239.1 million, net of underwriting discounts. The Company used a portion of the net proceeds from the common stock offering to repay borrowings under the Company’s revolving credit facility, with the remainder to be used for general corporate purposes, including future potential acquisitions with a primary focus in the Delaware Basin.

Senior Secured Revolving Credit Facility

On October 30, 2015, the Company entered into the seventh amendment to the senior secured revolving credit agreement to, among other things, (i) reaffirm the borrowing base at its current level of $685.0 million until the next redetermination thereof and (ii) amend the financial covenant requiring the maintenance of a ratio of Total Debt to EBITDA of not more than 4.00 to 1.00, such that the permissible ratio is increased to 4.75 to 1.00 through December 31, 2016, reducing to 4.375 to 1.00 through December 31, 2017, and returning to 4.00 to 1.00 thereafter.

Hedging Activity

Subsequent to September 30, 2015, the Company entered into the following derivative instruments:

Period	Type of Contract	Volumes (in Bbls/d)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)
2016	Fixed Price Swaps	6,315	$60.04	
2017	Sold Call Options	1,750		$60.00
2018	Sold Call Options	2,450		$60.00
2019	Sold Call Options	2,750		$62.50
2020	Sold Call Options	3,075		$65.00

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 Company's financial position and results of operations 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, 2014.

General Overview

Production and Commodity Prices. Total production for the three months ended September 30, 2015 was 35,948 Boe/d, an increase of 7% from the 33,587 Boe/d for the three months ended September 30, 2014 primarily driven by increased crude oil production in the Eagle Ford and Utica, partially offset by decreased natural gas production due to voluntary curtailments in the Marcellus. Average realized crude oil, natural gas liquids and natural gas prices for the third quarter of 2015 were $43.91 per Bbl, $9.62 per Bbl and $1.61 per Mcf, respectively, which represent decreases of 53%, 66% and 38% from the third quarter of 2014, respectively. As a result, despite the increase in crude oil production, our third quarter of 2015 revenues of $106.2 million were 46% lower than our third quarter of 2014 revenues of $196.2 million.

Drilling and Completion Activity. See the table below for details of our operated drilling and completion activity by region:

	Three Months Ended September 30, 2015				As of September 30, 2015				
	Drilled		Wells Brought on Production		Waiting on Completion		Producing		Rig count
Region	Gross	Net	Gross	Net	Gross	Net	Gross	Net	
Eagle Ford	20	18.5	21	17.5	25	23.2	243	214.8	2
Niobrara	—	—	—	—	17	9.8	115	49.3	—
Marcellus	—	—	—	—	11	4.3	82	26.3	—
Utica	—	—	—	—	—	—	4	3.1	—
Delaware Basin	1	0.8	—	—	1	0.8	—	—	1
Total	21	19.3	21	17.5	54	38.1	444	293.5	3

Financing Activities. In October 2015, we sold 6.3 million shares of our common stock in an underwritten public offering at a price of $37.80 per share. We used a portion of the proceeds of approximately $239.1 million, net of underwriting discounts, to repay borrowings under our revolving credit facility, with the remainder to be used for general corporate purposes, including future potential acquisitions with a primary focus in the Delaware Basin.

In October 2015, we entered into the seventh amendment to the credit agreement governing the revolving credit facility. The revolving credit facility was amended to, among other things, (i) reaffirm the borrowing base at its current level of $685.0 million until the next redetermination and (ii) amend the financial covenant requiring the maintenance of a ratio of Total Debt to EBITDA (as defined in the credit agreement) of not more than 4.00 to 1.00, such that the permissible ratio is increased to 4.75 to 1.00 through December 31, 2016, reducing to 4.375 to 1.00 through December 31, 2017, and returning to 4.00 to 1.00 thereafter.

Results of Operations

Three Months Ended September 30, 2015, Compared to the Three Months Ended September 30, 2014

The following table summarizes total production volumes, daily production volumes, average realized prices and revenues for the three months ended September 30, 2015 and 2014:

	Three Months Ended September 30,		2015 Period Compared to 2014 Period	
	2015	2014	Increase (Decrease)	% Increase (Decrease)
Total production volumes -				
Crude oil (MBbls)	2,169	1,840	329	18 %
NGLs (MBbls)	346	274	72	26 %
Natural gas (MMcf)	4,757	5,854	(1,097)	(19 %)
Total Natural gas and NGLs (MMcfe)	6,831	7,498	(667)	(9 %)
Total barrels of oil equivalent (MBoe)	3,307	3,090	217	7 %
Daily production volumes by product -				
Crude oil (Bbls/d)	23,573	20,000	3,573	18 %
NGLs (Bbls/d)	3,757	2,978	779	26 %
Natural gas (Mcf/d)	51,710	63,630	(11,920)	(19 %)
Total Natural gas and NGLs (Mcfe/d)	74,252	81,500	(7,248)	(9 %)
Total barrels of oil equivalent (Boe/d)	35,948	33,587	2,361	7 %
Daily production volumes by region (Boe/d) -				
Eagle Ford	26,913	23,153	3,760	16 %
Niobrara	2,735	2,790	(55)	(2 %)
Marcellus	4,443	7,348	(2,905)	(40 %)
Utica	1,707	20	1,687	8,435 %
Other	150	276	(126)	(46 %)
Total barrels of oil equivalent (Boe/d)	35,948	33,587	2,361	7 %
Average realized prices -				
Crude oil ($ per Bbl)	$43.91	$94.17	($50.26)	(53 %)
NGLs ($ per Bbl)	9.62	28.46	(18.84)	(66 %)
Natural gas ($ per Mcf)	1.61	2.59	(0.98)	(38 %)
Total Natural gas and NGLs ($ per Mcfe)	$1.61	$3.06	($1.45)	(47 %)
Total average realized price ($ per Boe)	$32.12	$63.50	($31.38)	(49 %)
Revenues (In thousands) -				
Crude oil	$95,237	$173,277	($78,040)	(45 %)
NGLs	3,330	7,798	(4,468)	(57 %)
Natural gas	7,670	15,150	(7,480)	(49 %)
Total revenues	$106,237	$196,225	($89,988)	(46 %)

Revenues for the three months ended September 30, 2015 decreased 46% to $106.2 million from $196.2 million for the same period in 2014 primarily due to the decrease in crude oil and natural gas prices, partially offset by the increase in crude oil production. Production volumes for the three months ended September 30, 2015 and 2014 were 35,948 Boe/d and 33,587 Boe/d, respectively. The increase in production from the third quarter of 2014 to the third quarter of 2015 was primarily due to increased production from new wells in the Eagle Ford and Utica, partially offset by normal production declines and voluntary curtailments of natural gas production in the Marcellus due to unfavorable natural gas prices.

Lease operating expenses for the three months ended September 30, 2015 increased to $22.2 million ($6.72 per Boe) from $21.0 million ($6.80 per Boe) for the same period in 2014. The increase in lease operating expenses is primarily due to increased production from new wells in the Eagle Ford, partially offset by reduced costs due 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 primarily due to the lower

salt water disposal costs described above partially offset by an increased proportion of total production from crude oil properties, which have a higher operating cost per Boe than natural gas properties.
Production taxes decreased to $4.3 million (or 4.0% of revenues) for the three months ended September 30, 2015 from $8.4 million (or 4.3% of revenues) for the same period in 2014 as a result of the decrease in crude oil and natural gas revenues, partially offset by increased crude oil production. The decrease in production taxes as a percentage of revenues is primarily due to a benefit in the third quarter of 2015 of lower actual production taxes than previously estimated in Niobrara, partially offset by lower production in the Marcellus, which is not subject to production taxes.
Ad valorem taxes increased to $2.3 million for the three months ended September 30, 2015 from $2.2 million for the same period in 2014. The increase in ad valorem taxes is due to new wells drilled in Eagle Ford in 2014, partially offset by a decrease in our annual estimate of ad valorem taxes.
DD&A expense for the third quarter of 2015 decreased $2.3 million to $81.3 million ($24.57 per Boe) from the DD&A expense for the third quarter of 2014 of $83.6 million ($27.05 per Boe). The decrease in DD&A expense is attributable to the decrease in the DD&A rate per Boe, partially offset by increased production. The decrease in the DD&A rate per Boe from the third quarter of 2014 to the third quarter of 2015 is primarily due to a reduction in future development costs. The components of our DD&A expense were as follows:

	Three Months Ended September 30,	
	2015	2014
	(In thousands)	
DD&A of proved oil and gas properties	$80,016	$82,645
Depreciation of other property and equipment	521	433
Amortization of other assets	432	293
Accretion of asset retirement obligations	287	201
Total DD&A	$81,256	$83,572

We recognized an after-tax impairment of $522.7 million ($812.8 million pre-tax) for the three months ended September 30, 2015 due primarily to declines in the average realized prices for sales of oil and gas on the first calendar day of each month during the trailing 12-month period prior to September 30, 2015. There was no impairment of oil and gas properties for the three months ended September 30, 2014.
General and administrative expense decreased to $4.2 million for the three months ended September 30, 2015 from $9.5 million for the corresponding period in 2014. The decrease was primarily due to a decrease in stock-based compensation expense associated with stock appreciation rights as a result of a decline in the fair value of stock appreciation rights for the three months ended September 30, 2015 as compared to the same period of 2014.
The gain on derivatives, net for the three months ended September 30, 2015 amounted to $28.8 million primarily due to new crude oil hedge positions executed during 2015 and the downward shift in the futures curve of forecasted commodity prices for crude oil from July 1, 2015 to September 30, 2015. The gain on derivatives, net for the three months ended September 30, 2014 amounted to $71.8 million primarily due to the downward shift in the futures curve of forecasted commodity prices for crude oil and natural gas from July 1, 2014 (or the subsequent date on which new contracts were entered into) to September 30, 2014.

Interest expense, net for the three months ended September 30, 2015 was $16.2 million as compared to $12.2 million for the same period in 2014. The increase was primarily due to the interest expense on the $300.0 million aggregate principal amount of our 7.50% Senior Notes that were issued in October 2014, the $650.0 million aggregate principal amount of our 6.25% Senior Notes that were issued in April 2015 and a decrease in the associated capitalized interest as a result of a lower effective interest rate on debt outstanding during the three months ended September 30, 2015 as compared to the same period in 2014, partially offset by a reduction in interest expense associated with the $600.0 million aggregate principal amount of our 8.625% Senior Notes that were redeemed in April 2015. The components of our interest expense, net were as follows:

	Three Months Ended September 30,	
	2015	2014
	(In thousands)	
Interest expense on Senior Notes	$21,455	$18,611
Interest expense on revolving credit facility	1,131	1,140
Amortization of debt issuance costs, premiums, and discounts	1,000	1,158
Other interest expense	140	13
Capitalized interest	(7,518)	(8,721)
Interest expense, net	$16,208	$12,201

The effective income tax rate for the third quarter of 2015 and 2014 was 12.7% and 36.4%, respectively. The variance from the U.S. Federal statutory rate of 35% for the three months ended September 30, 2015 was primarily due to a valuation allowance of $187.6 million that was recorded against our net deferred tax asset during the third quarter of 2015. The variance from the U.S. Federal statutory rate of 35% for the three months ended September 30, 2014 was due to the impact of state income taxes.

Results of Operations

Nine Months Ended September 30, 2015, Compared to the Nine Months Ended September 30, 2014

The following table summarizes total production volumes, daily production volumes, average realized prices and revenues for the nine months ended September 30, 2015 and 2014:

	Nine Months Ended September 30,		2015 Period Compared to 2014 Period	
	2015	2014	Increase (Decrease)	% Increase (Decrease)
Total production volumes -				
Crude oil (MBbls)	6,120	4,870	1,250	26 %
NGLs (MBbls)	981	648	333	51 %
Natural gas (MMcf)	15,637	17,951	(2,314)	(13 %)
Total Natural gas and NGLs (MMcfe)	21,524	21,839	(315)	(1 %)
Total barrels of oil equivalent (MBoe)	9,708	8,510	1,198	14 %
Daily production volumes by product -				
Crude oil (Bbls/d)	22,418	17,839	4,579	26 %
NGLs (Bbls/d)	3,594	2,374	1,220	51 %
Natural gas (Mcf/d)	57,280	65,755	(8,475)	(13 %)
Total Natural gas and NGLs (Mcfe/d)	78,844	79,996	(1,152)	(1 %)
Total barrels of oil equivalent (Boe/d)	35,559	31,172	4,387	14 %
Daily production volumes by region (Boe/d) -				
Eagle Ford	25,473	19,753	5,720	29 %
Niobrara	3,063	2,497	566	23 %
Marcellus	5,484	8,222	(2,738)	(33 %)
Utica	1,308	173	1,135	656 %
Other	231	527	(296)	(56 %)
Total barrels of oil equivalent (Boe/d)	35,559	31,172	4,387	14 %
Average realized prices -				
Crude oil ($ per Bbl)	$47.31	$96.43	($49.12)	(51 %)
NGLs ($ per Bbl)	11.83	30.35	(18.52)	(61 %)
Natural gas ($ per Mcf)	1.83	3.21	(1.38)	(43 %)
Total Natural gas and NGLs ($ per Mcfe)	$1.87	$3.54	($1.67)	(47 %)
Total average realized price ($ per Boe)	$33.97	$64.27	($30.30)	(47 %)
Revenues (In thousands) -				
Crude oil	$289,552	$469,601	($180,049)	(38 %)
NGLs	11,602	19,669	(8,067)	(41 %)
Natural gas	28,627	57,642	(29,015)	(50 %)
Total revenues	$329,781	$546,912	($217,131)	(40 %)

Revenues for the nine months ended September 30, 2015 decreased 40% to $329.8 million from $546.9 million for the same period in 2014 primarily due to the decrease in crude oil and natural gas prices, partially offset by the increase in crude oil production. Production volumes for the nine months ended September 30, 2015 and 2014 were 35,559 Boe/d and 31,172 Boe/d, respectively. The increase in production from the nine months ended September 30, 2014 to the nine months ended September 30, 2015 was primarily due to increased production from new wells in the Eagle Ford, partially offset by normal production declines and voluntary curtailments of natural gas production in the Marcellus due to unfavorable natural gas prices.

Lease operating expenses for the nine months ended September 30, 2015 increased to $67.3 million ($6.93 per Boe) from $51.0 million ($5.99 per Boe) for the same period in 2014. The increase in lease operating expenses is primarily due to increased production from new wells in the Eagle Ford. The increase in lease operating expense per Boe is primarily due to an increased proportion of total production from crude oil properties, which have a higher operating cost per Boe than natural gas properties.

Production taxes decreased to $13.3 million (or 4.0% of revenues) for the nine months ended September 30, 2015 from $22.7 million (or 4.1% of revenues) for the same period in 2014 as a result of the decrease in crude oil and natural gas revenues, partially offset by increased crude oil production. The decrease in production taxes as a percentage of revenues is primarily due to a benefit in the third quarter of 2015 of lower actual production taxes than previously estimated in Niobrara, partially offset by lower production in the Marcellus, which is not subject to production taxes.

Ad valorem taxes increased to $7.0 million for the nine months ended September 30, 2015 from $5.6 million for the same period in 2014. The increase in ad valorem taxes for the nine months ended September 30, 2015 is primarily due to new wells drilled in Eagle Ford in 2014, partially offset by a decrease in our annual estimate of ad valorem taxes.

DD&A expense for the nine months ended September 30, 2015 increased $5.5 million to $234.5 million ($24.15 per Boe) from $228.9 million ($26.90 per Boe) for the same period in 2014. The increase in DD&A expense is attributable to increased production, partially offset by the decrease in the DD&A rate per Boe. The decrease in the DD&A rate per Boe is primarily due to a reduction in future development costs. The components of our DD&A expense were as follows:

	Nine Months Ended September 30,	
	2015	2014
	(In thousands)	
DD&A of proved oil and gas properties	$231,250	$226,217
Depreciation of other property and equipment	1,271	1,309
Amortization of other assets	1,123	894
Accretion of asset retirement obligations	814	492
Total DD&A	$234,458	$228,912

We recognized an after-tax impairment of $522.7 million ($812.8 million pre-tax) for the nine months ended September 30, 2015 due primarily to declines in the average realized prices for sales of oil and gas on the first calendar day of each month during the trailing 12-month period prior to September 30, 2015. There were no impairments of oil and gas properties for the nine months ended September 30, 2014.

General and administrative expense decreased to $54.9 million for the nine months ended September 30, 2015 from $65.5 million for the same period in 2014. The decrease was primarily due to a decrease in stock-based compensation expense resulting from a decrease in the fair value of stock appreciation rights for the nine months ended September 30, 2015 compared to the same period in 2014 and a decrease in the number of stock appreciation rights and restricted stock outstanding during the nine months ended September 30, 2015, partially offset by accruals for estimated 2015 bonuses.

The gain on derivatives, net for the nine months ended September 30, 2015 amounted to $42.6 million primarily due to new crude oil hedge positions executed during 2015, the downward shift in the futures curve of forecasted commodity prices for crude oil during the first quarter of 2015 prior to our lock-in of our then existing crude oil derivative positions as well as during the third quarter of 2015, and the downward shift in the futures curve of forecasted commodity prices for natural gas from January 1, 2015 to September 30, 2015. The gain on derivatives, net for the nine months ended September 30, 2014 amounted to $11.2 million primarily due to new hedge additions during 2014 and the significant downward shift in the futures curve of forecasted commodity prices for crude oil and natural gas from July 1, 2014 (or the subsequent date new contracts were entered into) to September 30, 2014, partially offset by the upward shift in the commodity prices for crude oil from January 1, 2014 to June 30, 2014.

Interest expense, net for the nine months ended September 30, 2015 was $51.4 million as compared to $36.6 million for the same period in 2014. The increase was primarily due to the interest expense on the $300.0 million aggregate principal amount of our 7.50% Senior Notes that were issued in October 2014, the accretion of the discount on the deferred purchase payment due to Eagle Ford Minerals, LLC in February 2015 and the interest expense on the $650.0 million aggregate principal amount of our 6.25% Senior Notes that were issued in April 2015, partially offset by a reduction in interest expense associated with the $600.0 million aggregate principal amount of our 8.625% Senior Notes that were redeemed in April 2015 and the associated increase in capitalized interest. The components of our interest expense, net were as follows:

	Nine Months Ended September 30,	
	2015	2014
	(In thousands)	
Interest expense on Senior Notes	$69,428	$55,833
Interest expense on revolving credit facility	3,296	2,299
Amortization of debt issuance costs, premiums, and discounts	3,622	3,405
Other interest expense	1,247	24
Capitalized interest	(26,190)	(25,004)
Interest expense, net	$51,403	$36,557

The effective income tax rate for the nine months ended September 30, 2015 and 2014 was 15.3% and 36.6%, respectively. The variance from the U.S. Federal statutory rate of 35% for the nine months ended September 30, 2015 was primarily due to a valuation allowance of $187.6 million that was recorded against our net deferred tax asset during the third quarter of 2015. The variance from the U.S. Federal statutory rate of 35% for the nine months ended September 30, 2014 was due to the impact of state income taxes.

Liquidity and Capital Resources

2015 Capital Expenditure Plan. The range of our previously provided 2015 drilling and completion capital expenditure plan of $470.0 million to $490.0 million has been narrowed to $480.0 million to $490.0 million as a result of additional operated completions as well as higher non-operated activity in Niobrara and additional Eagle Ford activity. Our leasehold and seismic capital expenditure plan is increased to $55.0 million from $45.0 million as a result of additional acquisitions in the Delaware Basin that may occur and excludes several larger potential Delaware Basin acquisitions that we are pursuing. We currently expect to allocate the majority of the remaining capital to acreage acquisitions in the Eagle Ford and Delaware Basin. We currently intend to finance the remainder of our 2015 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 September 30, 2015:

	Three Months Ended			Nine Months Ended
	March 31, 2015	June 30, 2015	September 30, 2015	September 30, 2015
	(In thousands)			
Drilling and completion				
Eagle Ford	$103,338	$105,833	$105,992	$315,163
Niobrara	20,486	12,976	5,567	39,029
Utica	22,971	(2,591)	256	20,636
Marcellus	3,280	557	(2,795)	1,042
Other	1,487	692	13,067	15,246
Total drilling and completion	151,562	117,467	122,087	391,116
Leasehold and seismic (1)	12,440	18,770	7,754	38,964
Total	$164,002	$136,237	$129,841	$430,080

(1) Leasehold and seismic for the three months ended June 30, 2015 is presented net of approximately $6.5 million of proceeds related to acreage positions offered to and accepted by joint venture partners.

Our capital expenditure plan and the capital expenditures included above exclude capitalized general and administrative costs, interest and 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 nine months ended September 30, 2015, capital expenditures and acquisitions of oil and gas properties, net of proceeds from sales of oil and gas properties, exceeded our net cash provided by operations for continuing operations. For the nine months ended September 30, 2015, we funded our capital expenditures with cash provided by operations, borrowings under our revolving credit facility and a portion of the net proceeds from our March 2015 equity offering and, to a lesser degree, our April 2015 debt offering, which were also used to repay 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 commodity prices. As such, we hedge a portion of our forecasted production to mitigate the risk of a decline in crude oil and natural gas prices.
- Borrowings under our revolving credit facility. As of October 30, 2015, we had no borrowings outstanding and $0.6 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 additional asset sales of non-core properties.
- Securities offerings. As situations or conditions arise, we may choose to issue debt, equity or other instruments 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. In October 2015, we sold 6.3 million shares of our common stock in an underwritten public offering at a price of $37.80 per share. We used a portion of the proceeds of approximately $239.1 million, net of underwriting discounts, to repay borrowings under our revolving credit facility, with the remainder to be used for general corporate purposes, including future potential acquisitions with a primary focus in the Delaware Basin.
- 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 $284.2 million and $388.7 million for the nine months ended September 30, 2015 and 2014, respectively. The change was primarily due to a decrease in oil and gas revenues and an increase in operating expenses and working capital requirements, partially offset by an increase in the net cash from derivative settlements.

Net cash used in investing activities from continuing operations were $539.1 million and $654.2 million for the nine months ended September 30, 2015 and 2014, respectively and relate primarily to reduced oil and gas capital expenditures associated with our 2015 capital expenditure plan, which was reduced by approximately 39% as compared to our 2014 capital expenditures.

Net cash provided by financing activities from continuing operations were $249.4 million and $123.2 million for the nine months ended September 30, 2015 and 2014, respectively. The increase was due to net proceeds related to the issuance of common stock in March 2015, issuance of the 6.25% Senior Notes in April 2015, and increased borrowings under the revolving credit facility, partially offset by the tender and redemption of the 8.625% Senior Notes and 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. We currently believe that cash flows from operations and borrowings under our revolving credit facility will be sufficient to fund our immediate cash flow requirements. Cash flows from operations are primarily driven by production and commodity prices. As a result of the significant decline in crude oil prices, our revenues, and thus our cash flows from operations have also declined. 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. On February 11, 2015, we entered into derivative transactions offsetting our then existing crude oil derivative positions covering the periods from March 2015 through December 2016, which locked in $166.4 million of cash flows, of which $40.0 million and $79.9 million were received due to contract settlements during the three and nine months ended September 30, 2015, respectively. Subsequent to the offsetting derivative transactions, we entered into costless collars for periods from March 2015 through December 2016, fixed price swaps for periods from January 2016 through December 2016, and short calls for periods from January 2017 through December 2020. See “—Volatility of Crude Oil and Natural Gas Prices” for details of our derivative positions as of September 30, 2015 and “Note 13. Subsequent Events - Hedging Activity” for discussion of derivative instruments entered into subsequent to September 30, 2015.

As of October 30, 2015, we had no borrowings outstanding under our revolving credit facility and had issued $0.6 million in letters of credit outstanding, which reduce the amounts available under our revolving credit facility. The borrowing base under our revolving credit facility is affected by our lenders' assumptions with respect to future crude oil and natural gas prices. Our borrowing base may decrease if our lenders reduce their expectations with respect to future crude oil and natural gas prices from those assumptions used to determine our existing borrowing base. The Fall 2015 borrowing base redetermination resulted in a borrowing base of $685.0 million, which was unchanged from the prior borrowing base. Looking forward to the Spring 2016 borrowing base redetermination, based on currently available bank pricing assumptions and current pricing differentials, drilling and completion plans, and reserve and cost assumptions, we expect the Spring 2016 redetermination to result in a borrowing base that is either unchanged or slightly higher as compared to our current $685.0 million borrowing base. These assumptions and other matters may change materially. Additionally, the borrowing base amount is subject to considerable discretion by the banks. 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.

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 our 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 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 September 30, 2015 (in thousands):

	October - December 2015	2016	2017	2018	2019	2020 and Thereafter	Total
Long-term debt (1)	$—	$—	$—	$156,490	$—	$1,254,425	$1,410,915
Cash interest on long-term debt (2)	21,577	90,617	90,617	88,238	85,819	188,817	565,685
Capital leases	433	1,733	1,733	1,700	1,677	978	8,254
Operating leases	1,014	4,055	4,185	4,248	4,357	10,753	28,612
Drilling rig contracts (3)	9,710	24,261	20,513	3,957	—	—	58,441
Pipeline volume commitments	2,469	5,580	2,465	2,465	2,390	5,475	20,844
Asset retirement obligations and other (4)	1,190	3,180	1,346	4	24	14,456	20,200
Total Contractual Obligations	$36,393	$129,426	$120,859	$257,102	$94,267	$1,474,904	$2,112,951

(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 long-term debt includes cash payments for interest on the 7.50% Senior Notes due 2020, the 6.25% Senior Notes due 2023, other long-term debt due 2028 and the borrowings outstanding under our revolving credit facility which matures in 2018. 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 September 30, 2015 of 1.80%.

(3) 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.

(4) Asset retirement obligations and other are based on estimates and assumptions that affect the reported amounts as of September 30, 2015. 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 September 30, 2015, had a borrowing base of $685.0 million, with $156.5 million of borrowings outstanding with a weighted average interest rate of 1.80% and $0.6 million in letters of credit outstanding. The credit agreement governing our 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.

We are 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 (as defined in the credit agreement) of not more than 4.00 to 1.00; and (2) a Current Ratio (as defined in the credit agreement) of not less than 1.00 to 1.00. As defined in the credit agreement, Total Debt excludes debt discounts and premiums and is net of cash and cash equivalents, EBITDA is for the last four quarters after giving pro forma effect to certain 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 September 30, 2015, the ratio of Total Debt to EBITDA was 2.97 to 1.00 and the Current Ratio was 2.69 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.

In October 2015, we entered into the seventh amendment to the credit agreement governing the revolving credit facility. The revolving credit facility was amended to, among other things, (i) reaffirm the borrowing base at its current level of $685.0 million until the next redetermination and (ii) amend the financial covenant requiring the maintenance of a ratio of Total Debt to EBITDA of not more than 4.00 to 1.00, such that the permissible ratio is increased to 4.75 to 1.00 through December 31, 2016, reducing to 4.375 to 1.00 through December 31, 2017, and returning to 4.00 to 1.00 thereafter.

8.625% Senior Notes

On April 14, 2015, we commenced a cash tender offer for any or all of the outstanding $600.0 million aggregate principal amount of our 8.625% Senior Notes at a price of 104.613% of the principal amount plus accrued and unpaid interest. In connection with the cash tender offer, we also sent a notice of redemption to the trustee for our 8.625% Senior Notes to conditionally call for redemption on May 14, 2015 all of the 8.625% Senior Notes then outstanding at a price of 104.313% of the principal amount plus accrued and unpaid interest, conditioned upon and subject to our receipt of specified net proceeds from one or more securities offerings, which conditions were satisfied. On April 28, 2015, we made an aggregate cash payment of $276.4 million for the $264.2 million aggregate principal amount of 8.625% Senior Notes validly tendered in the tender offer, which excluded accrued interest paid of $0.8 million. We paid $352.6 million to redeem the 8.625% Senior Notes that remained outstanding, which represented $335.8 million of outstanding aggregate principal amount of 8.625% Senior Notes, the redemption premium of $14.5 million, and accrued and unpaid interest of $2.3 million from the last interest payment date up to, but not including, the redemption date. The total price to repurchase and redeem all of the outstanding $600.0 million aggregate principal amount of our 8.625% Senior Notes was $629.8 million. As a result of the cash tender offer and the redemption of our 8.625% Senior Notes, we recorded a loss on extinguishment of debt of approximately $38.1 million during the second quarter of 2015.

6.25% Senior Notes

On April 28, 2015, we closed a public offering of $650.0 million aggregate principal amount of 6.25% Senior Notes due 2023. The 6.25% Senior Notes mature on April 15, 2023, with interest payable semi-annually. Before April 15, 2018, we may redeem all or a portion of our 6.25% Senior Notes at 100% of the principal amount plus a make-whole premium. Thereafter, we may redeem all or a portion of our 6.25% Senior Notes at redemption prices decreasing from

104.688% to 100% of the principal amount on April 15, 2018, plus accrued and unpaid interest.

The indenture governing the 6.25% Senior Notes, which is substantially similar to the indenture governing the 7.50% Senior Notes, contains covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: pay distributions on, purchase or redeem our common stock or other capital stock or redeem our subordinated debt; make investments; incur or guarantee additional indebtedness or issue certain types of equity securities; create certain liens; sell assets; consolidate, merge or transfer all or substantially all of our assets; enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us; engage in transactions with affiliates; and create unrestricted subsidiaries. Such indentures governing our senior notes are also subject to customary events of default, including those related to failure to comply with the terms of the notes and the indenture, certain failures to file reports with the SEC, certain cross defaults of other indebtedness and mortgages and certain failures to pay final judgments.

Equity Offerings

In March 2015, we sold 5.2 million shares of our common stock in an underwritten public offering at a price of $44.75 per share. We used the proceeds of approximately $231.3 million, net of offering costs, to repay borrowings under our revolving credit facility and for general corporate purposes.

In October 2015, we sold 6.3 million shares of our common stock in an underwritten public offering at a price of $37.80 per share. We used a portion of the proceeds of approximately $239.1 million, net of underwriting discounts, to repay borrowings under our revolving credit facility, with the remainder to be used for general corporate purposes, including future potential acquisitions with a primary focus in the Delaware Basin.

Critical Accounting Policies

The preparation of financial statements in conformity with U.S. generally accepted accounting principles 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 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 Annual Report on Form 10-K for the year ended December 31, 2014. 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 oil and gas properties. An impairment recognized in one period may not be reversed in a subsequent period even if higher oil and 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 oil and gas on the first calendar day of each month during the preceding 12-month period prior to the end of the current reporting period. 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.

Due primarily to declines in the average realized prices for sales of oil and gas on the first calendar day of each month during the trailing 12-month period prior to September 30, 2015, the capitalized costs of oil and gas properties exceeded the cost center ceiling resulting in an after-tax impairment in the carrying value of oil and gas properties of $522.7 million ($812.8 million pre-tax) for the three months and nine months ended September 30, 2015. The decrease in average realized prices as described above did not have a significant adverse effect to our proved oil and gas reserve volumes. There were no impairments of oil and gas properties for the three months ended March 31, 2015 or June 30, 2015 or for the corresponding prior year periods.

Based on the first calendar day of each month oil and gas prices available for the 11 months ended November 1, 2015 as well as forecasted costs, we anticipate recording an additional after-tax impairment in the carrying value of oil and gas properties in the fourth quarter of 2015 in the range of $350.0 million to $450.0 million ($538.5 million to $692.3 million pre-tax). 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 applicable to the third and fourth quarters of 2015. We do not expect potential future impairments to have significant adverse effects to our proved oil and gas reserve volumes.

The table below presents results of the full cost ceiling test as of September 30, 2015, along with various pricing scenarios to demonstrate the sensitivity of our cost center ceiling to changes in 12-month average benchmark crude oil and natural gas prices underlying our average realized prices. Prices do not include the impact of crude oil and natural gas derivative instruments. This sensitivity analysis is as of September 30, 2015 and, accordingly, does not consider drilling results, production, changes in oil and gas prices, and changes in future development and operating costs subsequent to September 30, 2015 that may require revisions to our proved reserve estimates and resulting cash flows used in the full cost ceiling test.

	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)
September 30, 2015 Actual	$56.05	$2.18	$—	
Oil and Gas Price Sensitivity				
Oil and Gas +10%	$61.96	$2.50	$250	$250
Oil and Gas -10%	$50.14	$1.87	($247)	($247)
Oil Price Sensitivity				
Oil +10%	$61.96	$2.18	$228	$228
Oil -10%	$50.14	$2.18	($225)	($225)
Gas Price Sensitivity				
Gas +10%	$56.05	$2.50	$23	$23
Gas -10%	$56.05	$1.87	($20)	($20)

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 the deferred tax assets is dependent upon the generation of future taxable income during the periods in which those deferred tax assets would be deductible.

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 September 30, 2015, driven primarily by the full cost ceiling impairment recognized during the third quarter of 2015, 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 fourth quarter of 2015. We also had U.S. federal net operating loss carryforwards of $185.6 million as of December 31, 2014. 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 a valuation allowance against the net deferred tax asset as of September 30, 2015 of $187.6 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 that our net deferred tax assets will be realized include, but are not limited to, cumulative historical pre-tax earnings, improvements in 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 fourth quarter of 2015, we expect to record additional valuation allowance against any deferred tax asset generated by such impairment.

Recent Accounting Pronouncements

See "Note 2. Summary of Significant Accounting Policies - Recent Accounting Pronouncements" 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. For the three months ended September 30, 2015, average realized crude oil prices decreased 53% to $43.91 per Bbl from $94.17 per Bbl for the same period in 2014. Average natural gas prices decreased 38% to $1.61 per Mcf for the third quarter of 2015 from $2.59 per Mcf for the third quarter of 2014.

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" above for discussion of the full cost ceiling test impairment recognized during the third quarter of 2015 and Part I, "Item 1A. Risk Factors—We may record impairments of oil and gas properties that would reduce our shareholders' equity."

We use 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 our drilling and completion capital expenditure program. We do not enter into derivative instruments for speculative or trading purposes. As of September 30, 2015, our commodity derivative instruments consisted of fixed price swaps, costless collars and sold call options, which are described below:

Fixed Price Swaps: We receive 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 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. In exchange for selling these 2017-2020 options, we received upfront proceeds which we used to obtain a higher fixed price on our 2016 fixed price swaps. 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.

The following sets forth a summary of our open crude oil derivative positions at average NYMEX prices as of September 30, 2015:

Period	Type of Contract	Volumes (in Bbls/d)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)
October - December 2015	Costless Collars	16,200	$50.00	$67.34
2016	Costless Collars	5,490	$50.96	$74.73
2016	Fixed Price Swaps	3,000	$60.00	
2017	Sold Call Options	750		$60.00
2018	Sold Call Options	938		$60.00
2019	Sold Call Options	1,125		$62.50
2020	Sold Call Options	1,500		$65.00

On February 11, 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 $40.0 million and $79.9 million were received due to contract settlements during the three months ended September 30, 2015 and nine months ended September 30, 2015, respectively, and is included in the gain on derivatives, net in the consolidated statements of operations. As of September 30, 2015, the fair value of the remaining locked in cash flows is $86.4 million, of which $75.8 million is classified as a current derivative asset and $10.6 million is classified as a noncurrent derivative asset 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. Included in the $42.6 million gain on derivatives, net for the nine months ended September 30, 2015 is an $8.4 million gain representing the increase in fair value of the then-existing crude oil derivative positions from December 31, 2014 to February 11, 2015. The offsetting derivative transactions are not included in the table above.

Additionally, subsequent to entering into the offsetting derivative transactions described above, we entered into costless collars for the periods from March 2015 through December 2016 that will continue to provide us with downside protection at crude oil prices below the weighted average floor prices yet allow us to benefit from an increase in crude oil prices up to the weighted average ceiling prices. During the third quarter of 2015, we sold call options for the years 2017 through 2020 and used the upfront proceeds received from the sale of those call options to obtain a higher price on the 2016 fixed price swaps, as described above. See “Note 13. Subsequent Events - Hedging Activity” for discussion of derivative instruments entered into subsequent to September 30, 2015.

The following sets forth a summary of our natural gas derivative positions at average NYMEX prices as of September 30, 2015:

Period	Type of Contract	Volumes (in MMBtu/d)	Weighted Average Fixed Price ($/MMBtu)
October - December 2015	Fixed Price Swaps	30,000	$4.29

For the three months ended September 30, 2015 and 2014, we recorded in the consolidated statements of operations a gain on derivatives, net of $28.8 million and $71.8 million, respectively. For the nine months ended September 30, 2015 and 2014, we recorded in the consolidated statements of operations a gain on derivatives, net of $42.6 million and $11.2 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. We net our derivative instrument fair value amounts 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 September 30, 2015 and December 31, 2014 totaled $115.3 million and $214.8 million, respectively, and is summarized by counterparty in the table below:

Counterparty	September 30, 2015		December 31, 2014	
Wells Fargo	51	%	37	%
Societe Generale	31	%	26	%
Regions	11	%	8	%
Union Bank	6	%	4	%
Royal Bank of Canada	1	%	1	%
Credit Suisse	—	%	24	%
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 resulting from adverse changes in the fair value of its derivative instruments 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

The statements contained in all parts of this document, including, but not limited to, those relating to the Company's or management's intentions, beliefs, expectations, hopes, projections, assessment of risks, estimations, plans or predictions for the future, including our schedule, targets, estimates or results of future drilling, including the number, timing and results of wells, budgeted wells, increases in wells, the timing and risk involved in drilling follow-up wells, timing and amounts of production, expected working or net revenue interests, planned expenditures, prospects budgeted and other future capital expenditures, risk profile of oil and gas exploration, capital expenditure plans, planned evaluation of prospects, probability of prospects having oil and gas, expected production or reserves, pipeline connections, increases in reserves, acreage, working capital requirements, commodity price risk management activities and the impact on our average realized prices, the availability of expected sources of liquidity to implement the Company's business strategies, future borrowing base matters, full cost ceiling test impairments and valuation allowances, accessibility of borrowings under our revolving credit facility, debt repayments, redemptions or tender offers, future exploration activity, drilling, completion and fracturing of wells, land acquisitions, production rates, forecasted production, growth in production, development of new drilling programs, participation of our industry partners, exploration and development expenditures, the impact of our business strategies, the benefits, results, effects, availability of and results of new and existing joint ventures and sales transactions, receipt of receivables, proceeds from sales, use of proceeds and all and any other statements regarding future operations, financial results, business plans and cash needs and other statements regarding future operations, financial results, business plans and cash needs and other statements that are not historical facts are forward looking statements. When used in this document, the words "anticipate," "estimate," "expect," "may," "project," "plan," "believe" and similar expressions are intended to be among statements that identify forward looking statements. Such statements involve risks and uncertainties, 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, actions and approvals of our partners and parties with whom we have alliances, technological changes, capital requirements, borrowing base determinations and availability under our revolving credit facility, evaluations of the Company by lenders under our revolving credit facility the potential impact of government regulations, including current and proposed legislation and regulations related to hydraulic fracturing, and natural gas drilling, air emissions and climate change, regulatory determinations, litigation, competition, the uncertainty of reserve information, property acquisition risks, availability of equipment, actions by our midstream and other industry partners, weather, availability of financing, market conditions, actions by lenders, our ability to obtain permits and licenses, 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 partners, results of exploration activities, the availability of and completion of land acquisitions, completion and connection of wells, and other factors detailed in the "Item 1A. Risk Factors" and other sections of our Annual Report on Form 10-K for the year ended December 31, 2014 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 forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement and we undertake no obligation 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 Annual Report on Form 10-K for the year ended December 31, 2014. Other than the offsetting derivative transactions described in "Note 10. Derivative Instruments" and "—Volatility of Crude Oil and Natural Gas Prices" in this Form 10-Q, there have been no material changes from the disclosure made in our Annual Report on Form 10-K for the year ended December 31, 2014 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 September 30, 2015 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 September 30, 2015 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, 2014.

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	–	Seventh Amendment to Credit Agreement, dated as of October 30, 2015, among Carrizo Oil & Gas, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lender parties thereto.
*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: November 4, 2015	By: /s/ David L. Pitts Vice President and Chief Financial Officer (Principal Financial Officer)
Date: November 4, 2015	By: /s/ Gregory F. Conaway Vice President and Chief Accounting Officer (Principal Accounting Officer)