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

FORM 10-Q

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

For the quarterly period ended September 30, 2016

OR

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

For the transition period from ____________ to ____________

Commission file number 001-37907

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

DELAWARE	**46-1473923**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
370 17th Street, Suite 5300 Denver, Colorado	**80202**
(Address of principal executive offices)	(Zip Code)

(720) 557-8300
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☐ No ☒ The registrant became subject to such requirements on October 11, 2016 and has filed all reports required since that date.

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ 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	☐	Accelerated filer	☐
Non-accelerated filer	☒	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 ☒

The total number of shares of common stock, par value $0.01 per share, outstanding as of November 7, 2016 was 146,793,564.

EXTRACTION OIL & GAS, INC.
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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q contains "forward-looking statements." All statements, other than statements of historical facts, included herein concerning, among other things, planned capital expenditures, increases in oil and gas production, the number of anticipated wells to be drilled or completed after the date hereof, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as "may," "expect," "estimate," "project," "plan," "believe," "intend," "achievable," "anticipate," "will," "continue," "potential," "should," "could," and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Our results could differ materially from those anticipated in these forward-looking statements as a result of certain factors, including, among others:

- federal and state regulations and laws;
- capital requirements and uncertainty of obtaining additional funding on terms acceptable to us;
- risks and restrictions related to our debt agreements;
- our ability to use derivative instruments to manage commodity price risk;
- realized oil, natural gas and NGL prices;
- a decline in oil, natural gas and NGL production, and the impact of general economic conditions on the demand for oil, natural gas and NGL and the availability of capital;
- unsuccessful drilling and completion activities and the possibility of resulting write-downs;
- geographical concentration of our operations;
- our ability to meet our proposed drilling schedule and to successfully drill wells that produce oil or natural gas in commercially viable quantities;
- shortages of oilfield equipment, supplies, services and qualified personnel and increased costs for such equipment, supplies, services and personnel;
- adverse variations from estimates of reserves, production, production prices and expenditure requirements, and our inability to replace our reserves through exploration and development activities;
- incorrect estimates associated with properties we acquire relating to estimated proved reserves, the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs of such acquired properties;
- hazardous, risky drilling operations, including those associated with the employment of horizontal drilling techniques, and adverse weather and environmental conditions;
- limited control over non-operated properties;
- title defects to our properties and inability to retain our leases;
- our ability to successfully develop our large inventory of undeveloped operated and non-operated acreage;
- our ability to retain key members of our senior management and key technical employees;

- constraints in the DJ Basin of Colorado with respect to gathering, transportation and processing facilities and marketing;
- risks relating to managing our growth, particularly in connection with the integration of significant acquisitions;
- impact of environmental, health and safety, and other governmental regulations, and of current or pending legislation;
- changes in tax laws;
- effects of competition; and
- seasonal weather conditions.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil and natural gas that are ultimately recovered.

In addition to the other information set forth in this Quarterly Report on Form 10-Q, you should carefully consider the risk factors and other cautionary statements described under the heading "Risk Factors" included in our Final Prospectus and in our other filings with SEC, which could materially affect our businesses, financial condition, or future results. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition, or future results. There has been no material changes in our risk factors from those described in the Final Prospectus.

All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements in this section and elsewhere in this Quarterly Report on Form 10-Q. Except as required by law, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

GLOSSARY OF OIL AND GAS TERMS

Unless indicated otherwise or the context otherwise requires, references in this report to the "Company," “XOG,” "us," "we," "our," or "ours" or like terms refer to Extraction Oil & Gas, Inc. following the completion of our initial public offering on October 17, 2016, as described under “Note 8—Members’ Equity—Initial Public Offering.” When used in the historical context, the "Company," “Holdings,” "us," "we," "our" and "ours" or like terms refer to Extraction Oil & Gas Holdings, LLC and its subsidiaries. Holdings is our accounting predecessor, for which we present the condensed consolidated financial statements in this report.

The terms defined in this section are used throughout this 10-Q:

"Bbl" means one stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

"BBtu" One billion Btus.

"BOE" means barrels of oil equivalent. Oil equivalents are determined using the ratio of six Mcf of gas (including gas liquids) to one Bbl of oil.

"BOE/d" means BOE per day.

"Btu" means one British thermal unit—a measure of the amount of energy required to raise the temperature of a one-pound mass of water one degree Fahrenheit at sea level.

"CIG" means Colorado Interstate Gas.

"Completion" means the installation of permanent equipment for the production of oil or natural gas.

"Exploratory well" means a well drilled either (a) in search of a new and as yet undiscovered pool of oil or gas or (b) with the hope of significantly extending the limits of a pool already developed (also known as a "wildcat well").

"Field" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

"Gas" or "Natural gas" means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain liquids.

"Gross Acres" or "Gross Wells" means the total acres or wells, as the case may be, in which we have a working interest.

“Henry Hub” means Henry Hub index. Natural gas distribution point where prices are set for natural gas futures contracts traded on the NYMEX.

"Horizontal drilling" means a wellbore that is drilled laterally.

"Leases" means full or partial interests in oil or gas properties authorizing the owner of the lease to drill for, produce and sell oil and natural gas in exchange for any or all of rental, bonus and royalty payments. Leases are generally acquired from private landowners (fee leases) and from federal and state governments on acreage held by them.

"MBbl" One thousand barrels of oil, condensate or NGLs.

MBoe" One thousand barrels of oil equivalent. Oil equivalents are determined using the ratio of six Mcf of gas (including gas liquids) to one Bbl of oil.

"Mcf" is an abbreviation for "1,000 cubic feet," which is a unit of measurement of volume for natural gas.

"MMBtu" One million Btus.

"MMcf" is an abbreviation for "1,000,000 cubic feet," which is a unit of measurement of volume for natural gas.

"Net Acres" or "Net Wells" is the sum of the fractional working interests owned in gross acres or wells, as the case may be, expressed as whole numbers and fractions thereof.

"Net revenue interest" means all of the working interests less all royalties, overriding royalties, non-participating royalties, net profits interest or similar burdens on or measured by production from oil and natural gas.

"NGL" means natural gas liquids.

"NYMEX" means New York Mercantile Exchange.

"Proved developed reserves" means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

"Proved reserves" means the estimated quantities of oil, gas and gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

"Proved undeveloped reserves" means reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

"Recompletion" means the completion for production from an existing wellbore in a formation other than that in which the well has previously been completed.

"Reservoir" means a porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

"Royalty" means the share paid to the owner of mineral rights, expressed as a percentage of gross income from oil and natural gas produced and sold unencumbered by expenses relating to the drilling, completing and operating of the affected well.

"Royalty interest" means an interest in an oil and natural gas property entitling the owner to shares of oil and natural gas production, free of costs of exploration, development and production operations.

"Working interest" means an interest in an oil and natural gas lease entitling the holder at its expense to conduct drilling and production operations on the leased property and to receive the net revenues attributable to such interest, after deducting the landowner's royalty, any overriding royalties, production costs, taxes and other costs.

"WTI" means the price of West Texas Intermediate oil on the NYMEX.

PART I. FINANCIAL INFORMATION
ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS HOLDINGS, LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands, except unit data)
(Unaudited)

	September 30, 2016	December 31, 2015
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,386	$ 97,106
Accounts receivable		
Trade	19,011	27,927
Oil, natural gas and NGL sales	24,444	15,938
Inventory and prepaid expenses	5,695	7,938
Commodity derivative asset	532	68,885
Total Current Assets	51,068	217,794
Property and Equipment (successful efforts method), at cost:		
Proved oil and gas properties	1,405,817	1,128,022
Unproved oil and gas properties	318,267	374,194
Wells in progress	61,064	59,416
Less: accumulated depletion, depreciation and amortization	(341,050)	(181,382)
Net oil and gas properties	1,444,098	1,380,250
Other property and equipment, net of accumulated depreciation (Note 2)	29,346	30,402
Net Property and Equipment	1,473,444	1,410,652
Non-Current Assets:		
Cash held in escrow	42,000	—
Deferred equity issuance costs	5,126	942
Commodity derivative asset	—	2,906
Other non-current assets	1,767	1,846
Total Non-Current Assets	48,893	5,694
Total Assets	$ 1,573,405	$ 1,634,140
LIABILITIES AND MEMBERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 76,982	$ 111,127
Revenue payable	48,980	38,752
Production taxes payable	27,149	19,061
Commodity derivative liability	21,776	—
Accrued interest payable	8,792	450
Asset retirement obligations	3,742	952
Total Current Liabilities	187,421	170,342
Non-Current Liabilities:		
Credit facility	89,000	225,000
Second Lien Notes, net of unamortized debt discount and debt issuance costs (Note 4)	—	412,790
Senior Notes, net of unamortized debt issuance costs (Note 4)	537,601	—
Production taxes payable	23,406	25,275
Commodity derivative liability	6,727	—
Other non-current liabilities	3,523	3,086
Asset retirement obligations	49,492	43,415
Total Non-Current Liabilities	709,749	709,566
Commitments and Contingencies—Note 11		
Total Liabilities	897,170	879,908
Members' Equity:		
Preferred tranche C units; unlimited units authorized; 115,706,938 units issued and outstanding	370,418	250,338
Tranche A units; unlimited units authorized; 237,434,889 units issued and outstanding	513,451	501,128
Retained earnings (deficit)	(207,634)	2,766
Total Members' Equity	676,235	754,232
Total Liabilities and Members' Equity	$ 1,573,405	$ 1,634,140

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART
OF THESE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS HOLDINGS, LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per unit data)
(Unaudited)

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Revenues:				
Oil sales	$ 51,760	$ 37,304	$ 135,896	$ 114,768
Natural gas sales	12,792	7,472	27,730	17,707
NGL sales	8,350	4,070	19,773	9,153
Total Revenues	72,902	48,846	183,399	141,628
Operating Expenses:				
Lease operating expenses	15,480	7,493	40,819	18,806
Production taxes	6,186	4,874	16,935	12,798
Exploration expenses	5,985	1,911	14,735	6,763
Depletion, depreciation, amortization and accretion	46,680	40,880	141,317	100,170
Impairment of long lived assets	467	—	23,350	9,525
Other operating expenses	—	696	891	2,353
Acquisition transaction expenses	345	—	345	6,000
General and administrative expenses	20,071	8,568	35,189	25,437
Total Operating Expenses	95,214	64,422	273,581	181,852
Operating Loss	(22,312)	(15,576)	(90,182)	(40,224)
Other Income (Expense):				
Commodity derivatives gain (loss)	16,225	46,886	(62,424)	38,478
Interest expense	(31,216)	(12,682)	(57,914)	(36,350)
Other income	36	22	120	36
Other Income (Expense)	(14,955)	34,226	(120,218)	2,164
Net Income (Loss)	(37,267)	18,650	(210,400)	$ (38,060)
Income (Loss) per Unit				
Basic	$ (0.11)	$ 0.07	$ (0.63)	$ (0.14)
Diluted	$ (0.11)	$ 0.07	$ (0.63)	$ (0.14)
Weighted Average Units Outstanding				
Basic	349,014	279,896	332,377	266,844
Diluted	349,014	286,891	332,377	266,844
Pro Forma Information (unaudited):				
Pro forma income (loss)	$ (37,267)	$ 18,650	$ (210,400)	$ (38,060)
Pro forma provision for income tax (expense) benefit	14,161	(7,087)	79,952	14,463
Pro forma net income (loss)	$ (23,106)	$ 11,563	$ (130,448)	$ (23,597)
Pro forma net income (loss) per unit				
Basic	$ (0.07)	$ 0.04	$ (0.39)	$ (0.09)
Diluted	$ (0.07)	$ 0.04	$ (0.39)	$ (0.09)
Weighted average pro forma units outstanding				
Basic	349,014	279,896	332,377	266,844
Diluted	349,014	286,891	332,377	266,844

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS HOLDINGS, LLC
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN MEMBERS' EQUITY
(In thousands)
(Unaudited)

	Tranche A Units	Preferred Tranche C Units	Amount	(Accumulated Deficit) Retained Earnings	Total Members' Equity
Balance at January 1, 2015	227,903	—	$ 495,158	$ 50,030	$ 545,188
Units issued	—	68,723	223,350	—	223,350
Units repurchased	—	—	—	—	—
Unit issuance costs	—	—	(4,649)	—	(4,649)
Restricted stock units issued	2,514	—	—	—	—
Unit-based compensation	—	—	4,583	—	4,583
Net loss	—	—	—	(38,060)	(38,060)
Balance at September 30, 2015	230,417	68,723	$ 718,442	$ 11,970	$ 730,412
Balance at January 1, 2016	231,101	78,444	$ 751,466	$ 2,766	$ 754,232
Units issued	—	37,345	121,370	—	121,370
Units repurchased	(1,327)	(82)	(8,429)	—	(8,429)
Settlement of promissory notes issued to officers	—	—	5,562	—	5,562
Unit issuance costs	—	—	(1,022)	—	(1,022)
Restricted stock units issued	7,661	—	—	—	—
Unit-based compensation	—	—	14,922	—	14,922
Net loss	—	—	—	(210,400)	(210,400)
Balance at September 30, 2016	237,435	115,707	$ 883,869	$ (207,634)	$ 676,235

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS HOLDINGS, LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)
(Unaudited)

	For the Nine Months Ended September 30, 2016	For the Nine Months Ended September 30, 2015
Cash flows from operating activities:		
Net loss	$ (210,400)	$ (38,060)
Reconciliation of net loss to net cash provided by operating activities:		
Depletion, depreciation, amortization and accretion	141,317	100,170
Abandonment and impairment of unproved properties	3,331	6,214
Impairment of long lived assets	23,350	9,525
Non-cash acquisition transaction expenses	—	6,000
Amortization of debt issuance costs and debt discount	18,330	3,081
Deferred rent	600	212
Commodity derivatives (gain) loss	62,424	(38,478)
Settlements on commodity derivatives	43,015	39,929
Premiums paid on commodity derivatives	(611)	(2,350)
Unit-based compensation	14,922	4,583
Changes in current assets and liabilities:		
Accounts receivable—trade	3,889	(2,813)
Accounts receivable—oil, natural gas and NGL sales	(8,506)	(8,352)
Prepaid expenses	(273)	(281)
Accounts payable and accrued liabilities	(18,242)	33,585
Revenue payable	10,228	10,888
Production taxes payable	6,219	11,774
Accrued interest payable	8,342	11,704
Asset retirement expenditures	(372)	(1,770)
Net cash provided by operating activities	97,563	145,561
Cash flows from investing activities:		
Oil and gas property additions	(223,684)	(288,060)
Acquired oil and gas properties	(13,674)	(120,524)
Sale of property and equipment	2,148	—
Other property and equipment additions	(3,336)	(20,086)
Cash held in escrow	(42,000)	10,071
Net cash used in investing activities	(280,546)	(418,599)
Cash flows from financing activities:		
Borrowings under credit facility	60,000	100,000
Repayments under credit facility	(196,000)	—
Proceeds from the issuance of Senior Notes	550,000	—
Repayments of Second Lien Notes	(430,000)	—
Proceeds from the issuance of units	121,370	223,350
Repurchase of units	(2,867)	—
Debt issuance costs	(13,189)	(1,874)
Unit and deferred equity issuance costs	(2,051)	(4,524)
Net cash provided by financing activities	87,263	316,952
Increase (decrease) in cash and cash equivalents	(95,720)	43,914
Cash and cash equivalents at beginning of period	97,106	79,025
Cash and cash equivalents at end of the period	$ 1,386	$ 122,939
Supplemental cash flow information:		
Property and equipment included in accounts payable and accrued liabilities	$ 53,371	$ 81,444
Acquisition transaction expenses paid through oil and gas properties	$ —	$ 6,000
Cash paid for interest	$ 30,531	$ 25,677
Cash paid for Second Lien Notes prepayment penalty	$ 4,300	$ —
Noncash settlement of promissory notes issued to officers	$ 5,562	$ —

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS HOLDINGS, LLC
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Organization

Description of Operations

Extraction Oil & Gas Holdings, LLC, a Delaware limited liability company was formed on May 29, 2014 by PRE Resources, LLC (“PRL”) as a holding company with no independent operations apart from its ownership of the subsidiaries described below. PRL was formed in May 2012 to invest in oil and gas properties in Michigan, California, Wyoming, North Dakota and Colorado.

Extraction Oil & Gas, LLC (“Extraction”), formerly a wholly-owned subsidiary of PRL, was a wholly-owned subsidiary of Holdings. Extraction was formed on November 14, 2012, as a Delaware limited liability company and is focused on the acquisition, development and production of oil, natural gas and natural gas liquids (“NGL”) reserves in the Rocky Mountains, primarily in the Wattenberg Field of the Denver-Julesburg Basin (the “DJ Basin”) of Colorado.

Concurrent with the formation of Holdings, PRL contributed all of its membership interests in Extraction, to Holdings and distributed all of its interests in Holdings to its members in a pro rata distribution (the “Reorganization”). As all power and authority to control the core functions of Holdings and Extraction were controlled by PRL, the Reorganization was accounted for as a reorganization of entities under common control and the assets and liabilities of Extraction were recorded at Extraction’s historical costs.

At the Reorganization, Yorktown Energy Partners (“Yorktown”) controlled Holdings through ownership of 76.1% of its membership interests. The remaining 23.9% of Holdings’ membership interests was owned by certain members of management and other third-party investors. Immediately after the Reorganization, Holdings completed an offering of its membership units (see *Note 8—Members’ Equity*). Following the membership offering, Yorktown controlled 51.8% of Holdings through three funds: Yorktown Energy Fund IX, LP, Yorktown Energy Fund X, LP, and Yorktown Extraction Co-Investment Partners, LP. Yorktown Energy Fund XI, LP invested in the April and June 2016 equity offering.

Subsequent to the membership offering described above, the Company issued additional membership interests (see *Note 8—Members’ Equity*). As a result, Yorktown owned 52.0% and certain members of management and other third-party investors owned 48.0% of Holdings’ at September 30, 2016.

In connection with the Company’s initial public offering (the “IPO” or the “Offering”), Extraction converted from a Delaware limited liability company to XOG, a Delaware corporation. In connection with the closing of the IPO on October 17, 2016, Holdings was merged with and into XOG, and XOG was the surviving entity to the merger. The merger was treated as a reorganization of entities under common control. As part of Holdings' merger with and into XOG, all of Holdings' other subsidiaries became direct or indirect subsidiaries of XOG. XOG is a public company listed for trading on the NASDAQ Global Select Market (“NASDAQ”) under the symbol “XOG”. Please refer to Note 8 – Members’ Equity for further information on the IPO.

XTR Midstream, LLC (“XTR”) was a wholly-owned subsidiary of Holdings and is now a wholly-owned subsidiary of XOG. XTR was formed on September 10, 2014, as a Delaware limited liability company and is designing midstream assets to gather and process crude oil and gas production in the DJ Basin of Colorado.

7N, LLC (“7N”) was also a wholly-owned subsidiary of Holdings and now is a wholly-owned subsidiary of XOG. 7N, LLC was formed on September 10, 2014, as a Delaware limited liability company to acquire certain real property and rights-of-way to support the build-out of XTR’s gathering and processing system.

Mountaintop Minerals, LLC (“Mountaintop”) was also a wholly-owned subsidiary of Holdings and is now a wholly-owned subsidiary of XOG. Mountaintop was formed on March 10, 2015, as a Delaware limited liability company to engage in the acquisition of minerals, primarily in the DJ Basin of Colorado.

8 North, LLC (“8 North”) was also a wholly-owned subsidiary of Holdings and is now a wholly-owned subsidiary of XOG. 8 North was formed on April 29, 2015, as a Delaware limited liability company and was assigned certain leases in Boulder and Weld Counties previously owned by Extraction Oil and Gas, LLC. 8 North, LLC was formed to engage in the development of oil and gas leases currently categorized as unproved with a specific focus on Northern Colorado.

XOG Services, LLC was also a wholly-owned subsidiary of Holdings and now is a wholly-owned subsidiary of XOG. XOG Services, LLC was formed on November 13, 2015, as a Delaware limited liability company to administer payroll and other general and administrative functions beginning in 2016 for all Holdings’ subsidiaries.

Extraction Finance Corp. was also a wholly-owned subsidiary of Holdings and is now a wholly-owned subsidiary of XOG. Extraction Finance Corp. was formed on June 20, 2016, as a Delaware corporation to facilitate the Company’s Senior Notes Offering. For additional discussion on the Senior Notes Offering please refer to *Note 4—Long-Term Debt.*

Note 2—Basis of Presentation and Significant Accounting Policies

Basis of Presentation

The unaudited condensed consolidated financial statements include the accounts of the Company, including its wholly-owned subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation. The financial statements included herein were prepared from the records of the Company in accordance with generally accepted accounting principles in the United States (“GAAP”). In the opinion of management, all adjustments, consisting primarily of normal recurring accruals that are considered necessary for a fair statement of the consolidated financial information, have been included. However, operating results for the period presented are not necessarily indicative of the results that may be expected for a full year. These unaudited financial statements should be read in conjunction with our audited financial statements and notes for the year ended December 31, 2015, presented in our final prospectus, dated October 11, 2016 and filed with the Securities and Exchange Commission (“SEC”) pursuant to Rule 424(b)(4) of the Securities Act of 1933, as amended, on October 13, 2016.

Use of Estimates in the Preparation of Financial Statements

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant areas requiring the use of assumptions, judgments and estimates include (1) oil and gas reserves; (2) cash flow estimates used in impairment testing of oil and gas properties; (3) depreciation, depletion and amortization; (4) asset retirement obligations; (5) assigning fair value and allocating purchase price in connection with business combinations; (6) accrued revenue and related receivables; (7) valuation of commodity derivative instruments; (8) accrued liabilities; and (9) valuation of unit based payments. Although management believes these estimates are reasonable, actual results could differ from these estimates. The Company evaluates its estimates on an on-going basis and bases its estimates on historical experience and on various other assumptions the Company believes to be reasonable under the circumstances. Although actual results may differ from these estimates under different assumptions or conditions, the Company believes its estimates are reasonable.

Cash and Cash Equivalents

Cash and cash equivalents consist of all highly liquid investments that are readily convertible into cash and have original maturities of three months or less when purchased.

Cash Held in Escrow

Cash held in escrow includes a deposit for the purchase of certain oil and gas properties as required under the related purchase and sale agreements. In October 2016, the $42.0 million of cash held in escrow as of September 30, 2016 was released at the closing of the acquisition. Please refer to *Note 3—Acquisitions* for further information.

Accounts Receivable

The Company records estimated oil and gas revenue receivable from third parties at its net revenue interest. The Company also reflects costs incurred on behalf of joint interest partners in accounts receivable. The Company generally has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. On an on-going basis, management reviews accounts receivable amounts for collectability and records its allowance for uncollectible receivables under the specific identification method. The Company did not record any allowance for uncollectible receivables as of or for the nine months ended September 30, 2016 and 2015.

Credit Risk and Other Concentrations

The Company's cash and cash equivalents are exposed to concentrations of credit risk. The Company manages and controls this risk by investing these funds with major financial institutions. The Company often has balances in excess of the federally insured limits.

The Company sells oil, natural gas and natural gas liquids to various types of customers, including pipelines and refineries. Credit is extended based on an evaluation of the customer's financial conditions and historical payment record. The future availability of a ready market for oil, natural gas and NGL depends on numerous factors outside the Company's control, none of which can be predicted with certainty. For the three and nine months ended September 30, 2016 and 2015, the Company had the following major customers that exceeded 10% of total oil, natural gas and NGL revenues. The Company does not believe the loss of any single purchaser would materially impact its operating results because crude oil, natural gas and NGLs are fungible products with well-established markets and numerous purchasers.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Customer A	28 %	29 %	34 %	30 %
Customer B	20 %	21 %	25 %	15 %
Customer C	19 %	19 %	17 %	16 %
Customer D	— %	17 %	2 %	29 %
Customer E	19 %	— %	8 %	— %

At September 30, 2016, the Company had commodity derivative contracts with six counterparties. The Company does not require collateral or other security from counterparties to support derivative instruments; however, to minimize the credit risk in derivative instruments, it is the Company's policy to enter into derivative contracts only with counterparties that are credit worthy financial institutions deemed by management as competent and competitive market-makers. Additionally, the Company uses master netting agreements to minimize credit-risk exposure. The credit worthiness of the Company's counterparties is subject to periodic review. Three of the six counterparties to the derivative instruments are highly rated entities with corporate ratings at A3 classifications or above by Moody's. The other three counterparties had a corporate rating of Baa1 by Moody's. For the three and nine months ended September 30, 2016 and 2015, the Company did not incur any losses with respect to counterparty contracts. None of the Company's existing derivative instrument contracts contains credit-risk related contingent features.

Inventory and Prepaid Expenses

The Company records well equipment inventory at the lower of cost or market value. Prepaid expenses are recorded at cost. Inventory and prepaid expenses are comprised of the following (in thousands):

	September 30, 2016	December 31, 2015
Well equipment inventory	$ 3,950	$ 6,238
Prepaid expenses	1,745	1,700
	$ 5,695	$ 7,938

Oil and Gas Properties

The Company follows the successful efforts method of accounting for oil and gas properties. Under this method of accounting, all property acquisition costs and development costs are capitalized when incurred and depleted on a units-of-production basis over the remaining life of proved reserves and proved developed reserves, respectively. At September 30, 2016 and 2015, the Company excluded $61.1 million and $67.8 million of capitalized costs from depletion related to wells in progress, respectively. For the three and nine months ended September 30, 2016, the Company recorded depletion expense on capitalized oil and gas properties of $44.8 million and $135.6 million, respectively, as compared to $38.9 million and $95.9 million for the three and the nine months ended September 30, 2015, respectively.

The costs of exploratory wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) sufficient progress in assessing the reserves and the economic and operating viability of the project has been made. The status of suspended well costs is monitored continuously and reviewed at each period end. Due to the capital-intensive nature and the geological characteristics of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and the economics associated with making a determination of its commercial viability. As of December 31, 2015, the Company had approximately $17.3 million in suspended well costs recorded, all capitalized less than one year, related to four exploratory wells in the Northern field. The suspended well costs were included in wells in progress at December 31, 2015. These exploratory well costs were pending further engineering evaluation and analysis to determine if economic quantities of oil and gas reserves have been discovered. At June 30, 2016, the Company completed its evaluation and moved $21.8 million of these suspended well costs to proved oil and gas properties based on the determination of proved reserves. As of September 30, 2016, the Company did not have any suspended well costs as the analysis on economic and operating viability of the project was complete.

Geological and geophysical costs are expensed as incurred. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. Amounts of seismic costs capitalized are based on only those blocks of data used in determining development well locations. To the extent that a seismic project covers areas of both developmental and exploratory drilling, those seismic costs are proportionately allocated between development costs and exploration expense.

The Company capitalizes interest, if debt is outstanding, during drilling operations in its exploration and development activities. For the three and nine months ended September 30, 2016, the Company capitalized interest of $1.2 million and $3.6 million, respectively, as compared to $1.4 million and $4.1 million for the three and nine months ended September 30, 2015, respectively.

Impairment of Oil and Gas Properties

Proved oil and gas properties are reviewed for impairment annually or when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. For each of our fields, the Company estimates the expected future cash flows of its oil and gas properties and compares these undiscounted cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will write down the carrying amount of the oil and gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures and discount rates commensurate with the risk associated with realizing the projected cash flows. Impairment expense for proved oil and gas properties is reported in impairment of long lived assets in the consolidated statements of operations, which increased accumulated depletion, depreciation and amortization. No impairment expense was recognized for the three months ended September 30, 2016 on proved oil and gas properties. For the nine months ended September 30, 2016, the Company recognized $22.5 million in impairment expense on proved oil and gas properties. No impairment expense was recognized for the three months ended September 30, 2015 on proved oil and gas properties. For the nine months ended September 30, 2015, the Company recognized $9.5 million in impairment expense on proved oil and gas properties. The impairment expense for the nine months ended September 30, 2016 and 2015 is related to impairment of the assets in the Company's Northern field. The future undiscounted cash flows did not exceed its carrying amount associated with its proved oil and gas properties in its Northern field and it was determined that the proved oil and gas properties had no remaining fair value. Therefore, the full net book value of these proved oil and gas properties were impaired at June 30, 2016 and 2015.

Unproved oil and gas properties consist of costs to acquire unevaluated leases as well as costs to acquire unproved reserves. The Company evaluates significant unproved oil and gas properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage. When successful wells are drilled on undeveloped leaseholds, unproved property costs are reclassified to proved properties and depleted on a unit-of-production basis. Impairment expense and lease extension payments for unproved properties is reported in exploration expenses in the consolidated statements of operations. As a result of the abandonment and impairment of unproved properties, the Company recognized $0.4 million and $3.3 million in impairment expense for the three and nine months ended September 30, 2016, respectively, as compared to $1.7 million and $6.2 million for the three and nine months ended September 30, 2015, respectively. As result of lease extension payments, the Company recognized $5.6 and $11.4 million of expense for the three and nine months ended September 30, 2016, respectively, as compared to $0.2 million and $0.6 million for the three and nine months ended September 30, 2015, respectively.

Other Property and Equipment

Other property and equipment consists of (i) XTR assets such as rights of way, pipelines, equipment and engineering costs, (ii) compressors used in Extraction's oil and gas operations, (iii) land to be used in the future development of the Company's gas plant, compressor stations, central tank batteries, and disposal well facilities and (iv) other property and equipment including, office furniture and fixtures, leasehold improvements and computer hardware and software. Impairment expense for other property and equipment is reported in impairment of long lived assets in the consolidated statements of operations. The Company recognized $0.4 million in impairment expense related to midstream facilities for the nine months ended September 30, 2016, which increased accumulated depreciation recognized in other property and equipment, net of accumulated depreciation. The Company recognized this impairment expense as the result of contraction in the local oil and gas industry's near term growth profile, therefore decreasing the need and support for a specifically proposed gas processing facility. No impairment expense for other property and equipment was recorded for the three months ended September 30, 2016. No impairment expense for other property and equipment was recorded for the three and nine months ended September 30, 2015. Other property and equipment is recorded at cost and depreciated using the straight-line method over their estimated useful lives ranging from three to 25 years. Other property and equipment is comprised of the following (in thousands):

	September 30, 2016	December 31, 2015
Rental equipment	$ 2,910	$ 2,910
Land	12,978	14,778
Midstream facilities	12,623	10,783
Office leasehold improvements	4,360	3,967
Other	4,722	4,073
Less: accumulated depreciation	(8,247)	(6,109)
	$ 29,346	$ 30,402

Deferred Lease Incentives

All incentives received from landlords for office leasehold improvements are recorded as deferred lease incentives and amortized over the term of the respective lease on a straight-line basis as a reduction of rental expense.

Debt Discount Costs

The $430.0 million in Second Lien Notes issued in May of 2014 were issued at a 1.5% original issue discount ("OID") and the debt discount of $6.5 million has been recorded as a reduction of the Second Lien Notes. The debt discount costs related to Second Lien Notes are amortized to interest expense using the effective interest method over the term of the debt.

Debt Issuance Costs

Debt issuance costs include origination, legal, engineering, and other fees incurred to issue the debt in connection with the Company's credit facility, Second Lien Notes and Senior Notes. Debt issuance costs related to the credit facility are amortized to interest expense on a straight-line basis over the respective borrowing term. Debt issuance costs related to the Second Lien Notes and Senior Notes are amortized to interest expense using the effective interest method over the term of the debt.

Deferred Equity Issuance Costs

In conjunction with the IPO, costs incurred related to the IPO are capitalized as deferred equity issuance costs until the common shares are issued or the potential offering is terminated. Upon issuance of common shares, these costs will be offset against the proceeds received. Offering costs include direct and incremental costs related to the offering, such as legal fees and related costs associated with the executed IPO.

Commodity Derivative Instruments

The Company has entered into commodity derivative instruments to reduce the effect of price changes on a portion of the Company's future oil and natural gas production. The commodity derivative instruments are measured at fair value and are included in the accompanying balance sheets as commodity derivative assets and commodity derivative liabilities. The Company has not designated any of the derivative contracts as fair value or cash flow hedges. Therefore, the Company does not apply hedge accounting to the commodity derivative instruments. Net gains and losses on commodity derivative instruments are recorded based on the changes in the fair values of the derivative instruments. Net gains and losses on commodity derivative instruments are recorded in the commodity derivative gain (loss) line on the consolidated statements of operations. The Company's cash flow is only impacted when the actual settlements under the commodity derivative contracts result in making or receiving a payment to or from the counterparty. These settlements under the commodity derivative contracts are reflected as operating activities in the Company's consolidated statements of cash flows.

The Company's valuation estimate takes into consideration the counterparties' credit worthiness, the Company's credit worthiness, and the time value of money. The consideration of these factors result in an estimated exit-price for each derivative asset or liability under a market place participant's view. Management believes that this approach provides a reasonable, non-biased, verifiable, and consistent methodology for valuing commodity derivative instruments. Please refer to *Note 5—Commodity Derivative Instruments* for additional discussion on commodity derivative instruments.

Fair Value of Financial Instruments

The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable, accounts payable, commodity derivative instruments (discussed above) and long-term debt. The carrying values of cash and cash equivalents, accounts receivable and accounts payable are representative of their fair values due to their short-term maturities. The carrying amount of the Company's credit facility approximates fair value as it bears interest at variable rates over the term of the loan. The Company's Second Lien Notes and Senior Notes are recorded at cost and the fair value is disclosed in *Note 7—Fair Value Measurements*. Considerable judgment is required to develop estimates of fair value. The estimates provided are not necessarily indicative of the amounts the Company would realize upon the sale or refinancing of such instruments.

Asset Retirement Obligation

The Company recognizes estimated liabilities for future costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time the Company makes the decision to complete the well or a well is acquired. For additional discussion on asset retirement obligations please refer to *Note 6—Asset Retirement Obligations.*

Environmental Liabilities

The Company is subject to federal, state and local environmental laws and regulations. These laws regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed.

Liabilities for expenditures of a non-capital nature are recorded when environmental assessments and/or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted values unless the timing of cash payments for the liability or component is fixed or determinable. Management has determined that no environmental liabilities existed as of September 30, 2016.

Revenue Recognition

Revenues from the sale of oil, natural gas and NGLs are recognized when the product is delivered at a fixed or determinable price, title has transferred, and collectability is reasonably assured and evidenced by a contract. The Company recognizes revenues from the sale of oil, natural gas and NGLs using the sales method of accounting, whereby revenue is recorded based on the Company's share of volume sold, regardless of whether the Company has taken its proportional share of volume produced. A receivable or liability is recognized only to the extent that the Company has an imbalance on a specific property greater than the expected remaining proved reserves. There were no material imbalances at September 30, 2016 and September 30, 2015.

Unit-Based Payments

The Company has granted restricted unit awards ("RUAs") to certain employees and nonemployee consultants of the Company, which therefore required the Company to recognize the expense in its financial statements. All unit-based payments to employees are measured at fair value on the grant date and expensed over the relevant service period. Unit-based payments to nonemployees are measured at fair value at each financial reporting date and expensed over the period of performance, such that aggregate expense recognized is equal to the fair value of the restricted units on the date performance is completed. All unit-based payment expense is recognized using the straight-line method and is included within general and administrative expenses in the consolidated statements of operations. Please refer to *Note 9—Unit-Based Compensation* for additional discussion on unit-based payments.

Income Taxes

As of September 30, 2016, the Company was organized as a Delaware limited liability company and is treated as a flow-through entity for U.S. federal and state income tax purposes. As a result, the Company's net taxable income and any related tax credits are passed through to the members and are included in their tax returns even though such net taxable income or tax credits may not have actually been distributed.

Unaudited Pro Forma Income Taxes

In October 2016, the Company completed its IPO and the financial statements have been prepared to present unaudited pro forma entity level income tax expense. In connection with the IPO, Extraction converted from a Delaware limited liability company into XOG, a Delaware corporation, which will be taxed as a corporation under the Internal Revenue Code of 1986, as amended, and Holdings merged with and into XOG. Accordingly, a pro forma income tax provision has been disclosed as if the Company was a taxable corporation for all periods presented. The Company has computed pro forma entity-level income tax expense using an estimated effective rate of 38%, inclusive of all applicable U.S. federal, state and local income taxes.

Unaudited Pro Forma Earnings Per Unit

The Company has presented pro forma earnings per unit for the most recent period. Pro forma basic and diluted income (loss) per unit was computed by dividing pro forma net income (loss) attributable to the Company by the number of units attributable issued and outstanding for the periods ended September 30, 2016.

Segment Reporting

The Company operates in only one industry segment, which is the exploration and production of oil, natural gas and NGLs and related midstream activities. The Company's wholly-owned subsidiary, XTR, is currently in the design phase and no revenue generating activities have commenced. All of the Company's operations are conducted in one geographic area of the United States. All revenues are derived from customers located in the United States.

Recent Accounting Pronouncements

The accounting standard-setting organizations frequently issue new or revised accounting rules. The Company regularly reviews new pronouncements to determine their impact, if any, on its financial statements.

In August 2016, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2016-15, which addresses eight specific cash flow issues, including presentation of debt prepayments or debt extinguishment costs, with the objective of reducing the existing diversity in practice. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. Early adoption is permitted, including an adoption in an interim period, with a required retrospective application to each period presented. The Company is currently evaluating this new standard to determine the potential impact to its financial statements and related disclosures.

In March 2016, the FASB issued ASU No. 2016-09, which simplifies the accounting for share-based payment award transactions, including: (a) income tax consequences; (b) classification of awards as either equity or liabilities; and (c) classification on the consolidated statements of cash flows. ASU 2016-09 is effective for public companies for annual reporting periods beginning after December 15, 2016, including interim periods within those fiscal years. Early adoption is permitted in any interim period or annual period with any adjustment reflected as of the beginning of the fiscal year of adoption. The Company is currently evaluating this new standard to determine the potential impact to its financial statements and related disclosures.

In March 2016, the FASB issued ASU No. 2016-06, which clarifies the requirements to assess whether an embedded put or call option is clearly and closely related to the debt host, solely in accordance with the four-step decision sequence in FASB ASC Topic 815, *Derivatives and Hedging*, as amended by ASU 2016-06. This standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016 and should be applied using a modified retrospective approach. Early adoption is permitted. The Company is currently evaluating the impact of adopting ASU 2016-06, however the standard is not expected to have a significant effect on its consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, which requires lessee recognition on the balance sheet of a right-of-use asset and a lease liability, initially measured at the present value of the lease payments. It further requires recognition in the income statement of a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a generally straight-line basis. Finally, it requires classification of all cash payments within operating activities in the statements of cash flows. It is effective for fiscal years commencing after December 15, 2018 and early adoption is permitted. The Company is currently evaluating the impact this new standard will have on its financial statements.

In September 2015, the FASB issued ASU No. 2015-16. This ASU eliminates the requirement to retrospectively apply measurement-period adjustments made to provisional amounts recognized in a business combination. The accounting update also requires an entity to present separately on the face of the income statement, or disclose in the notes, the portion of the amount recorded in current-period earnings, by line item, that would have been recorded in previous reporting periods if the adjustment to the estimated amounts had been recognized as of the acquisition date. ASU 2015-16 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. This standard should be applied prospectively, and early adoption is permitted. The Company elected for early adoption for its year end December 31, 2015 financial statements. The adoption of this standard did not have a significant impact on the Company’s financial statements.

In July 2015, the FASB issued ASU No. 2015-11, which updates the authoritative guidance for inventory, specifically that inventory should be valued at each reporting period at the lower of cost or net realizable value. This guidance is effective for the annual period beginning after December 15, 2016; early adoption is permitted. The Company is currently evaluating the impact of this new standard; however, the Company does not expect adoption to have a material impact on its financial statements.

In April 2015, the FASB issued ASU No. 2015-03, with an objective 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 liability rather than as an asset. Effective January 1, 2016, the Company adopted ASU No. 2015-03 on a retrospective basis. FASB ASU No. 2015-03 should be applied retrospectively and represent a change in accounting principle.

In August 2015, the FASB issued ASU No. 2015-15, which amends ASU 2015-03 which had not addressed the balance sheet presentation of debt issuance costs incurred in connection with line-of-credit arrangements. Under ASU 2015-15, a Company may defer debt issuance costs associated with line-of-credit arrangements and present such costs as an asset, 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. ASU 2015-15 is consistent with how the Company currently accounts for debt issuance costs related to the Company's credit facility.

In November 2014, the FASB issued ASU No. 2014-16, which updates authoritative guidance for derivatives and hedging instruments, specifically in determining whether the host contract in a hybrid financial instrument issued in the form of a share is more akin to debt or to equity. This guidance is effective for the annual period beginning after December 15, 2015; early adoption is permitted. The Company is currently evaluating the impact of this new standard; however, the Company does not expect adoption to have a material impact on its financial statements.

In August 2014, the FASB issued ASU No. 2014-15, with an objective to provide guidance on management's responsibility to evaluate whether there is substantial doubt about a company's ability to continue as a going concern and to provide related footnote disclosures. ASU 2014-15 is effective for fiscal years ending after December 15, 2016, and annual and interim periods thereafter. This standard is not expected to have an impact on the Company's financial statements.

In May 2014, the FASB issued ASU No. 2014-09, which establishes a comprehensive new revenue recognition model designed to depict the transfer of goods or services to a customer in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. The ASU allows for the use of either the full or modified retrospective transition method. In August 2015, the FASB issued ASU No. 2015-14, which deferred ASU No. 2014-09 for one year, and is effective for annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period. Earlier application is permitted only as of reporting periods beginning after December 15, 2016. The FASB subsequent issued ASU 2016-08, ASU 2016-10, ASU 2016-11 and ASU 2016-12, which provided additional implementation guidance. The Company is currently evaluating the level of effort necessary to implement the standards, evaluating the provisions of each of these standards, and assessing their potential impact on the Company's financial statements and disclosures, as well as determining whether to use the full retrospective method or the modified retrospective method.

There are no other accounting standards applicable to the Company that have been issued but not yet adopted by the Company as of September 30, 2016, and through the date the financial statements were available to be issued that would have a material impact on the Company's financial statements.

Note 3—Acquisitions

October 2016 Acquisition

On October 3, 2016, the Company acquired an unaffiliated oil and gas company's interests in approximately 6,100 net acres of leasehold, and related producing and non-producing properties located primarily in Weld County, Colorado, along with various other related rights, permits, contracts, equipment, rights of way, gathering systems and other assets (the "Bayswater Assets" and the acquisition, the "October 2016 Acquisition" or the "Bayswater Acquisition"). The seller received aggregate consideration of approximately $419.0 million in cash. The effective date for the acquisition was July 1, 2016, with purchase price adjustments calculated as of the closing date on October 3, 2016. The acquisition provides new development opportunities in the DJ Basin as well as increases the Company's existing working interest, as the majority of the locations are located on acreage in which the Company already owns a majority working interest and operates. The acquired producing properties contributed no revenue for the three and nine months ended September 30, 2016 and 2015, respectively. The Company incurred $0.3 million and $0.3 million of transaction costs related to the acquisition for the three and nine months ended September 30, 2016, respectively. These transaction costs are recorded in the consolidated statements of operations within the acquisition transaction expenses line item. The Company will also incur $2.0 million in transaction costs associated with a finder's fee to an unaffiliated third party. The fee was contingent on the transaction closing and will be expensed in the fourth quarter of 2016. No transaction costs related to the acquisition were incurred for the three and nine months ended September 30, 2015. The Company also made a $42.0 million deposit in July 2016 in conjunction with October 2016 Acquisition, which has been reflected in the September 30, 2016 consolidated balance sheet within the cash held in escrow line item.

The acquisition is accounted for using the acquisition method under ASC 805, *Business Combinations*, which requires the acquired assets and liabilities to be recorded at fair value as of the acquisition date of October 3, 2016. The Company has not completed the transaction's post-closing settlement, which is scheduled to occur in April 2017. As the post-close has not occurred, management has not had the opportunity to complete its assessment of the fair values of assets acquired and liabilities assumed. Accordingly, the below allocation will change as additional information becomes available and is assessed by the Company, and the impact of such changes may be material. The following table summarizes the preliminary purchase price and the preliminary estimated values of assets acquired and liabilities assumed (in thousands):

Preliminary Purchase Price		**October 3, 2016**
Consideration given		
Cash	$	419,044
Total consideration given	$	419,044
Preliminary Allocation of Purchase Price		
Proved oil and gas properties	$	255,105
Unproved oil and gas properties		109,900
Total fair value of oil and gas properties acquired		365,005
Goodwill	$	63,866
Working capital		(6,122)
Asset retirement obligations		(3,705)
Fair value of net assets acquired	$	419,044
Working capital acquired was estimated as follows:		
Revenue payable	$	(1,888)
Production taxes payable		(3,350)
Accrued liabilities		(884)
Total working capital	$	(6,122)

(1) Goodwill is estimated to be approximately $63.9 million based on the preliminary allocation of purchase price. Goodwill is primarily attributable to a decrease in commodity prices from the time the acquisition was negotiated and commodity prices on October 3, 2016 and the operational and financial synergies expected to be realized from the acquisition.

Option to Acquire Additional Assets from October 2016 Acquisition

Upon the closing of the October 2016 Acquisition, the Company made a $10.0 million non-refundable payment for an option to purchase additional assets from the seller of the October 2016 Acquisition (the "Additional Assets") for an additional $190.0 million, for a total purchase price for the Additional Assets of $200.0 million. The option may be exercised at any time until March 31, 2017. If the Company does not exercise the option to acquire the Additional Assets, the seller will have the right until April 30, 2017 to elect to sell those assets to the Company for an additional $120.0 million, for a total purchase price for the Additional Assets of $130.0 million. The Additional Assets include approximately 9,100 net acres of leasehold and related producing and non-producing properties located primarily in Weld County, and to a lesser extent Adams and Arapahoe Counties, Colorado, along with various other related rights, permits, contracts, equipment, rights of way, gathering systems and other assets. The Additional Assets would provide new development opportunities in the DJ Basin.

August 2016 Acquisition

On August 23, 2016, the Company acquired an unaffiliated oil and gas company's interests in approximately 850 net acres of leasehold located primarily in Weld County, Colorado, along with various other related rights, permits, contracts, equipment, rights of way and other assets (the "August 2016 Acquisition"). The seller received aggregate consideration of approximately $13.7 million in cash. The effective date for the acquisition was August 31, 2016, with purchase price adjustments calculated as of the closing date on August 23, 2016. The acquisition provided new development opportunities in the DJ Basin as well as additions adjacent to the Company's core project area. The acquired producing properties contributed de minimis revenue or earnings for the three and nine months ended September 30, 2016. The acquired producing properties contributed no revenue for the three and nine months ended September 30, 2015. The Company incurred $0.1 million and $0.1 million of transaction costs related to the acquisition for the three and nine months ended September 30, 2016, respectively. No transaction costs related to the acquisition were incurred for the three and nine months ended September 30, 2015. These transaction costs are recorded in the consolidated statements of operations within the acquisition transaction expenses line item.

The acquisition is accounted for using the acquisition method under ASC 805, Business Combinations, which requires the acquired assets and liabilities to be recorded at fair value as of the acquisition date of August 23, 2016. The Company has not completed the transaction's post-closing settlement, which is scheduled to occur in February 2017. As the post-close has not occurred, management has not had the opportunity to complete its assessment of the fair values of assets acquired and liabilities assumed. Accordingly, the below allocation will change as additional information becomes available and is assessed by the Company, and the impact of such changes may be material. The following table summarizes the preliminary purchase price and the preliminary estimated values of assets acquired and liabilities assumed (in thousands):

Preliminary Purchase Price	**August 23, 2016**
Consideration given	
Cash	$ 13,674
Total consideration given	$ 13,674
Preliminary Allocation of Purchase Price	
Proved oil and gas properties	$ 9,824
Unproved oil and gas properties	6,872
Total fair value of oil and gas properties acquired	16,696
Working capital	$ —
Asset retirement obligations	(3,022)
Fair value of net assets acquired	$ 13,674
Working capital acquired was estimated as follows (1):	
Accounts receivable	$ —
Revenue payable	—
Production taxes payable	—
Total working capital	$ —

(1)The Company anticipates acquiring various working capital items such as accounts receivable, revenue payable and production taxes payable liabilities. These working capital adjustments will result in an adjustment to the purchase price at closing. At this time, the working capital adjustments could not be estimated.

March 2015 Acquisition

On March 10, 2015, the Company acquired an unaffiliated oil and gas company's interests in approximately 39,000 net acres of leasehold, and related producing properties located primarily in Adams, Broomfield, Boulder and Weld Counties, Colorado, along with various other related rights, permits, contracts, equipment, rights of way, gathering systems and other assets (the "March 2015 Acquisition"). The seller received aggregate consideration of approximately $120.5 million in cash. The effective date for the acquisition was January 1, 2014, with purchase price adjustments calculated as of the closing date on March 10, 2015. The acquisition provided new development opportunities in the DJ Basin as well as additions adjacent to the Company's core project area and the acquired producing properties contributed revenue of $2.1 million and $6.8 million to the Company for the three and nine months ended September 30, 2016 respectively, and $2.8 million and $6.8 million to the Company for the three and nine months ended September 30 2015, respectively. The Company determined that it is not practical to calculate net income associated with March 2015 Acquisition. The Company incurred $0.5 million of transaction costs related to the acquisition for the nine months ended September 30, 2015. These transaction costs are recorded in the consolidated statements of operations within the general and administrative expense line item. No transaction costs related to the acquisition were incurred for the three months ended September 30, 2015. No transaction costs related to the acquisition were incurred for the three months ended September 30, 2016. Additionally, the Company incurred $6.0 million of non-cash transaction costs associated with a finder's fee to an unaffiliated third-party. The Company assigned an over-riding royalty interest in the proved and unproved oil and gas properties acquired in the March 2015 Acquisition, which had a fair value of $6.0 million on the measurement date. These transaction costs are recorded in the consolidated statements of operations within the acquisition transaction expense line item.

The acquisition is accounted for using the acquisition method under ASC 805, *Business Combinations*, which requires the acquired assets and liabilities to be recorded at fair value as of the acquisition date of March 10, 2015. In November 2015, the Company completed the transaction's post-closing settlement. The following table summarizes the purchase price and the final allocation of the fair values of assets acquired and liabilities assumed (in thousands):

Purchase Price		**March 10, 2015**
Consideration given		
Cash	$	120,524
Total consideration given	$	120,524
Allocation of Purchase Price		
Proved oil and gas properties	$	80,952
Unproved oil and gas properties		69,450
Total fair value of oil and gas properties acquired		150,402
Working capital	$	(1,996)
Asset retirement obligations		(27,882)
Fair value of net assets acquired	$	120,524
Working capital acquired was estimated as follows:		
Accounts receivable	$	462
Revenue payable		(718)
Production taxes payable		(1,740)
Total working capital	$	(1,996)

Pro Forma Financial Information

For the three and nine months ended September 30, 2016 and 2015, the following pro forma financial information represents the combined results for the Company and the properties acquired in the March 2015 Acquisition as if the acquisition and related financing had occurred on January 1, 2015. For purposes of the pro forma financial information, it was assumed that the Company issued equity to finance the March 2015 Acquisition. The pro forma financial information includes the effects of adjustments for depletion, depreciation, amortization and accretion expense of $1.5 million for the nine months ended September 30, 2015. The pro forma financial information includes the effects of a decrease in non-recurring transaction costs that are included in general and administrative expenses and acquisition transaction expenses of $6.4 million for the nine months ended September 30, 2015. The pro forma financial information excludes the effects of the October 2016 Acquisition as the information needed for the pro forma financial information was not available. Additionally, the pro forma financial information excludes the effects the August 2016 Acquisition as these pro forma adjustments were de minimis.

The following pro forma results (in thousands) do not include any cost savings or other synergies that may result from the acquisition or any estimated costs that have been or will be incurred by the Company to integrate the properties acquired. The pro forma results are not necessarily indicative of what actually would have occurred if the acquisition had been completed as of the beginning of the period, nor are they necessarily indicative of future results.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Revenues	$ 72,902	$ 48,846	$ 183,399	$ 143,624
Operating expenses	$ 95,214	$ 64,422	$ 273,581	$ 178,658
Net income (loss)	$ (37,267)	$ 18,650	$ (210,400)	$ (32,870)
Income (loss) per unit				
Basic	$ (0.11)	$ 0.07	$ (0.63)	$ (0.12)
Diluted	$ (0.11)	$ 0.07	$ (0.63)	$ (0.12)

Note 4—Long-Term Debt

As of the dates indicated the Company’s long-term debt consisted of the following (in thousands):

	September 30, 2016	December 31, 2015
Credit facility due November 29, 2018	$ 89,000	$ 225,000
Second Lien Notes due May 29, 2019	—	430,000
Senior Notes due July 15, 2021	550,000	—
Unamortized debt discount and debt issuance costs on Second Lien Notes and Senior Notes	(12,399)	(17,210)
Total long-term debt	626,601	637,790
Less: current portion of long-term debt	—	—
Total long-term debt, net of current portion	$ 626,601	$ 637,790

Credit Facility

On September 4, 2014, Holdings entered into a $500.0 million credit facility with a syndicate of banks, which is subject to a borrowing base. In connection with the IPO and the merger of Holdings into the Company, the Company assumed all of the obligations of Holdings under the credit facility and became the borrower thereunder. The credit facility matures on November 29, 2018. As of September 30, 2016, the credit facility was subject to a borrowing base of $350.0 million. As of September 30, 2016 and December 31, 2015, the Company had outstanding borrowings of $89.0 million and $225.0 million, respectively. As of September 30, 2016 and December 31, 2015, the Company had standby letters of credit of $0.6 million and $0.7 million, respectively. At September 30, 2016, the available credit under the credit facility was $260.4 million. As of the date of this filing, the Company has no balance outstanding under the credit facility.

Redetermination of the borrowing base occurred initially quarterly (on February 1, 2015, May 1, 2015, August 1, 2015, November 1, 2015 and February 1, 2016) and semiannually thereafter on May 1 and November 1. Additionally, the Company and the administrative agent under the credit facility may each elect a redetermination of the borrowing base between any two scheduled redeterminations, and the Company may elect a redetermination of the borrowing base on February 1, 2017 and August 1, 2017.

In September 2016, the Company elected an unscheduled borrowing base redetermination. As a result of this redetermination, the borrowing base increased to $350.0 million and would increase to $450.0 million upon the consummation of the October 2016 Acquisition. The October 2016 Acquisition was completed on October 3, 2016, increasing the borrowing base to $450.0 million.

Interest on the credit facility is payable at one of the following two variable rates as selected by the Company: a base rate based on the Prime Rate or the Eurodollar rate, based on LIBOR. Either rate is adjusted upward by an applicable margin, based on the utilization percentage of the facility as outlined in the Pricing Grid. Additionally, the credit facility provides for a commitment fee of 0.375% to 0.50%, depending on borrowing base usage. The grid below shows the Base Rate Margin and Eurodollar Margin depending on the applicable Borrowing Base Utilization Percentage (as defined in the credit facility) as of the date of this filing:

Borrowing Base Utilization Grid

Borrowing Base Utilization Percentage	Utilization	LIBOR Margin	Base Rate Margin	Commitment Fee
Level 1	< 25 %	2.00 %	1.00 %	0.375 %
Level 2	≥ 25% < 50 %	2.25 %	1.25 %	0.375 %
Level 3	≥ 50% < 75 %	2.50 %	1.50 %	0.500 %
Level 4	≥ 75% < 90 %	2.75 %	1.75 %	0.500 %
Level 5	≥ 90 %	3.00 %	2.00 %	0.500 %

The credit facility contains representations, warranties, covenants, conditions and defaults customary for transactions of this type, including but not limited to: (i) limitations on liens and incurrence of debt covenants; (ii) limitations on dividends, distributions, redemptions and restricted payments covenants; (iii) limitations on investments, loans and advances covenants; (iv) limitations on the sale of property, mergers, consolidations and other similar transactions covenants; and (v) holding cash balances in excess of certain thresholds while carrying a balance on the credit facility. Additionally, the credit facility limits the Company from hedging in excess of 85% of its anticipated production volumes.

The credit facility also contains financial covenants requiring the Company to comply with a current ratio of our consolidated current assets (includes unused commitments under our revolving credit facility and unrestricted cash and excludes derivative assets) to our consolidated current liabilities (excludes obligations under our revolving credit facility, the second lien notes and certain derivative assets), of not less than 1.0 to 1.0 and to maintain, on the last day of each quarter, a ratio of consolidated debt less cash balances in excess of certain thresholds to our consolidated EBITDAX (EBITDAX is defined as net income adjusted for certain cash and non-cash items including depreciation, depletion, amortization and accretion, exploration expense, gains/losses on derivative instruments, amortization of certain debt issuance costs, non-cash compensation expense, interest expense and prepayment premiums on extinguishment of debt) for the four fiscal quarter period most recently ended, of not greater than 4.0:1.0. For the quarters ending between December 31, 2016 through December 31, 2017, annualized EBITDAX will be based on the last six months' consolidated EBITDAX multiplied by 2, and for the quarter ending March 31, 2018, annualized EBITDAX will be based on the last nine months' consolidated EBITDAX multiplied by 4/3. For the quarters ending on or after June 30, 2018, annualized EBITDAX will be based on the last twelve months' consolidated EBITDAX. The Company was in compliance with all financial covenants under the credit facility as of September 30, 2016.

Any borrowings under the credit facility are collateralized by substantially all of the assets of the Company and its subsidiaries, including oil and gas properties, personal property and the equity interests of the subsidiaries of the Company. The Company has entered into oil and natural gas hedging transactions with several counterparties that are also lenders under the credit facility. The Company's obligations under these hedging contracts are secured by the collateral securing the credit facility.

Second Lien Notes

On May 29, 2014, Holdings entered in to a 5 year, $430.0 million term loan facility with a syndicate of lenders (the "Second Lien Notes"). The Second Lien Notes would have matured on May 29, 2019. Holdings had drawn the full $430.0 million under the Second Lien Notes and no further commitments remained. The loan was drawn in four tranches: $230.0 million in May 2014 that bore an interest rate of 11.0%, $75.0 million in July 2014 that bore an interest rate of 11.0%; $75.0 million in August 2014 that bore an interest rate of 10.0%, and $50.0 million in October 2014 that bore an interest rate of 10.0%. The interest rates were fixed and interest was payable semi-annually.

In July 2016, the Second Lien Notes were repaid and terminated in conjunction with the Senior Notes Offering. The Company used the proceeds from the Senior Notes (as discussed below) to repay the outstanding $430.0 million of principal and a $4.3 million prepayment penalty. The prepayment penalty was expensed in the third quarter of 2016 in the consolidated statements of operations within the interest expense line item. Additionally, in the third quarter of 2016, the Company wrote off approximately $15.1 million of unamortized debt discount and debt issuance costs that were related to the Second Lien Notes. The write off of the unamortized debt discount and debt issuance costs were recorded in the consolidated statements of operations within the interest expense line item.

Several lenders of Second Lien Notes were also members of Holdings. Of the $430.0 million formerly outstanding principal balance on the Second Lien Notes, members held approximately $311.7 million. These members were paid $314.8 million upon repayment and termination of the Second Lien Notes, including the prepayment penalty.

Senior Notes

In July 2016, the Company issued at par $550.0 million principal amount of 7.875% Senior Notes due July 15, 2021 (the “Senior Notes” and the offering, the Senior Notes Offering). The Senior Notes bear an annual interest rate of 7.875%. The interest on the Senior Notes is payable on January 15 and July 15 of each year commencing on January 15, 2017. The Company received net proceeds of approximately $537.5 million after deducting discounts and fees. All of the net proceeds from the Senior Notes were used to repay all of the outstanding borrowings and related premium, fees and expenses on the Second Lien Notes (which were terminated concurrently with such repayment), and the remaining proceeds were used to repay borrowings under the credit facility and for general business purposes.

Several lenders on the initial issuance of the Senior Notes were also members of Holdings. As of the date of the initial issuance of the $550.0 million principal amount on the Senior Notes, members held approximately $168.5 million.

The Senior Notes also contain affirmative and negative covenants that, among other things, limit the Company's and the Guarantors' ability to make investments; declare or pay any dividend or make any other payment to holders of the Company’s or any of its Guarantors’ equity interests; repurchase or redeem any equity interests of the Company; repurchase or redeem subordinated indebtedness; incur additional indebtedness or issue preferred stock; create liens; sell assets; enter into agreements that restrict dividends or other payments by restricted subsidiaries; consolidate, merge or transfer all or substantially all of the assets of the Company; engage in transactions with the Company's affiliates; engage in any business other than the oil and gas business; and create unrestricted subsidiaries. The Indenture also contains customary events of default. Upon the occurrence of events of default arising from certain events of bankruptcy or insolvency, the Senior Notes shall become due and payable immediately without any declaration or other act of the trustee or the holders of the Senior Notes. Upon the occurrence of certain other events of default, the trustee or the holders of at least 25% in aggregate principal amount of the then outstanding Senior Notes may declare all outstanding Senior Notes to be due and payable immediately. The Company was in compliance with all financial covenants under the Indenture as of September 30, 2016, and through the filing of this report.

Series A Preferred Units

On October 3, 2016, the Company issued $75.0 million in Series A Preferred Units (the “Series A Preferred Units”) to fund a portion of the purchase price for the October 2016 Acquisition. The Series A Preferred Units were entitled to receive a cash dividend of 10% per year, payable quarterly in arrears. All holders of Series A Preferred Units are also members of Holdings. The Company used $90.0 million of the net proceeds from its IPO to redeem the Series A Preferred Units in full on October 17, 2016, which included a premium of $15.0 million. For further discussion on the October 2016 Acquisition and IPO, please refer to *Note 3—Acquisitions* and *Note 8—Members’ Equity*, respectively.

Debt Discount Costs on Second Lien Notes

The Company’s Second Lien Notes were issued with an original issue discount (OID) of $6.5 million. In July 2016, the Company repaid the Second Lien Notes in full and accelerated the remaining unamortized balance of $4.3 million. This expense was recorded in the consolidated statements of operations within the interest expense line item. As of September 30, 2016, there was no remaining balance on the OID.

Debt Issuance Costs

As of September 30, 2016, the Company had debt issuance costs net of accumulated amortization of $1.8 million related to its credit facility which has been reflected on the Company's balance sheet within the line item other non-current assets. As of September 30, 2016, the Company had debt issuance costs of $12.4 million related to its Senior Notes which has been reflected on the Company's balance sheet within the line item Senior Notes, net of unamortized debt issuance costs. Upon the repayment of the Company's Second Lien Notes, the company accelerated the amortization of the remaining $10.8 million of unamortized debt issuance costs. This expense was recorded in the consolidated statement of operations within the interest expense line item. As of September 30, 2016, there was no remaining balance on debt issuance costs associated with the Second Lien Notes. Debt issuance costs include origination, legal, engineering, and other fees incurred in connection with the Company's credit facility, Second Lien Notes and Senior Notes. For the three and nine months ended September 30, 2016, the Company recorded amortization expense related to the debt issuance costs of $11.6 million and $13.5 million, respectively, as compared to $0.8 million and $2.3 million for the three and nine months ended September 30, 2015, respectively.

Interest Incurred On Long-Term Debt

For the three and nine months ended September 30, 2016, the Company incurred interest expense on long-term debt of $12.2 million and $38.9 million, respectively, as compared to $12.9 million and $37.4 million for the three and nine months ended September 30, 2015, respectively. For the three and nine months ended September 30, 2016, the Company capitalized interest expense on long term debt of $1.2 million and $3.6 million, respectively, as compared to $1.4 million and $4.1 million for the three and nine months ended September 30, 2015, respectively, which has been reflected in the Company's financial statements. Also included in interest expense for the three and nine months ended September 30, 2016 is a prepayment penalty of $4.3 million related to the Company's repayment of its Second Lien Notes in July 2016.

Note 5—Commodity Derivative Instruments

The Company has entered into commodity derivative instruments, as described below. The Company has utilized swaps, put options, and call options to reduce the effect of price changes on a portion of the Company's future oil and natural gas production.

A swap has an established fixed price. When the settlement price is below the fixed price, the counterparty pays the Company an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the fixed price, the Company pays its counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

A put option has an established floor price. The buyer of the put option pays the seller a premium to enter into the put option. When the settlement price is below the floor price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is above the floor price, the put option expires worthless. Some of the Company's purchased put options have deferred premiums. For the deferred premium puts, the Company agrees to pay a premium to the counterparty at the time of settlement.

A call option has an established ceiling price. The buyer of the call option pays the seller a premium to enter into the call option. When the settlement price is above the ceiling price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is below the ceiling price, the call option expires worthless.

The Company combines swaps, purchased put options, purchased call options, sold put options, and sold call options in order to achieve various hedging strategies. Some examples of the Company's hedging strategies are collars which include purchased put options and sold call options, three-way collars which include purchased put options, sold put options, and sold call options, and enhanced swaps, which include either sold put options or sold call options with the associated premiums rolled into an enhanced fixed price swap.

The objective of the Company's use of commodity derivative instruments is to achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage its exposure to commodity price risk. While the use of these commodity derivative instruments limits the downside risk of adverse price movements, such use may also limit the Company's ability to benefit from favorable price movements. The Company may, from time to time, add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of the Company's existing positions. The Company does not enter into derivative contracts for speculative purposes.

The use of derivatives involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. The Company's derivative contracts are currently with six counterparties. The Company has netting arrangements with the counterparties that provide for the offset of payables against receivables from separate derivative arrangements with the counterparties in the event of contract termination. The derivative contracts may be terminated by a non-defaulting party in the event of default by one of the parties to the agreement. There are no credit-risk-related contingent features or circumstances in which the features could be triggered in derivative instruments that are in a net liability position at the end of the reporting period.

The Company's commodity derivative contracts as of September 30, 2016 are summarized below:

	2016	2017	2018
NYMEX WTI(1) Crude Swaps:			
Notional volume (Bbl)	525,000	1,950,000	—
Weighted average fixed price ($/Bbl)	$ 38.70	$ 43.91	
NYMEX WTI(1) Crude Sold Calls:			
Notional volume (Bbl)	839,000	4,000,000	100,000
Weighted average fixed price ($/Bbl)	$ 55.15	$ 53.59	$ 55.00
NYMEX WTI(1) Crude Sold Puts:			
Notional volume (Bbl)	750,000	3,800,000	—
Weighted average fixed price ($/Bbl)	$ 45.00	36.41	
NYMEX WTI(1) Crude Purchased Puts:			
Notional volume (Bbl)	1,125,000	4,000,000	—
Weighted average purchased put price ($/Bbl)	$ 51.44	$ 46.15	
NYMEX HH(2) Natural Gas Swaps:			
Notional volume (MMBtu)	3,315,000	20,620,000	1,200,000
Weighted average fixed price ($/MMBtu)	$ 3.09	$ 3.02	$ 3.03
CIG(3) Basis Gas Swaps:			
Notional volume (MMBtu)	990,000	990,000	—
Weighted average fixed price ($/MMBtu)	$ (0.19)	$ (0.19)	

(1) NYMEX WTI refers to West Texas Intermediate crude oil price on the New York Mercantile Exchange

(2) NYMEX HH refers to the Henry Hub natural gas price on the New York Mercantile Exchange

(3)CIG refers to the NYMEX HH settlement price less the fixed basis price, the Rocky Mountains (CIGC) Inside FERC settlement price.

The following tables detail the fair value of the Company's derivative instruments, including the gross amounts and adjustments made to net the derivative instruments for the presentation in the balance sheets (in thousands):

	As of September 30, 2016				
Location on Balance Sheet	**Gross Amounts of Recognized Assets and Liabilities**	**Gross Amounts Offset in the Balance Sheet(1)**	**Net Amounts of Assets and Liabilities Presented in the Balance Sheet**	**Gross Amounts not Offset in the Balance Sheet(2)**	**Net Amounts(3)**
Current assets	$ 16,761	$ (16,229)	$ 532	$ (11)	$ 521
Non-current assets	$ 5,284	$ (5,284)	$ —	$ —	$ —
Current liabilities	$ (38,005)	$ 16,229	$ (21,776)	$ 11	$ (28,492)
Non-current liabilities	$ (12,011)	$ 5,284	$ (6,727)	$ —	$ —

	As of December 31, 2015				
Location on Balance Sheet	**Gross Amounts of Recognized Assets and Liabilities**	**Gross Amounts Offset in the Balance Sheet(1)**	**Net Amounts of Assets and Liabilities Presented in the Balance Sheet**	**Gross Amounts not Offset in the Balance Sheet(2)**	**Net Amounts(3)**
Current assets	$ 89,746	$ (20,861)	$ 68,885	$ —	$ 71,791
Non-current assets	$ 5,916	$ (3,010)	$ 2,906	$ —	$ —
Current liabilities	$ (20,861)	$ 20,861	$ —	$ —	$ —
Non-current liabilities	$ (3,010)	$ 3,010	$ —	$ —	$ —

(1) Agreements are in place with all of the Company's financial trading counterparties that allow for the financial right of offset for derivative assets and derivative liabilities at settlement or in the event of a default under the agreements.

(2) Netting for balance sheet presentation is performed by current and non-current classification. This adjustment represents amounts subject to an enforceable master netting arrangement, which are not netted on the balance sheet. There are no amounts of related financial collateral received or pledged.

(3) Net amounts are not split by current and non-current. All counterparties in a net asset position are shown in the current asset line item and all counterparties in a net liability position are shown in the current liability line item.

The table below sets forth the commodity derivatives gain (loss) for the three and nine months ended September 30, 2016 and 2015. Commodity derivatives gain (loss) are included under other income (expense).

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	**2015**	**2016**	**2015**
Commodity derivatives gain (loss)	$ 16,225	$ 46,886	$ (62,424)	$ 38,478

Note 6—Asset Retirement Obligations

The Company follows accounting for asset retirement obligations in accordance with ASC 410, *Asset Retirement and Environmental Obligations*, which requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it was incurred if a reasonable estimate of fair value could be made. The Company's asset retirement obligations primarily represent the estimated present value of the amounts expected to be incurred to plug, abandon and remediate producing and shut-in wells at the end of their productive lives in accordance with applicable state and federal laws. The Company determines the estimated fair value of its asset retirement obligations by calculating the present value of estimated cash flows related to plugging and abandonment liabilities. The significant inputs used to calculate such liabilities include estimates of costs to be incurred; the Company's credit adjusted discount rates, inflation rates and estimated dates of abandonment. The asset retirement liability is accreted to its present value each period and the capitalized asset retirement costs are depleted with proved oil and gas properties using the unit of production method.

The following table summarizes the activities of the Company's asset retirement obligations for the nine months ended September 30, 2016 and the year ended December 31, 2015 (in thousands):

	For the Nine Months Ended September 30, 2016	For the Year Ended December 31, 2015
Balance beginning of period	$ 44,367	$ 6,450
Liabilities incurred or acquired	4,037	35,624
Liabilities settled	(840)	(1,742)
Revisions in estimated cash flows	1,608	—
Accretion expense	4,062	4,035
Balance end of period	$ 53,234	$ 44,367

Note 7—Fair Value Measurements

ASC Topic 820, *Fair Value Measurement and Disclosure*, establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company's assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

- Level 1: Quoted prices are available in active markets for identical assets or liabilities;
- Level 2: Quoted prices in active markets for similar assets and liabilities that are observable for the asset or liability;
- Level 3: Unobservable pricing inputs that are generally less observable from objective sources, such as discounted cash flow models or valuations.

The financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. There were no transfers between levels during any periods presented below.

The following table presents the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2016 and December 31, 2015 by level within the fair value hierarchy (in thousands):

	Fair Value Measurements at September 30, 2016 Using			
	Level 1	Level 2	Level 3	Total
Financial Assets:				
Commodity derivative assets	$ —	$ 532	$ —	$ 532
Financial Liabilities:				
Commodity derivative liabilities	$ —	$ 28,503	$ —	$ 28,503

	Fair Value Measurements at December 31, 2015 Using			
	Level 1	Level 2	Level 3	Total
Financial Assets:				
Commodity derivative assets	$ —	$ 71,791	$ —	$ 71,791
Financial Liabilities:				
Commodity derivative liabilities	$ —	$ —	$ —	$ —

The following methods and assumptions were used to estimate the fair value of the assets and liabilities in the table above:

Commodity Derivative Instruments

The Company determines its estimate of the fair value of derivative instruments using a market based approach that takes into account several factors, including quoted market prices in active markets, implied market volatility factors, quotes from third parties, the credit rating of each counterparty, and the Company's own credit rating. In consideration of counterparty credit risk, the Company assessed the possibility of whether each counterparty to the derivative would default by failing to make any contractually required payments. Additionally, the Company considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions. Derivative instruments utilized by the Company consist of swaps, put options, and call options. The oil and natural gas derivative markets are highly active. Although the Company's derivative instruments are valued using public indices, the instruments themselves are traded with third-party counterparties and are not openly traded on an exchange. As such, the Company has classified these instruments as Level 2.

Fair Value of Financial Instruments

The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable, accounts payable, commodity derivative instruments (discussed above) and long-term debt. The carrying values of cash and cash equivalents, accounts receivable and accounts payable are representative of their fair values due to their short-term maturities. The carrying amount of the Company's credit facility approximated fair value as it bears interest at variable rates over the term of the loan. The fair value of the Second Lien Notes and Senior Notes was derived from available market data. As such, the Company has classified the Second Lien Notes and Senior Notes as Level 2. Please refer to *Note 4—Long-Term Debt* for further information. The Company's policy is to recognize transfers between levels at the end of the period. This disclosure (in thousands) does not impact the Company's financial position, results of operations or cash flows.

	At September 30, 2016		At December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Credit facility	$ 89,000	$ 89,000	$ 225,000	$ 225,000
Second Lien Notes(1)	$ —	$ —	$ 412,790	$ 433,196
Senior Notes(2)	$ 537,601	$ 573,375	$ —	$ —

(1)The carrying amount of the Second Lien Notes includes unamortized debt discount and debt issuance costs of $17.2 million as of December 31, 2015.
(2)The carrying amount of the Senior Notes includes unamortized debt issuance costs of $12.4 million as of September 30, 2016.

Non-Recurring Fair Value Measurements

The Company applies the provisions of the fair value measurement standard on a non-recurring basis to its non-financial assets and liabilities, including proved property. These assets and liabilities are not measured at fair value on a recurring basis, but are subject to fair value adjustments when facts are circumstances arise that indicate a need for measurement.

The Company utilizes fair value on a non-recurring basis to review its proved oil and gas properties for potential impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such property. The Company uses an income approach analysis based on the net discounted future cash-flows of producing property. The future cash-flows are based on Management's estimates for the future. Unobservable inputs included estimates of oil and gas production, as the case may be, from the Company's reserve reports, commodity prices based on the sales contract terms or forward price curves, operating and development costs, and a discount rate based on the Company's weighted average cost of capital (all of which are Level 3 inputs within the fair value hierarchy). No impairment expense was recognized for the three months ended September 30, 2016 on proved oil and gas properties. For the nine months ended September 30, 2016, the Company recognized $22.5 million in impairment expense on proved oil and gas properties. No impairment expense was recognized for the three months ended September 30, 2015 on proved oil and gas properties. For the nine months ended September 30, 2015, the Company recognized $9.5 million in impairment expense on proved oil and gas properties. The impairment expense for the nine months ended September 30, 2016 and 2015 is related to impairment of the assets in the Company's Northern field. The future undiscounted cash flows did not exceed its carrying amount associated with its proved oil and gas properties in its Northern field and it was determined that the proved oil and gas properties had no remaining fair value. Therefore, the full net book value of these proved oil and gas properties were impaired at June 30, 2016 and 2015, respectively.

The Company's other non-recurring fair value measurements include the purchase price allocations for the fair value of assets and liabilities acquired through business combinations, please refer to *Note 3—Acquisitions*. The fair value of assets and liabilities acquired through business combinations is calculated using a discounted-cash flow approach using level 3 inputs. Cash flow estimates require forecasts and assumptions for many years into the future for a variety of factors, including risk-adjusted oil and gas reserves, commodity prices and operating costs, based on market participant assumptions. The fair value of assets or liabilities associated with purchase price allocations is on a non-recurring basis and is not measured in periods after initial recognition.

Note 8—Members' Equity

Tranche A, Tranche B and Preferred Tranche C Unit Issuance

At September 30, 2016, the Company's operations were governed by the provisions of the Amended and Restated Limited Liability Company Agreement effective March 10, 2015 ("Holdings LLC Agreement") and the Company had two classes of voting membership interests outstanding, the Tranche A Equity Units and the Tranche C Equity Units. In connection with the Reorganization, on May 29, 2014, the following Tranche A Equity Units were issued:

- 62.4 million Tranche A Equity Units were issued to certain members that had made historical capital contributions to Extraction through PRL at a price of $1.02 per unit for gross proceeds of $63.4 million; and,

- 14.5 million Tranche A Equity Units were issued to certain members to settle $39.0 million of Extraction convertible notes at a price of $2.68 per unit for gross proceeds of $39.0 million.

Additionally, on May 29, 2014, 75.6 million Tranche A Equity Units were issued to new and existing members in exchange for additional capital contributions at a price of $2.68 per unit for gross proceeds of $202.9 million.

On August 20, 2014, the Company issued an additional 74.5 million Tranche A Equity Units to new and existing members in exchange for additional capital contributions at a price of $2.68 per unit for gross proceeds of $199.9 million.

On February 18, 2015, the Company issued 15.3 million Tranche B Equity Units to certain Members at a purchase price of $3.25 per unit for gross proceeds of $49.5 million. The Tranche B Equity Unit holders were granted certain rights in Holdings' LLC Agreement. Included was a right to exchange the Tranche B Equity Units for new equity units at a price of $3.25 per unit if the Company issues any equity units with rights, preferences or obligations different from the Tranche B Units on or prior to May 14, 2015.

On March 10, 2015, the Company issued 32.5 million Tranche C Equity Units to certain new and existing Members at a purchase price of $3.25 per unit for gross proceeds of $105.7 million and each Tranche B Equity Unit was reclassified as a Tranche C Equity Unit, such that no Tranche B Equity Units remain outstanding. The Tranche C Equity Unit holders were granted certain rights in Holdings' LLC Agreement. Included with these rights were, (1) the right to receive their invested capital prior to any distribution to any other unit holders, (2) the right to receive additional Tranche C units under specified circumstances contingent upon an initial public offering or certain change of control events and (3) the right to approve the issue of equity units with any rights or preferences that are senior to the rights and preferences of the Tranche C Equity Units.

On September 24, 2015, the Company issued 22.9 million Tranche C Equity Units to Members at a purchase price of $3.25 per unit for gross proceeds of $74.3 million.

On October 13, 2015, the Company issued 7.9 million Tranche C Equity Units to new and existing Members at a purchase price of $3.25 per unit for gross proceeds of $25.7 million.

In April 2016 and June 2016, the Company issued 35.8 million Preferred Tranche C Equity Units to new and existing Members at a purchase price of $3.25 per unit for gross proceeds of $116.4 million. The proceeds of the April and June 2016 Offering were used for general business purposes, including to repay amounts borrowed under the Company’s credit facility.

In July 2016, the Company issued an additional 1.5 million Preferred Tranche C Equity Units to new and existing Members at a purchase price of $3.25 per unit for gross proceeds of $5.0 million. The proceeds of the July 2016 Offering were used for general business purposes, including to repay amounts borrowed under the Company’s credit facility.

The Company incurred equity issuance costs related to the aforementioned equity offerings of $15.5 million from inception through September 30, 2016. These equity issuance costs were recorded as a reduction to Members’ Equity.

Restricted Unit Awards (“RUAs”)

Under the Holdings LLC Agreement, the Company could grant RUAs to employees, non-employee managers and consultants. RUAs are nonvoting membership interests in the Company and are subject to certain vesting and forfeiture conditions, but have equal rights and preferences to the Tranche A Equity Units in all other regards. See *Note 9—Unit-Based Compensation* for additional information.

Promissory Notes

In May 2014, the Company received full recourse promissory notes from two officers under which the Company advanced $5.4 million to the employees to meet their capital contributions. The promissory notes were due on May 29, 2021, or earlier in the event of termination or certain change in control events as stipulated in the individual promissory notes and any distributions of capital contributions are considered mandatory prepayments. The promissory notes have a stated interest rate of LIBOR plus 1% per annum. The promissory notes are recorded as a reduction of members’ equity.

In September 2016, the Company redeemed 1.2 million units from two of its executive officers, for an aggregate purchase price of $7.8 million. On the same date, the executive officers used $5.6 million of the redemption value to settle in full and terminate their obligations under the promissory notes, including accrued interest thereon.

Initial Public Offering

In October 2016, the Company completed its initial public offering, issuing 38.3 million shares of common stock, par value $0.01 per share (“common stock”), which includes the full exercise of the underwriters over-allotment option of 5.0 million shares at a price of $19.00 per share. The estimated net proceeds of the offering were $683.7 million, after deducting underwriting discounts and commissions and offering expenses, of approximately $44.4 million. The proceeds from the Offering were used to (i) redeem in full the Series A Preferred Units for $90.0 million and (ii) to repay borrowings under the Company’s revolving credit facility for $291.6 million. The remaining net proceeds will be used for general corporate purposes, including to fund the 2016 and 2017 capital expenditures. The material terms of the Offering are described in the Company’s final prospectus, dated October 11, 2016 and filed with the SEC pursuant to Rule 424(b)(4) of the Securities Act of 1933, as amended, on October 13, 2016 (the “Final Prospectus”).

At the consummation of the IPO, Holdings merged with and into XOG and XOG was the surviving entity to the merger, with the equity holders in Holdings, other than the holders of the Series B Preferred Units (which were converted in connection with the closing of the Offering into shares of Series A Preferred Stock as defined below), but including the holders of RUAs and incentive units, receiving an aggregate of 108.5 million shares of common stock, with the allocation of such shares among Holdings’ equity holders determined by reference to the Company’s implied valuation based on the 10-day volume weighted average price of the common stock following the closing of the Offering, in accordance with the distribution mechanics set forth in the Holdings LLC Agreement. As a result of the Offering, there are 146.8 million common shares outstanding as of the date of this filing.

Series A Preferred Stock and Series B Preferred Units

On October 3, 2016, the Company issued $185.3 million in convertible preferred securities ("Series B Preferred Units") to fund a portion of the purchase price for the October 2016 Acquisition. The Series B Preferred Units were entitled to receive a cash dividend of 10% per year, payable quarterly in arrears, and the Company had the ability to pay up to 50% of the quarterly dividend in kind. The Company did not make any payments in kind on the Series B Preferred Units from the date of issuance of the Series B Preferred Units through the Offering. The Series B Preferred Units converted in connection with the closing of the IPO into 185,280 shares of Series A Convertible Preferred Stock (the "Series A Preferred Stock") that are entitled to receive a cash dividend of 5.875% per year, payable quarterly in arrears, and the Company has the ability to pay such quarterly dividends in kind at a dividend rate of 10% per year (decreased proportionately to the extent such quarterly dividends are paid in cash). Beginning on or after the later of (a) 90 days after the closing of the Offering and (b) the earlier of 120 days after the closing of the Offering and the expiration of the lock-up period contained in the underwriting agreement entered into in connection with the Offering ("Lock-Up Period End Date"), the Series A Preferred Stock will be convertible into shares of our common stock at the election of the holders of the Series A Preferred Stock ("Series A Preferred Holders") at a conversion ratio per share of Series A Preferred Stock of 61.9195. Beginning on or after the Lock-Up Period End Date until the three year anniversary of the closing of the Offering, the Company may elect to convert the Series A Preferred Stock at a conversion ratio per share of Series A Preferred Stock of 61.9195, but only if the closing price of the Company’s common stock trades at or above a certain premium to the Company’s initial offering price, such premium to decrease with time. In certain situations, including a change of control, the Series A Preferred Stock may be redeemed for cash in an amount equal to the greater of (i) 135% of the liquidation preference of the Series A Preferred Stock and (ii) a 17.5% annualized internal rate of return on the liquidation preference of the Series A Preferred Stock. The Series A Preferred Stock mature on October 15, 2021, at which time they are mandatorily redeemable for cash at the liquidation preference. As of the initial issuance of the $185.3 million of Series B Preferred Units, members of Holdings held approximately $135.3 million. Upon closing of the Offering, members of Holdings held $185.3 million of the Series A Preferred Stock.

Note 9—Unit-Based Compensation

Holdings’ RUAs

On May 29, 2014, the Company adopted the 2014 Membership Unit Incentive Plan (“2014 Plan”). The 2014 Plan provided for the compensation of employees, non-employee managers and consultants of the Company and its affiliates through grants of restricted unit awards (“Holdings’ RUAs”) and incentive units (“Holdings’ Incentive Units”). As of September 30, 2016, no Holdings’ RUAs remained available for issuance under the 2014 Plan.

At the Reorganization through September 30, 2016, the following Holdings' RUA activity occurred related to the Company's employees and non-employee consultants:

- 3.4 million Holdings' RUAs were granted to each holder of PRL RUAs as part of the Reorganization, (as defined below under the heading "PRL RUAs");
- 3.5 million Holdings' RUAs were granted to certain Company employees and consultants to keep their equity ownership whole as part of the Reorganization;
- 1.4 million Holdings' RUAs were granted to certain members of Extraction management who participated in Extraction's Net Profits Interest Bonus Plan, which was terminated on May 29, 2014 as part of the Reorganization;
- 1.9 million Holdings' RUAs were granted to certain Company employees that were hired subsequent to the Reorganization; and
- 1.5 million Holdings' RUAs were granted to certain officers.

Holdings' RUAs vested over a three-year service period, with 25%, 25% and 50% of the units vesting in year one, two and three, respectively. The vesting period for the 3.4 million Holdings' RUAs granted to holders of PRL RUAs was carried over from the original PRE RUA grants; as such, 0.2 million Holdings' RUAs were vested on May 29, 2014. The vesting period for all other Holdings' RUAs begins on the grant date. During September 2016, vesting was accelerated on all of the Holdings' RUAs, as such, as of September 30, 2016, all Holdings' RUAs were fully vested. The Company estimated fair value of the RUAs on their grant date based upon estimated volatility, market comparable risk free rate, estimated forfeiture rate and a discount for lack of marketability. Grant date fair value was determined based on the value of the Company's Equity Units on the date of the grant. Due to a lack of historical data, the Company used the experience of other entities in the same industry to estimate a forfeiture rate. Expected forfeitures are then included as part of the grant date estimate of compensation cost.

The Company recorded $12.2 million and $14.5 million of unit-based compensation costs related to Holdings' RUA grants for the three and nine months ended September 30, 2016 , respectively, as compared to $1.3 million and $4.1 million for the three and nine months ended September 30, 2015, respectively. These costs are included in the consolidated statements of operations within the general and administrative expenses line item. No tax benefit related to unit-based compensation was recognized in the consolidated statements of operations and no unit-based compensation was capitalized for the three and nine months ended September 30, 2016 and 2015. As of September 30, 2016, there was no unrecognized compensation cost related to unvested Holdings' RUAs granted to employees as all Holdings' RUAs were fully vested at September 30, 2016.

Of the 3.4 million Holdings' RUAs granted to holders of PRL RUAs in connection with the Reorganization, 1.3 were granted to PRL employees or consultants. The Company does not record any unit-based compensation expense related to these awards because PRL employees or consultants do not provide services to the Company.

Of the 3.5 million Holdings' RUAs granted to certain employees and consultants to keep their equity ownership whole as part of the Reorganization, 1.3 were granted to PRL employees or consultants. The Company does not record any unit-based compensation expense related to these awards because PRL employees or consultants do not provide services to the Company.

The following table summarizes the Holdings' RUA activity from the January 1, 2015 through September 30, 2016 and provides information for Holdings' RUAs outstanding at the dates indicated:

	Number of Shares	Weighted Average Grant Date Fair Value
Non-vested RUAs at January 1, 2015	9,365,896	$ 2.22
Granted	196,047	$ 2.68
Forfeited	(53,063)	$ 2.21
Vested	(3,197,638)	$ 2.22
Non-vested RUAs at December 31, 2015	6,311,242	$ 2.23
Granted	1,531,542	$ 5.84
Forfeited	(181,817)	$ 2.68
Vested	(7,660,967)	$ 2.94
Non-vested RUAs at September 30, 2016	—	$ —

PRL RUAs

Prior to the Reorganization, PRL granted RUAs to certain employees, including Extraction employees ("PRL RUAs"). Subsequent to the Reorganization, Extraction's employees retained the PRL RUAs. PRL RUAs vest over a three year service period, with 25%, 25% and 50% of the units vesting in year one, two and three, respectively. Grant date fair value was determined based on the value of PRL's Equity Units on the date of the grant. PRL uses its past experience to estimate a forfeiture rate and expected forfeitures are included as part of the grant date estimate of compensation cost.

The Company recorded $0.1 million and $0.4 million of unit- based compensation costs related to PRL RUA grants for the three and nine months ended September 30, 2016, respectively, as compared to $0.2 million and $0.6 million for the three and nine months ended September 30, 2015, respectively. These costs are included in the consolidated statements of operations within the general and administrative expenses line item. As of September 30, 2016, there was $0.1 million of total unrecognized compensation cost related to unvested PRL RUAs granted to employees that is expected to be recognized over a weighted-average period of 0.2 years.

Holdings' Incentive Units

In accordance with the 2014 Plan and the Holdings LLC Agreement, Holdings issued incentive units to certain members of management in the fourth quarter of 2015. As of September 30, 2016, 3.0 million Holdings' Incentive Units have been issued. No Holdings' Incentive Units were issued during 2016. All of Holdings' Incentive Units are non-voting and subject to certain vesting and performance conditions. The Holdings' Incentive Units vested over a three year service period, with 25%, 25% and 50% of the units vesting in year 1, year 2 and year 3, respectively (with vesting between the first and third anniversaries occurring pro-rata based on the number of full months elapsed since the last vesting date), and in full upon a change of control, as defined in the Holdings LLC Agreement. The Holdings' Incentive Units are accounted for as liability awards under ASC 718, *Compensation—Stock Compensation*, with compensation expense based on period-end fair value. No incentive compensation expense was recorded for the three and nine months ended September 30, 2016 and 2015, because it was not probable that the performance criterion would be met.

In anticipation of the IPO, the Board of Managers of Holdings accelerated the vesting of the Holdings' Incentive Units in September 2016. During the fourth quarter of 2016, the Company's IPO and change of control triggered the conversion of these units into approximately 9.1 million common shares of the Company based on the 10-day volume weighted average price of the Company's commons stock following its IPO as set forth in the 2014 Plan and the Holdings LLC Agreement. The Company will recognize approximately $172.1 million in non-cash, share-based compensation expense in the fourth quarter of 2016 in connection with the conversion of the Holdings' Incentive Units into the Company's common stock.

Long Term Incentive Plan

In October 2016, the Board of Managers adopted the Extraction Oil & Gas, Inc. 2016 Long Term Incentive Plan (the “2016 Plan” or “LTIP”), pursuant to which employees, consultants, and directors of the Company and its affiliates performing services for the Company are eligible to receive awards. The 2016 Plan provides for the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, bonus stock, dividend equivalents, other stock-based awards, substitute awards, annual incentive awards, and performance awards intended to align the interests of participants with those of stockholders. In accordance with the terms of the LTIP, 20.2 million shares of common stock have been reserved for issuance pursuant to awards under the LTIP. In October 2016, and in connection with our Offering, XOG granted awards under the LTIP to certain directors and officers.

Note 10—Earnings (Loss) Per Unit

As discussed in *Note 8—Members' Equity*, the Company had Tranche A and Tranche C Equity Units. Additionally, the Company's RUAs are classified as Tranche A non-voting units upon vesting. In a distribution of capital in excess of contributed capital, the Company's two types of Equity Units, Tranche A and Tranche C, participated in distributions proportionally based on their respective share of the total number of equity units outstanding. The Tranche C Equity Units received their contributed capital prior to Tranche A only in a liquidation event. The Company assumed liquidation in excess of capital contributions, thus the Tranche C and A Units are considered in the same class for the purpose of computing earnings (loss) per unit. In connection with the IPO, the equity holders in Holdings, other than the holders of the Series B Preferred Units, but including the holders of RUAs and incentive units, received common stock in XOG.

Basic earnings (loss) per unit is computed by dividing income (loss) attributable to unitholders by the weighted average number of units outstanding during each period. Diluted earnings per unit reflects the potential dilutive impact from unvested RUAs. As of September 30, 2016, there were no remaining unvested RUAs available for grant under the 2014 Plan. As of September 30, 2015, there were 7.0 million unvested RUAs. In periods of net loss, as was the case for the three and nine months ended September 30, 2016 and 2015 and the three months ended September 30, 2016, potentially dilutive units are excluded from the calculation because they are anti-dilutive.

The table below sets forth the computations of basic and diluted net income (loss) per unit for the three and nine months ended September 30, 2016 and 2015 (in thousands, except per unit data):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Net income (loss) allocable to Equity Units	$ (37,267)	$ 18,650	$ (210,400)	$ (38,060)
Weighted-average shares:				
Weighted average Equity Units outstanding - basic	349,014	279,896	332,377	266,844
Weighted average Equity Units outstanding - diluted	349,014	286,891	332,377	266,844
Income (loss) per Equity Unit(1):				
Basic	$ (0.11)	$ 0.07	$ (0.63)	$ (0.14)
Diluted	$ (0.11)	$ 0.07	$ (0.63)	$ (0.14)

(1)For the nine months ended September 30, 2016 and 2015 and the three months ended September 30, 2016, the anti-dilutive RUAs were excluded from the if-converted method of calculating diluted earnings per unit. For the three months ended September 30, 2015, 7.0 million unvested RUAs were included in the if-converted method of calculating diluted earnings per unit.

Note 11—Commitments and Contingencies

Leases

The Company leases two office spaces in Denver, Colorado, one office space in Greeley, Colorado and one office space in Houston, Texas under separate operating lease agreements. The Denver, Colorado leases expire on February 29, 2020 and May 31, 2026, respectively. The Greeley and Houston leases expire on March 31, 2019 and October 31, 2017, respectively. Total rental commitments under non-cancelable leases for office space were $21.6 million at September 30, 2016. The future minimum lease payments under these non-cancelable leases are as follows: $0.6 million in 2016, $2.5 million in 2017, $2.5 million in 2018, $2.3 million in 2019, $2.1 million in 2020 and $11.6 million thereafter. Rent expense was $0.6 million and $1.3 million for the three and nine months ended September 30, 2016, respectively, as compared to $0.3 million and $0.7 million for the three and nine months ended September 30, 2015, respectively.

On June 4, 2015 and March 22, 2016, the Company subleased the remaining term of one of its Denver office leases that expires February 29, 2020. As of September 30, 2016, the sublease will decrease the Company's future lease payments by $0.8 million.

Drilling Rigs

As of September 30, 2016, the Company had commitments on two drilling rigs. In the event of early termination, the Company would be obligated to pay approximately $1.9 million as of September 30, 2016, as required under the terms of the contract. In March 2015, the Company early terminated one of its drilling rig contracts for approximately $1.7 million, which was recorded in the consolidated statements of operations within the other operating expenses line item. In February 2016, the Company provided notice to terminate one of its drilling rigs for approximately $0.9 million that was subject to commitment at December 31, 2015. This amount was recorded in the consolidated statements of operations within the other operating expenses line item.

Delivery Commitments

As of September 30, 2016, the Company was subject to a long-term crude oil delivery commitment over a term of 10 years with a commencement date of November 30, 2016. The terms have a fixed monthly delivery commitment of 40,000 Bpd in year one, 52,000 Bpd in year two, and 58,000 Bpd in years three through ten at a price of $3.95 per barrel which is subject to standard Federal Energy Regulatory Commission ("FERC") escalation rates. The aggregate amount of estimated payments under the agreement is $887.3 million over the ten years.

Upon closing the October 2016 Acquisition, the Company is subject to two additional long-term crude oil delivery commitments. The first has a term of seven years with a commencement date of November 1, 2016, which has delivery commitment obligations of 5,000 Bpd in year one and 3,800 Bpd in year two through seven. The aggregate amount of estimated payments under the agreement is $55.2 million over the seven years. The second has a term of five years with a commencement date of November 1, 2016, which has delivery commitments obligations of 5,000 Bpd in year one and 3,800 Bpd in year two through five. The aggregate amount of the estimate payments under the agreement is $10.4 million over the five years.

None of the Company's reserves are subject to any priorities or curtailments that may affect quantities delivered to its customers. The Company believes that its future production is adequate to meet its commitments. If for some reason the Company's production is not sufficient to satisfy its commitments, the Company expects to be able to purchase volumes in the market or make other arrangements to satisfy its commitments.

General

The Company is subject to contingent liabilities with respect to existing or potential claims, lawsuits, and other proceedings, including those involving environmental, tax, and other matters, certain of which are discussed more specifically below. The Company accrues liabilities when it is probable that future costs will be incurred and such costs can be reasonably estimated. Such accruals are based on developments to date and the Company's estimates of the outcomes of these matters and its experience in contesting, litigating, and settling other matters. As the scope of the liabilities becomes better defined, there will be changes in the estimates of future costs, which management currently believes will not have a material effect on the Company's financial position, results of operations, or cash flows.

As is customary in the oil and gas industry, the Company may at times have commitments in place to reserve or earn certain acreage positions or wells. If the Company does not meet such commitments, the acreage positions or wells may be lost or the Company may be required to pay damages if certain performance conditions are not met.

Legal Matters

In the first three quarters of 2016, the Company received nine invoices related to a terminated firm natural gas transportation service agreement. The natural gas transportation provider has demanded payment under this terminated agreement. The Company has delivered written notice disputing any and all amounts due related to this terminated agreement. The Company intends to vigorously defend itself against any and all demands, if legal proceedings relating to this matter are initiated; we may incur material legal expenses if this dispute results in litigation. The Company is unable to estimate a reasonable possible loss. In the event there is an adverse outcome, the Company currently estimates that its future loss would range between $0 million to $37.2 million that would be paid over the remainder of the original 10 year term of transportation service agreement.

In the ordinary course of business, the Company may at times be subject to claims and legal actions. Management believes it is remote that the impact of such matters will have a material adverse effect on the Company's financial position, results of operations or cash flows. Management is unaware of any pending litigation brought against the Company requiring the reserve of a contingent liability as of the date of these financial statements.

Note 12—Related Party Transactions

Office Lease with Related Affiliate

In March 2016, the Company subleased office space to Star Peak Capital, LLC, of which a member of the board of managers is an owner, for $1,400 per month. The sublease commenced on May 1, 2016 and expires on February 29, 2020.

Units Repurchased from Officer

In May 2016, the Company repurchased 60,605 Tranche A Units and 82,578 Tranche C Units from its former Chief Accounting Officer, for $3.25 per unit for an aggregate purchase price of approximately $0.5 million.

Promissory Notes

In May 2014, the Company received full recourse promissory notes from two officers under which the Company advanced $5.4 million to the employees to meet their capital contributions. The promissory notes are due on May 29, 2021, or earlier in the event of termination or certain change in control events as stipulated in the individual promissory notes and any distributions of capital contributions are considered mandatory prepayments. The promissory notes have a stated interest rate of LIBOR plus 1% per annum. The promissory notes are recorded as a reduction of members' equity.

In September 2016, the Company redeemed 1,195,472 units from two of its executive officers, with an aggregate value of $7.8 million. On the same date, the executive officers used $5.6 million of the redemption value to settle in full and terminate their obligations under the promissory notes, including interest thereon.

Second Lien Notes

Several lenders of Second Lien Notes were also members of Holdings. Of the $430.0 million formerly outstanding on the Second Lien Notes, members held approximately $311.7 million. These members were paid $314.8 million upon repayment and termination of the Second Lien Notes, including the prepayment penalty.

Senior Notes

Several lenders of Senior Notes are also members of Holdings. As of the initial issuance of the $550.0 million principal amount on the Senior Notes, members held approximately $168.5 million.

Series A Preferred Units

All holders of the $75.0 million of Series A Preferred Units as of September 30, 2016 were also members of Holdings. The Company used $90.0 million of the net proceeds from its IPO to redeem the Series A Preferred Units in full on October 17, 2016, which included a premium of $15.0 million.

Series A Preferred Stock and Series B Preferred Units

As of the initial issuance of the $185.3 million of Series B Preferred Units, members of Holdings held approximately $135.3 million. Upon closing of the IPO, members of Holdings held $185.3 million of the Series A Preferred Stock.

Due to Related Party

As of December 31, 2014, the Company had recorded a payable due to related party of $0.2 million with PRL for certain general and administrative expenses, which included salary and related benefits, office rent, insurance premiums and other general and administrative costs, which was repaid in April 2015.

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

The following discussion and analysis should be read in conjunction with the condensed financial statements and related notes included elsewhere in this report.

EXECUTIVE SUMMARY

We are an independent oil and gas company focused on the acquisition, development and production of crude oil, natural gas and NGL reserves in the Rocky Mountain region of the United States, primarily in the Wattenberg Field of the DJ Basin of Colorado. We have developed an oil, natural gas and NGL asset base of proved reserves, as well as a portfolio of development drilling opportunities on high resource-potential leasehold on contiguous acreage blocks in the Wattenberg Field. We are focused on growing our proved reserves and production primarily through the development of our large inventory of identified liquids-rich horizontal drilling locations.

Financial Overview

For the three and nine months ended September 30, 2016, crude oil, natural gas and NGL sales, coupled with the impact of settled derivatives, increased to $77.6 million and $215.9 million as compared to $63.0 million and $183.0 million in the same prior year periods due to an increase in sales volumes of 820.7 MBoe and 2,575.6 MBoe, respectively, offset primarily by declines of $5.06 and $8.65, respectively, in realized price per barrel of crude oil equivalent ("BOE"), including settled derivatives.

For the three and nine months ended September 30, 2016, we had a net loss of $37.3 million and $210.4 million, respectively, as compared to net income of $18.7 million for the three months ended September 30, 2015 and a net loss of $38.1 million for the nine months ended September 30, 2015.

Adjusted EBITDAX was $48.2 million and $138.0 million, respectively for the three and nine months ended September 30, 2016, as compared to $42.9 million and $129.9 million in the same periods in 2015, reflecting a 12% and 6% increase, respectively. Adjusted EBITDAX is a non-GAAP financial measure. For a definition of Adjusted EBITDAX and a reconciliation to our most directly comparable financial measure calculated and presented in accordance with GAAP, please read "—Adjusted EBITDAX."

Operational Overview

During the nine months ended September 30, 2016, we continued to focus on growing production while at the same time implementing operational efficiencies to reduce drilling and completion costs. We drilled 69 gross (60 net) horizontal wells and completed 55 gross (44 net) horizontal wells in the Wattenberg Field. As of October 2016, we are running a continuous two rig drilling program.

Recent Developments

October 2016 Acquisition

On July 29, 2016, we entered into a definitive agreement with subsidiaries of Bayswater Exploration & Production to acquire additional oil and gas properties primarily located in the Wattenberg Field for total consideration of $419.0 million in cash, subject to customary purchase price adjustments. The Bayswater Acquisition consist of working interests in approximately 6,100 net acres, and had a net daily production of approximately 9,000 net BOE/d during the month ended August 31, 2016. As of September 30, 2016, the Bayswater Acquisition included 31 gross (19 net) drilled but uncompleted wells. We expect the majority of these drilled but uncompleted wells to be brought online in the first half of 2017. We closed the Bayswater Acquisition on October 3, 2016.

Option to Acquire Additional Assets from October 2016 Acquisition

Upon the closing of the October 2016 Acquisition, we made a $10.0 million non-refundable payment for an option to purchase additional assets from the seller of the October 2016 Acquisition for an additional $190.0 million, for a total purchase price for the Additional Assets of $200.0 million. The option may be exercised at any time until March 31, 2017. If we do not exercise the option to acquire the Additional Assets, the seller will have the right until April 30, 2017 to elect to sell those assets to the Company for an additional $120.0 million, for a total purchase price for the Additional Assets of $130.0 million. The Additional Assets include approximately 9,100 net acres of leasehold and related producing and non-producing properties located primarily in Weld County, and to a lesser extent Adams and Arapahoe Counties, Colorado, along with various other related rights, permits, contracts, equipment, rights of way, gathering systems and other assets. The Additional Assets would provide new development opportunities in the DJ Basin.

Initial Public Offering

On October 17, 2016, we completed an initial public offering of 33.3 million shares of our common stock at a price to the public of $19.00 per share and we became a publicly traded company listed on NASDAQ under the ticker symbol "XOG". After deducting underwriting discounts and commissions and estimated offering expenses payable by us, we received approximately $683.7 million of aggregate net proceeds from our IPO, after the underwriters exercised their option on October 24, 2016 to purchase 5.0 million additional shares in full. We used (i) $90.0 million of the net proceeds from the Offering to redeem in full the Series A Preferred Units and (ii) $291.6 million to repay borrowings under our revolving credit facility. We intend to use the remaining net proceeds for general corporate purposes, including to fund our 2016 and 2017 capital expenditures.

Senior Notes and the Redemption of Second Lien Notes

In July 2016, we closed a private offering of our unsecured 7.875% Senior Notes due 2021 that resulted in net proceeds of approximately $537.5 million. Our Senior Notes bear interest at an annual rate of 7.875%. Interest on our Senior Notes is payable on January 15 and July 15 of each year, and the first interest payment will be due on January 15, 2017. Our Senior Notes will mature on July 15, 2021. A portion of the proceeds of the Senior Notes Offering was used to repay all of the outstanding borrowings and related premium, fees and expenses under our Second Lien Notes and terminate such notes, and the remaining proceeds were used to repay borrowings under our revolving credit facility and for general business purposes, including acquisitions. Our Senior Notes are guaranteed by all of our current and future restricted subsidiaries (other than Extraction Finance Corp., the co-issuer of our Senior Notes).

Convertible Preferred Securities

On October 3, 2016, Holdings issued to affiliates of Apollo Capital Management $75.0 million in Series A Preferred Units to fund a portion of the purchase price for the Bayswater Acquisition. The Series A Preferred Units were entitled to receive a cash dividend of 10% per year, payable quarterly in arrears. We used $90.0 million of the net proceeds from the Offering to redeem the Series A Preferred Units in full, which included a premium of $15.0 million.

In addition, Holdings issued to investment funds affiliated with OZ Management LP $185.3 million in Series B Preferred Units to fund a portion of the purchase price for the Bayswater Acquisition. The Series B Preferred Units were entitled to receive a cash dividend of 10% per year, payable quarterly in arrears, and Holdings had the ability to pay up to 50% of the quarterly dividend in kind. The Series B Preferred Units were converted in connection with the closing of the Offering into shares of our Series A Preferred Stock.

Series A Preferred Stock

In connection with the Offering discussed above, we issued 185,280 shares of our Series A Preferred Stock to the holders of Holdings' Series B Preferred Units. The Series A Preferred Stock will be entitled to receive a cash dividend of 5.875% per year, payable quarterly in arrears, and we have the ability to pay such quarterly dividends in kind at a dividend rate of 10% (decreased proportionately to the extent such quarterly dividends are paid in cash). Beginning on or after the later of a) 90 days after the closing of the Offering and b) the Lock-Up Period End Date, the Series A Preferred Stock will be convertible into shares of our common stock at the election of the holders of the Series A Preferred Stock at a conversion ratio per share of Series A Preferred Stock of 61.9195. Beginning on or after the Lock-Up Period End Date, we may elect to convert the Series A Preferred Stock at a conversion ratio per share of Series A Preferred Stock of 61.9195, but only if the closing price of our common stock trades at or above a certain premium to our initial offering price, such premium to decrease with time. In certain situations, including a change of control, the Series A Preferred Stock may be redeemed for cash in amount equal to the greater of (i) 135% of the liquidation preference of the Series A Preferred Stock and (ii) a 17.5% annualized internal rate of return on the liquidation preference of the Series A Preferred Stock. The Series A Preferred Stock mature on October 15, 2021, at which time they are mandatorily redeemable for cash at par.

Public Company Expenses

General and administrative expenses related to being a publicly traded company include: Exchange Act reporting expenses; expenses associated with Sarbanes-Oxley compliance; expenses associated with listing on the NASDAQ; incremental independent auditor fees; incremental legal fees; investor relations expenses; registrar and transfer agent fees; incremental director and officer liability insurance costs; and director compensation. As a publicly traded company, we expect that general and administrative expenses will increase in future periods.

Income Taxes

In conjunction with the IPO, we converted from a limited liability company into a corporation. Prior to this conversion, we were not subject to federal or state income taxes. Accordingly, the financial data attributable to us prior to such conversion contain no provision for federal or state income taxes because the tax liability with respect to our taxable income was passed through to our members. Beginning October 12, 2016, we will be taxed as a C corporation under the Internal Revenue Code and subject to federal and state income taxes at a blended statutory rate of approximately 38% of pretax earnings.

How We Evaluate Our Operations

We use a variety of financial and operational metrics to assess the performance of our oil and gas operations, including:

- Sources of revenue;
- Sales volumes;
- Realized prices on the sale of oil, natural gas and NGL, including the effect of our commodity derivative contracts;
- Lease operating expenses (“LOE”);
- Capital expenditures; and
- Adjusted EBITDAX (a Non-GAAP measure).

Sources of Our Revenues

Our revenues are derived from the sale of our oil and natural gas production, as well as the sale of NGL that are extracted from our natural gas during processing. Our oil, natural gas and NGL revenues do not include the effects of derivatives. For the three months ended September 30, 2016, our revenues were derived 71% from oil sales, 18% from natural gas sales and 11% from NGL sales. For the three months ended September 30, 2015, our revenues were derived 76% from oil sales, 15% from natural gas sales and 8% from NGL sales. For the nine months ended September 30, 2016, our revenues were derived 74% from oil sales, 15% from natural gas sales and 11% from NGL sales. For the nine months ended September 30, 2015, our revenues were derived 81% from oil sales, 13% from natural gas sales and 6% from NGL sales. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Sales Volumes

The following table presents historical sales volumes for our properties for the three and nine months ended September 30, 2016 and 2015, respectively:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Oil (MBbl)	1,290.3	1,014.8	3,808.4	2,792.3
Natural gas (MMcf)	4,791.6	2,753.0	12,851.3	7,224.9
NGL (MBbl)	574.3	368.8	1,478.9	857.1
Total (MBoe)	2,663.2	1,842.4	7,429.2	4,853.6
Average net sales (BOE/d)	28,947.8	20,026.4	27,113.8	17,778.6

As reservoir pressures decline, production from a given well or formation decreases. Growth in our future production and reserves will depend on our ability to continue to add proved reserves in excess of our production. Accordingly, we plan to maintain our focus on adding reserves through organic growth as well as acquisitions. Our ability to add reserves through development projects and acquisitions is dependent on many factors, including takeaway capacity in our areas of operation and our ability to raise capital, obtain regulatory approvals, procure contract drilling rigs and personnel and successfully identify and consummate acquisitions.

Realized Prices on the Sale of Oil, Natural Gas and NGL

Our results of operations depend upon many factors, particularly the price of oil, natural gas and NGL and our ability to market our production effectively. Oil, natural gas and NGL prices are among the most volatile of all commodity prices. For example, during the period from January 1, 2014 to October 15, 2016, NYMEX West Texas Intermediate oil prices ranged from a high of $107.26 per Bbl to a low of $26.21 per Bbl. Average daily prices for NYMEX Henry Hub gas ranged from a high of $6.15 per MMBtu to a low of $1.64 per MMBtu during the same period. Declines in, and continued depression of, the price of oil and natural gas occurring during 2015 and continuing during 2016 are due to a combination of factors including increased U.S. supply, global economic concerns and a decision by OPEC not to reduce supply. These price variations can have a material impact on our financial results and capital expenditures.

Oil pricing is predominately driven by the physical market, supply and demand, financial markets and national and international politics. The NYMEX WTI futures price is a widely used benchmark in the pricing of domestic and imported oil in the United States. The actual prices realized from the sale of oil differ from the quoted NYMEX WTI price as a result of quality and location differentials. In the Wattenberg Field, oil is sold under various purchase contracts with monthly pricing provisions based on NYMEX pricing, adjusted for differentials.

Natural gas prices vary by region and locality, depending upon the distance to markets, availability of pipeline capacity and supply and demand relationships in that region or locality. The NYMEX Henry Hub price of natural gas is a widely used benchmark for the pricing of natural gas in the United States. Similar to oil, the actual prices realized from the sale of natural gas differ from the quoted NYMEX Henry Hub price as a result of quality and location differentials. For example, wet natural gas with a high Btu content sells at a premium to low Btu content dry natural gas because it yields a greater quantity of NGL. Location differentials to NYMEX Henry Hub prices result from variances in transportation costs based on the natural gas' proximity to the major consuming markets to which it is ultimately delivered. Also affecting the differential is the processing fee deduction retained by the natural gas processing plant generally in the form of percentage of proceeds. The price we receive for our natural gas produced in the Wattenberg Field is based on CIG prices, adjusted for certain deductions.

Our price for NGL produced in the Wattenberg Field is based on a combination of prices from the Conway hub in Kansas and Mont Belvieu in Texas where this production is marketed.

The following table provides the high and low prices for NYMEX WTI and NYMEX Henry Hub prompt month contract prices and our differential to the average of those benchmark prices for the periods indicated. In the table below, the NYMEX averages and our average realized prices, with and without derivative settlements, are calculated based on the average of each month's prices for the periods indicated. The differential varies, but our oil, natural gas and NGL normally sells at a discount to the NYMEX WTI and NYMEX Henry Hub price, as applicable.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Oil				
NYMEX WTI High ($/Bbl)	$ 48.99	$ 56.96	$ 51.23	$ 61.43
NYMEX WTI Low ($/Bbl)	$ 39.51	$ 38.24	$ 26.21	$ 38.24
NYMEX WTI Average ($/Bbl)	$ 44.94	$ 46.43	$ 41.33	$ 51.00
Average Realized Price ($/Bbl)	$ 40.12	$ 36.93	$ 35.86	$ 40.95
Average Realized Price, with derivative settlements ($/Bbl)	$ 42.73	$ 50.12	$ 41.99	$ 55.58
Average Realized Price as a % of Average NYMEX WTI	89.3 %	79.5 %	86.8 %	80.3 %
Differential ($/Bbl) to Average NYMEX WTI	$ (4.82)	$ (9.50)	$ (5.47)	$ (10.06)
Natural Gas				
NYMEX Henry Hub High ($/MMBtu)	$ 3.06	$ 2.93	$ 3.06	$ 3.23
NYMEX Henry Hub Low ($/MMBtu)	$ 2.55	$ 2.52	$ 1.64	$ 2.49
NYMEX Henry Hub Average ($/MMBtu)	$ 2.80	$ 2.73	$ 2.34	$ 2.76
Average Realized Price ($/Mcf)	$ 2.69	$ 2.72	$ 2.14	$ 2.47
Average Realized Price, with derivative settlements ($/Mcf)	$ 2.96	$ 3.01	$ 2.84	$ 2.79
Average Realized Price as a % of Average NYMEX Henry Hub	87.6 %	90.3 %	83.2 %	81.4 %
Differential ($/Mcf) to Average NYMEX Henry Hub(1)	$ (0.38)	$ (0.29)	$ (0.43)	$ (0.57)
NGL				
Average Realized Price ($/Bbl)	$ 14.71	$ 11.08	$ 13.24	$ 10.81
Averaged Realized Price as a % of Average NYMEX WTI	32.7 %	23.9 %	32.0 %	21.5 %

(1) Based on the difference between our average realized price and the NYMEX Henry Hub Average as converted into Mcf.

Lease Operating Expenses

All direct and allocated indirect costs of lifting hydrocarbons from a producing formation to the surface constituting part of the current operating expenses of a working interest. Such costs include labor, superintendence, supplies, repairs, maintenance, allocated overhead charges, workover, insurance and other expenses incidental to production, but exclude lease acquisition or drilling or completion expenses. LOEs also include expenses incurred to gather and deliver natural gas to the processing plant and/or selling point.

Capital Expenditures

For the nine months ended September 30, 2016, our aggregate drilling, completion and leasehold capital expenditures was approximately $203.1 million, excluding acquisitions. We intend to allocate approximately $335.0 million of our 2016 capital budget to the drilling of 100 gross (90 net) wells and the completion of 92 gross (82 net) wells, approximately $5.0 million to midstream, and approximately $25.0 million to leaseholds. As of September 30, 2016, 69 gross (60 net) of the 100 gross (90 net) budgeted have been drilled, and 55 gross (44 net) of the 92 gross (82 net) wells have been completed. Our capital budget excludes any amounts that were or may be paid for potential acquisitions, including the Bayswater Acquisition.

The amount and timing of these capital expenditures is within our control and subject to our management's discretion. We retain the flexibility to defer a portion of these planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil, natural gas and NGL, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners. Any postponement or elimination of our development drilling program could result in a reduction of proved reserve volumes and related standardized measure. These risks could materially affect our business, financial condition and results of operations.

Adjusted EBITDAX

Adjusted EBITDAX is not a measure of net income (loss) as determined by United States generally accepted accounting principles ("GAAP"). Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management and external users of our predecessor's financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDAX as net income (loss) adjusted for certain cash and non-cash items, including depreciation, depletion, amortization and accretion ("DD&A"), impairment of long lived assets, exploration expenses, rig termination fees, acquisition transaction expenses, commodity derivative (gain) loss, settlements on commodity derivatives, premiums paid for derivatives that settled during the period, unit-based compensation expense, amortization of debt discount and debt issuance costs, interest expense, income taxes and non-recurring charges.

Management believes Adjusted EBITDAX is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in arriving at Adjusted EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income (loss) as determined in accordance with GAAP or as an indicator of our operating performance. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital, hedging strategy and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDAX. Our computations of Adjusted EBITDAX may not be comparable to other similarly titled measure of other companies. We believe that Adjusted EBITDAX is a widely followed measure of operating performance. Additionally, our management team believes Adjusted EBITDAX is useful to an investor in evaluating our financial performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure a company’s operating performance without regard to items excluded from the calculation of such term, among other factors;
- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and
- is used by our management team for various purposes, including as a measure of operating performance, in presentations to our board of directors, as a basis for strategic planning and forecasting. Adjusted EBITDAX is also used by our Board of Directors as a performance measure in determining executive compensation.

The following table presents a reconciliation of Adjusted EBITDAX to the GAAP financial measure of net income (loss) for each of the periods indicated.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Reconciliation of Adjusted EBITDAX:				
Net income (loss)	$ (37,267)	$ 18,650	$ (210,400)	$ (38,060)
Add back:				
Depreciation, depletion, amortization, and accretion	46,680	40,880	141,317	100,170
Impairment of long lived assets	467	—	23,350	9,525
Exploration expenses	5,985	1,911	14,735	6,763
Rig termination fee	—	—	891	1,657
Acquisition transaction expenses	345	—	345	6,000
(Gain) loss on commodity derivatives	(16,225)	(46,886)	62,424	(38,478)
Settlements on commodity derivative instruments	4,787	15,067	37,947	42,441
Premiums paid for derivative that settled during the period	(132)	(934)	(5,470)	(1,046)
Unit-based compensation expense	12,315	1,510	14,922	4,583
Amortization of debt discount and debt issuance costs	15,905	1,125	18,330	3,081
Interest expense	15,311	11,557	39,584	33,269
Adjusted EBITDAX	$ 48,171	$ 42,880	$ 137,975	$ 129,905

Historical Results of Operations and Operating Expenses

Oil, Natural Gas and NGL Sales Revenues, Operating Expenses and Other Income (Expense).

The following table provides the components of our revenues, operating expenses, other income (expense) and net income (loss) for the periods indicated (in thousands):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
	(Unaudited)			
Revenues:				
Oil sales	$ 51,760	$ 37,304	$ 135,896	$ 114,768
Natural gas sales	12,792	7,472	27,730	17,707
NGL sales	8,350	4,070	19,773	9,153
Total Revenues	72,902	48,846	183,399	141,628
Operating Expenses:				
Lease operating expenses	15,480	7,493	40,819	18,806
Production taxes	6,186	4,874	16,935	12,798
Exploration expenses	5,985	1,911	14,735	6,763
Depletion, depreciation, amortization and accretion	46,680	40,880	141,317	100,170
Impairment of long lived assets	467	—	23,350	9,525
Other operating expenses	—	696	891	2,353
Acquisition transaction expenses	345	—	345	6,000
General and administrative expenses	20,071	8,568	35,189	25,437
Total Operating Expenses	95,214	64,422	273,581	181,852
Operating Loss	(22,312)	(15,576)	(90,182)	(40,224)
Other Income (Expense):				
Commodity derivatives gain (loss)	16,225	46,886	(62,424)	38,478
Interest expense	(31,216)	(12,682)	(57,914)	(36,350)
Other income	36	22	120	36
Other Income (Expense)	(14,955)	34,226	(120,218)	2,164
Net Income (Loss)	$ (37,267)	$ 18,650	$ (210,400)	$ (38,060)

The following table provides a summary of our sales volumes, average prices and operating expenses on a per BOE basis for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(unaudited)		(unaudited)	
Sales (MBoe)(1):	2,663.2	1,842.4	7,429.2	4,853.6
Oil sales (MBbl)	1,290.3	1,014.8	3,808.4	2,792.3
Natural gas sales (MMcf)	4,791.6	2,753.0	12,851.3	7,224.9
NGL sales (MBbl)	574.3	368.8	1,478.9	857.1
Sales (BOE/d)(1):	28,948	20,026	27,114	17,779
Oil sales (Bbl/d)	14,025	11,030	13,899	10,228
Natural gas sales (Mcf/d)	52,083	29,924	46,903	26,465
NGL sales (Bbl/d)	6,242	4,009	5,397	3,140
Average sales prices(2):				
Oil sales (per Bbl)	$ 40.11	$ 36.76	$ 35.68	$ 41.10
Oil sales with derivative settlements (per Bbl)	42.73	49.89	41.93	55.09
Natural gas sales (per Mcf)	2.67	2.71	2.16	2.45
Natural gas sales with derivative settlements (per Mcf)	2.94	3.01	2.84	2.77
NGL sales (per Bbl)	14.54	11.04	13.37	10.68
Average price per BOE	27.38	26.51	24.69	29.18
Average price per BOE with derivative settlements	29.12	34.18	29.06	37.71
Expense per BOE:				
Lease operating expenses	$ 5.81	$ 4.07	$ 5.49	$ 3.87
Production taxes	2.32	2.65	2.28	2.64
Exploration expenses	2.25	1.04	1.98	1.39
Depletion, depreciation, amortization, and accretion	17.53	22.19	19.02	20.64
Impairment of long lived assets	0.18	—	3.14	1.96
Other operating expenses	—	0.38	0.12	0.48
Acquisition transaction expenses	0.13	—	0.05	1.24
General and administrative expenses	7.54	4.65	4.74	5.24
Unit-based compensation	4.62	0.82	2.01	0.94
Total operating expenses per BOE	35.75	34.97	36.83	37.47

(1) One BOE is equal to six Mcf of natural gas or one Bbl of oil or NGL based on an approximate energy equivalency. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

(2) Average prices shown in the table reflect prices both before and after the effects of our settlements of our commodity derivative contracts. Our calculation of such effects includes both gains and losses on cash settlements for commodity derivatives and premiums paid or received on options that settled during the period.

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015

Oil sales revenues. Crude oil sales revenues increased by $14.5 million to $51.8 million for the three months ended September 30, 2016 as compared to crude oil sales of $37.3 million for the three months ended September 30, 2015. An increase in sales volumes between these periods contributed a $10.1 million positive impact, while an increase in crude oil prices contributed a $4.4 million positive impact due to increasing crude oil prices.

For the three months ended September 30, 2016, our crude oil sales averaged 14.0 MBbl/d. Our crude oil sales volume increased 27% to 1,290.3 MBbl in the three months ended September 30, 2016 compared to 1,014.8 MBbl for the three months ended September 30, 2015. The volume increase is primarily due to the development of our properties. For the period from October 1, 2015 through September 30, 2016, we completed 92 gross wells. Offsetting the increased production from these new wells is the normal decline on the existing producing properties.

The average price we realized on the sale of crude oil was $40.11 per Bbl for the three months ended September 30, 2016 compared to $36.76 per Bbl for the three months ended September 30, 2015.

Natural gas sales revenues. Natural gas revenues increased by $5.3 million to $12.8 million for the three months ended September 30, 2016 as compared to natural gas revenues of $7.5 million for the three months ended September 30, 2015. An increase in sales volumes between these periods contributed an $5.5 million positive impact, which was partially offset by a $0.2 million negative impact due to declining natural gas prices.

For the three months ended September 30, 2016, our natural gas sales averaged 52.1 MMcf/d. Natural gas sales volumes increased by 74% to 4,791.6 MMcf for the three months ended September 30, 2016 as compared to 2,753.0 MMcf for the three months ended September 30, 2015. The volume increase is primarily due to the development of our properties. For the period from October 1, 2015 through September 30, 2016, we completed 92 gross wells. Offsetting the increased production from these new wells is the normal decline on the existing producing properties.

The average price we realized on the sale of our natural gas was $2.67 per Mcf for the three months ended September 30, 2016 compared to $2.71 per Mcf for the three months ended September 30, 2015.

NGL sales revenues. NGL revenues increased by $4.3 million to $8.4 million for the three months ended September 30, 2016 as compared to NGL revenues of $4.1 million for the three months ended September 30, 2015. An increase in sales volumes between these periods contributed a $2.3 million positive impact, while an increase in price contributed a $2.0 million positive impact.

For the three months ended September 30, 2016, our NGL sales averaged 6.2 MBbl/d. NGL sales volumes increased by 56% to 574.3 MBbl for the three months ended September 30, 2016 as compared to 368.8 MBbl for the three months ended September 30, 2015. The volume increase is due to the development of our properties. Our NGL sales are directly associated with our natural gas sales since the majority of our natural gas volumes are processed by third parties which return a percentage of the proceeds from both residue natural gas sales and NGL sales.

The average price we realized on the sale of our NGL was $14.54 per Bbl in the three months ended September 30, 2016 compared to $11.04 per Bbl in the three months ended September 30, 2015.

Lease operating expenses. Our LOEs increased by $8.0 million to $15.5 million for the three months ended September 30, 2016, from $7.5 million for the three months ended September 30, 2015.

On a per unit basis, LOE increased from $4.07 per BOE sold for the three months ended September 30, 2015 to $5.81 per BOE sold for the three months ended September 30, 2016. The increase is primarily the result of an increase in transportation and gathering fees on gas sales as a result of the Company entering into fee-type gas contracts versus percent of proceeds. As wells mature, we expect to incur additional costs to put these wells on artificial lift, which increases costs in fuel, electricity and related expenses.

Production taxes. Our production taxes increased by $1.3 million to $6.2 million for the three months ended September 30, 2016 as compared to $4.9 million for the three months ended September 30, 2015. The increase is attributable to increased revenue as State of Colorado production taxes are calculated as a percentage of sales revenue. Production taxes as a percentage of sales revenue was 8.5% for the three months ended September 30, 2016 as compared to 10.0% for the three months ended September 30, 2015.

Exploration expenses. Our exploration expenses were $6.0 million for the three months ended September 30, 2016. We recognized $5.6 million in expense attributable to the extension of leases and $0.4 million in impairment expense attributable to the abandonment and impairment of unproved properties for the three months ended September 30, 2016. For the three months ended September 30, 2015, we recognized $1.9 million in exploration expenses. Included in exploration expense for the three months ended September 30, 2015 is $1.7 million in impairment expense attributable to the abandonment and impairment of unproved properties.

Depletion, depreciation, amortization and accretion expense. Our DD&A expense increased $5.8 million to $46.7 million for the three months ended September 30, 2016 as compared to $40.9 million for the three months ended September 30, 2015. This increase is due to more volumes being sold for the three months ended September 30, 2016 as sales increased by approximately 820.8 MBoe. On a per unit basis, DD&A expense decreased from $22.19 per BOE for the three months ended September 30, 2015 to $17.53 per BOE for the three months ended September 30, 2016.

Other operating expenses. Other operating expenses in the three months ended September 30, 2015 are comprised of a $0.7 million rig standby fees in September 2015. We did not incur any other operating expenses in the three months ended September 30, 2016.

Acquisition transaction expenses. As part of the August 2016 Acquisition and October 2016 Acquisition, we incurred $0.3 million of transaction costs associated with legal expense and due diligence for the three months ended September 30, 2016. For the three months ended September 30, 2015, we did not recognize any acquisition transaction expenses.

General and administrative expense. General and administrative ("G&A") expense increased by $11.5 million to $20.1 million for the three months ended September 30, 2016 as compared to $8.6 million for the three months ended September 30, 2015. This increase is primarily due to the acceleration of vesting on our RUAs and the associated expense during the three months ended September 30, 2016. All outstanding RUAs were accelerated in September 2016 in anticipation of our IPO, which was completed in October 2016. On a per unit basis, G&A expense increased from $4.65 per BOE sold for the three months ended September 30, 2015 to $7.54 per BOE sold for the three months ended September 30, 2016.

Our G&A expense includes the non-cash expense for unit-based compensation for equity awards granted to our employees and non-employee consultants. For the three months ended September 30, 2016, unit-based compensation expense was $12.3 million as compared to $1.5 million for the three months ended September 30, 2015. The increase in unit-based compensation expense is due to the accelerated vesting of all remaining unvested RUAs in September 2016.

Commodity derivative gain. Primarily due to the decrease in NYMEX crude oil futures prices at September 30, 2016 as compared to June 30, 2016 and change in fair value from the execution of new positions, we incurred a net gain on our commodity derivatives of $16.2 million for the three months ended September 30, 2016. Primarily due to the even larger decrease in NYMEX crude oil futures prices at September 30, 2015 as compared to June 30, 2015 and change in fair value from the execution of new positions, we incurred a net gain on our commodity derivatives of $46.9 million for the three months ended September 30, 2015. These gains are a result of our hedging program, which is used to mitigate our exposure to commodity price fluctuations. The fair value of the open commodity derivative instruments will continue to change in value until the transactions are settled and we will likely add to our hedging program. Therefore, we expect our net income (loss) to reflect the volatility of commodity price forward markets. Our cash flow will only be affected upon settlement of the transactions at the current market prices at that time. During the three months ended September 30, 2016 and 2015, we had cash settlements of commodity derivatives totaling $4.8 million and $15.1 million, respectively.

Interest expense. Interest expense consists of interest expense on our long term debt, amortization of debt discount and debt issuance costs, net of capitalized interest. For the three months ended September 30, 2016, we recognized interest expense of approximately $31.2 million as compared to $12.7 million for the three months ended September 30, 2015, as a result of borrowings under our revolving credit facility, our Senior Notes and the amortization of remaining unamortized debt issuance costs and debt discount upon the repayment of our Second Lien Notes.

We incurred interest expense for the three months ended September 30, 2016 and 2015 of approximately $12.2 million and $12.9 million, respectively, related to our revolving credit facility, our Senior Notes and to a lesser extent, our Second Lien Notes. Interest expense for the three months ended September 30, 2016 includes the accelerated amortization of our remaining unamortized debt discount and debt issuance costs of $15.1 million upon the repayment of our Second Lien Notes in July 2016, and the amortization of debt issuance costs on our Senior Notes and credit facility of $0.8 million. Also included in interest expense for the three months ended September 30, 2016 is a prepayment penalty in the amount of $4.3 million incurred upon the repayment of our Second Lien Notes. Interest expense for the three months ended September 30, 2015 includes the amortization of debt discount and debt issuance costs of $1.1 million. For the three months ended September 30, 2016 and 2015, we capitalized interest expense of $1.2 million and $1.4 million, respectively.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015

Oil sales revenues. Crude oil sales revenues increased by $21.1 million to $135.9 million for the nine months ended September 30, 2016 as compared to crude oil sales of $114.8 million for the nine months ended September 30, 2015. An increase in sales volumes between these periods contributed a $41.7 million positive impact, which was partially offset by a $20.6 million negative impact due to declining crude oil prices.

For the nine months ended September 30, 2016, our crude oil sales averaged 13.9 MBbl/d. Our crude oil sales volume increased 36% to 3,808.4 MBbl for the nine months ended September 30, 2016 compared to 2,792.3 MBbl for the nine months ended September 30, 2015. The volume increase is primarily due to the development of our properties, and to a lesser extent, the March 2015 Acquisition. For the period from October 1, 2015 through September 30, 2016, we completed 92 gross wells. Offsetting the increased production from these new wells is the normal decline on the existing producing properties.

The average price we realized on the sale of crude oil was $35.68 per Bbl for the nine months ended September 30, 2016 compared to $41.10 per Bbl for the nine months ended September 30, 2015.

Natural gas sales revenues. Natural gas revenues increased by $10.0 million to $27.7 million for the nine months ended September 30, 2016 as compared to natural gas revenues of $17.7 million for the nine months ended September 30, 2015. An increase in sales volumes between these periods contributed an $13.8 million positive impact, which was partially offset by a $3.8 million negative impact due to declining natural gas prices.

For the nine months ended September 30, 2016, our natural gas sales averaged 46.9 MMcf/d. Natural gas sales volumes increased by 78% to 12,851.3 MMcf for the nine months ended September 30, 2016 as compared to 7,224.9 MMcf for the nine months ended September 30, 2015. The volume increase is primarily due to the development of our properties, and to a lesser extent, the March 2015 Acquisition. For the period from October 1, 2015 through September 30, 2016, we completed 92 gross wells. Offsetting the increased production from these new wells is the normal decline on the existing producing properties.

The average price we realized on the sale of our natural gas was $2.16 per Mcf for the nine months ended September 30, 2016 compared to $2.45 per Mcf for the nine months ended September 30, 2015.

NGL sales revenues. NGL revenues increased by $10.6 million to $19.8 million for the nine months ended September 30, 2016 as compared to NGL revenues of $9.2 million for the nine months ended September 30, 2015. An increase in sales volumes between these periods contributed a $6.6 million positive impact, while an increase in price contributed a $4.0 million positive impact.

For the nine months ended September 30, 2016, our NGL sales averaged 5.4 MBbl/d. NGL sales volumes increased by 73% to 1,478.9 MBbl for the nine months ended September 30, 2016 as compared to 857.1 MBbl for the nine months ended September 30, 2015. The volume increase is due to the development of our properties, and to a lesser extent, the March 2015 Acquisition. Our NGL sales are directly associated with our natural gas sales since the majority of our natural gas volumes are processed by third parties which return a percentage of the proceeds from both residue natural gas sales and NGL sales.

The average price we realized on the sale of our NGL was $13.37 per Bbl in the nine months ended September 30, 2016 compared to $10.68 per Bbl in the nine months ended September 30, 2015.

Lease operating expenses. Our LOE increased by $22.0 million to $40.8 million for the nine months ended September 30, 2016, from $18.8 million for the nine months ended September 30, 2015.

On a per unit basis, LOE increased from $3.87 per BOE sold for the nine months ended September 30, 2015 to $5.49 per BOE sold for the nine months ended September 30, 2016. The increase is primarily the result of (i) an increase in transportation and gathering fees on gas sales as a result of entering into fee-type gas contracts versus percent of proceeds, and (ii) the March 2015 Acquisition, which included older vertical wells that have higher cost, on a per BOE sold basis, than our newer horizontal wells. As wells mature, we expect to incur additional costs to put these wells on artificial lift, which increases costs in fuel, electricity and related expenses.

Production taxes. Our production taxes increased by $4.1 million to $16.9 million for the nine months ended September 30, 2016 as compared to $12.8 million for the nine months ended September 30, 2015. The increase is attributable to increased revenue as State of Colorado production taxes are calculated as a percentage of sales revenue. Production taxes as a percentage of sales revenue was 9.2% for the nine months ended September 30, 2016 as compared to 9.0% for the nine months ended September 30, 2015.

Exploration expenses. Our exploration expenses were $14.7 million for the nine months ended September 30, 2016. We recognized $11.2 million in expense attributable to the extension of leases and $3.3 million in impairment expense attributable to the abandonment and impairment of unproved properties for the nine months ended September 30, 2016. For the nine months ended September 30, 2015, we recognized $6.7 million in exploration expenses. Included in exploration expense for the nine months ended September 30, 2015 is $6.2 million in impairment expense attributable to the abandonment and impairment of unproved properties.

Depletion, depreciation, amortization and accretion expense. Our DD&A expense increased $41.1 million to $141.3 million for the nine months ended September 30, 2016 as compared to $100.2 million for the nine months ended September 30, 2015. This increase is due to more volumes being sold for the nine months ended September 30, 2016 as sales increased by approximately 2,575.6 MBoe. On a per unit basis, DD&A expense decreased from $20.64 per BOE for the nine months ended September 30, 2015 to $19.02 per BOE for the nine months ended September 30, 2016.

Impairment of long lived assets. We recognized $23.4 million and $9.5 million in impairment expense on proved oil and gas properties for the nine months ended September 30, 2016 and 2015, respectively. The impairment expense for the nine months ended September 30, 2016 and 2015 is related to impairment of the assets in our Northern field. The future undiscounted cash flows did not exceed the carrying amount associated with the proved oil and gas properties in the Northern field and it was determined that the proved oil and gas properties had no remaining fair value. Therefore, the full net book value of these proved oil and gas properties were impaired at June 30, 2016 and 2015, respectively.

Other operating expenses. Other operating expenses for the nine months ended September 30, 2016 are comprised of a $0.9 million rig termination fee related to the early termination of a rig in February 2016. Other operating expenses for the nine months ended September 30, 2015 are comprised of a $1.7 million rig termination fee related to the early termination of a rig in March 2015 and a rig standby fee of $0.7 million in September 2015.

Acquisition transaction expenses. As part of the August 2016 Acquisition and October 2016 Acquisition, we incurred $0.3 million of transaction costs associated with legal expense and due diligence for the nine months ended September 30, 2016. As part of the March 2015 Acquisition, we incurred $6.0 million of non-cash transaction costs associated with a finder’s fee to an unaffiliated third-party for the nine months ended September 30, 2015. We assigned an over-riding royalty interest in the proved and unproved oil and gas properties acquired in the March 2015 Acquisition, which had a fair value of $6.0 million on the measurement date.

General and administrative expense. General and administrative (“G&A”) expense increased by $9.8 million to $35.2 million for the nine months ended September 30, 2016 as compared to $25.4 million for the nine months ended September 30, 2015. This increase is primarily due to the acceleration of vesting of our RUAs and the associated expense during the nine months ended September 30, 2016. All outstanding RUAs were accelerated in connection with our anticipated IPO completed in October 2016. On a per unit basis, G&A expense decreased from $5.24 per BOE sold for the nine months ended September 30, 2015 to $4.74 per BOE sold in the nine months ended September 30, 2016. The decrease is primarily due to our increase in sales volumes from our acquisitions and our ongoing development program.

Our G&A expense includes the non-cash expense for unit-based compensation for equity awards granted to our employees and non-employee consultants. For the nine months ended September 30, 2016, unit-based compensation expense was $14.9 million as compared to $4.6 million for the nine months ended September 30, 2015.

Commodity derivative gain (loss). Primarily due to the increase in NYMEX crude oil futures prices at September 30, 2016 as compared to December 31, 2015 and change in fair value from the execution of new positions, we incurred a net loss on our commodity derivatives of $62.4 million for the nine months ended September 30, 2016. Primarily due to a decrease in NYMEX crude oil futures prices at September 30, 2015 as compared to December 31, 2014 and change in fair value from the execution of new positions, we incurred a net gain on our commodity derivatives of $38.5 million for the nine months ended September 30, 2015. This loss during the nine months ended September 30, 2016 and gain during the nine months ended September 30, 2015 is a result of our hedging program, which is used to mitigate our exposure to commodity price fluctuations. The fair value of the open commodity derivative instruments will continue to change in value until the transactions are settled and we will likely add to our hedging program. Therefore, we expect our net income (loss) to reflect the volatility of commodity price forward markets. Our cash flow will only be affected upon settlement of the transactions at the current market prices at that time. During the nine months ended September 30, 2016 and 2015, we had cash settlements of commodity derivatives totaling $37.9 million and $42.4 million, respectively.

Interest expense. Interest expense consists of interest expense on our long term debt, amortization of debt discount and debt issuance costs, net of capitalized interest. For the nine months ended September 30, 2016, we recognized interest expense of approximately $57.9 million as compared to $36.4 million for the nine months ended September 30, 2015, as a result of borrowings under our revolving credit facility and our second lien notes.

We incurred interest expense for the nine months ended September 30, 2016 and 2015 of approximately $38.9 million and $37.4 million, respectively, related to our revolving credit facility, our Second Lien Notes and our Senior Notes. Interest expense for the nine months ended September 30, 2016 includes the accelerated amortization of our remaining unamortized debt discount and debt issuance costs of $15.1 million upon the repayment of our Second Lien Notes in July 2016, the amortization of debt discount and debt issuance costs of $3.2 million and a prepayment penalty of $4.3 million also upon the repayment of our Second Lien Notes. Interest expense for the nine months ended September 30, 2015 includes amortization of debt discount and debt issuance costs of $3.1 million. For the nine months ended September 30, 2016 and 2015, we capitalized interest expense of $3.6 million and $4.1 million, respectively.

Liquidity and Capital Resources

Our primary sources of liquidity and capital resources are cash flows generated by operating activities and borrowings under our revolving credit facility. Depending upon market conditions and other factors, we may also issue equity and debt securities if needed.

Historically, our primary sources of liquidity have been borrowings under our revolving credit facility, our Second Lien Notes, our Senior Notes (please refer to *Note 4 – Long Term Debt)*, equity provided by investors, including our management team, cash from the IPO and cash flows from operations. To date, our primary use of capital has been for the acquisition of oil and gas properties to increase our acreage position, as well as development and exploration of oil and gas properties. Our borrowings, net of unamortized debt discount and debt issuance costs, were approximately $626.6 million and $637.8 million at September 30, 2016, and December 31, 2015, respectively. We also have other contractual commitments, which are described in *Note 11 – Commitments and Contingencies.*

We plan to continue our practice of entering into hedging arrangements to reduce the impact of commodity price volatility on our cash flow from operations. Under this strategy, we intend to enter into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering approximately 50% to 80% of our projected oil production over a one-to-two year period at a given point in time, although we may from time to time hedge more or less than this approximate range.

Based on current expectations, we believe we have sufficient liquidity through our existing cash balances, cash flow from operations and available borrowings under our revolving credit facility to execute our current capital program, excluding any acquisitions we may consummate, and pay dividends on our Series A Preferred Stock.

If cash flow from operations does not meet our expectations, we may reduce our expected level of capital expenditures and/or fund a portion of our capital expenditures using borrowings under our revolving credit facility, issuances of debt and equity securities or from other sources, such as asset sales. We cannot assure you that necessary capital will be available on acceptable terms or at all. Our ability to raise funds through the incurrence of additional indebtedness could be limited by the covenants in our debt arrangements. If we are unable to obtain funds when needed or on acceptable terms, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain our production or proved reserves.

Cash Flows

The following table summarizes our cash flows for the periods indicated:

	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
	(unaudited)	
Net cash provided by operating activities	$ 97,563	$ 145,561
Net cash used in investing activities	$ (280,546)	$ (418,599)
Net cash provided by financing activities	$ 87,263	$ 316,952

Nine Months Ended September 30, 2016 Compared to the Nine Months Ended September 30, 2015

Net cash provided by operating activities. For the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015, our net cash provided by operating activities decreased by $48.0 million, primarily due to a decrease in changes in current assets and liabilities of $53.5 million, partially offset by an increase in settlements and premiums paid on commodity derivatives of $4.8 million.

Net cash used in investing activities. For the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015, our net cash used in investing activities decreased by $138.1 million primarily due to a decrease of $106.9 million used in acquisitions. Also contributing to this decrease was a decrease of $81.1 million in cash expended for drilling and completion activities and other property and equipment for the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015. Additionally, we received proceeds from the sale of land of $2.1 million which provided cash related to investing activities. Offsetting these decreases was the change in cash held in escrow of $52.1 million.

Net cash provided by financing activities. For the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015, our net cash provided by financing activities decreased by $229.7 million, primarily as a result of a decrease of $116.0 million in proceeds from the issuance of debt and borrowings under our revolving credit facility. In July 2016, we issued $550.0 million Senior Notes and used the proceeds to pay off our Second Lien Notes of $430.0 million and pay down our revolving credit facility. Also contributing to the decrease in net cash provided by financing activities was a decrease in proceeds received from the issuance of units of $102.0 million. Additionally, our costs associated with debt issuance increased by $11.3 million for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015, primarily due to the issuance of our Senior Notes in July 2016 and the amortization of remaining debt issuance costs associated with our Second Lien Notes when they were paid in full in July 2016.

Working Capital

Our working capital was a deficit of $136.4 million at September 30, 2016 and was $47.5 million at December 31, 2015. Our cash balances totaled $1.4 and $97.1 million at September 30, 2016 and December 31, 2015, respectively.

Due to the amounts that we incur related to our drilling and completion program and the timing of such expenditures, we may continue to incur working capital deficits in the future. We expect that our cash flows from operating activities and availability under our revolving credit facility after application of the estimated net proceeds from the Offering will be sufficient to fund our working capital needs. We expect that our pace of development, production volumes, commodity prices and differentials to NYMEX prices for our oil and natural gas production will be the largest variables affecting our working capital.

Debt Arrangements

Our revolving credit facility has a maximum credit amount of $500 million, subject to a borrowing base, and all of our current and future subsidiaries will be guarantors under such facility. Amounts repaid under our revolving credit facility may be re-borrowed from time to time, subject to the terms of the facility. For more information on the revolving credit facility, please see "—Revolving Credit Facility." The revolving credit facility is secured by liens on substantially all of our properties.

On May 29, 2014, we entered into a second lien credit agreement with Wilmington Trust, National Association, as administrative agent, and a syndicate of lenders for the Second Lien Notes with an aggregate principal amount equal to $430.0 million. The full balance was repaid in July 2016 with proceeds from our Senior Note Offering.

In July 2016, we closed a private offering of our unsecured 7.875% Senior Notes due 2021 that resulted in net proceeds of approximately $537.5 million. Our Senior Notes bear interest at an annual rate of 7.875%. Interest on our Senior Notes is payable on January 15 and July 15 of each year, and the first interest payment will be due on January 15, 2017. Our Senior Notes will mature on July 15, 2021. A portion of the proceeds of the Senior Notes Offering was used to repay all of the outstanding borrowings and related premium, fees and expenses under our second lien notes and terminate such notes, and the remaining proceeds were used to repay borrowings under our revolving credit facility and for general business purposes, including acquisitions. Our Senior Notes are guaranteed by all of our current and future restricted subsidiaries (other than Extraction Finance Corp., the co-issuer of our Senior Notes).

Revolving Credit Facility

The amount available to be borrowed under our revolving credit facility is subject to a borrowing base that is redetermined semiannually on each May 1 and November 1, and will depend on the volumes of our proved oil and gas reserves and estimated cash flows from these reserves and other information deemed relevant by the administrative agent under our revolving credit facility. As of September 30, 2016, the borrowing base was $350.0 million, and there was $89.0 million outstanding under our revolving credit facility. On September 14, 2016, we entered into an amendment to our revolving credit facility that, among other things, increased the borrowing base to $350.0 million. The amendment also provided that upon consummation of the Bayswater Acquisition, the borrowing base would be increased to $450.0 million. The Bayswater Acquisition closed on October 3, 2016, which triggered the borrowing base increase. As of the date of this filing, our borrowing base is $450 million. Our revolving credit facility will mature November 29, 2018.

Principal amounts borrowed will be payable on the maturity date, and interest will be payable quarterly for alternate base rate loans and at the end of the applicable interest period for Eurodollar loans. We have a choice of borrowing in Eurodollars or at the alternate base rate. Eurodollar loans bear interest at a rate per annum equal to an adjusted LIBOR rate (equal to the product of: (a) the LIBOR rate, multiplied by (b) a fraction (expressed as a decimal), the numerator of which is the number one and the denominator of which is the number one minus the reserve percentages (expressed as a decimal) on such date at which the administrative agent under our revolving credit facility is required to maintain reserves on 'Eurocurrency Liabilities' as defined in and pursuant to Regulation D of the Board of

Governors of the Federal Reserve System) plus an applicable margin ranging from 200 to 300 basis points, depending on the percentage of our borrowing base utilized. Alternate base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank's reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the adjusted one-month LIBOR rate (as calculated above) plus 100 basis points, plus an applicable margin ranging from 100 to 200 basis points, depending on the percentage of our borrowing base utilized. As of September 30, 2016, borrowings under our revolving credit facility had a weighted average interest rate of 3.0%. We may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs.

The revolving credit facility is secured by liens on substantially all of our properties and guarantees from us and our current and future subsidiaries. The revolving credit facility contains restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make investments;
- make certain changes to our capital structure;
- make or declare dividends;
- hedge future production or interest rates;
- enter into transactions with our affiliates;
- holding cash balances in excess of certain thresholds while carrying a balance of our revolving credit facility;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

The revolving credit facility requires us to maintain the following financial ratios:

- a current ratio, which is the ratio of our consolidated current assets (includes unused commitments under our revolving credit facility and unrestricted cash and excludes derivative assets) to our consolidated current liabilities (excludes obligations under our revolving credit facility, the second lien notes and certain derivative assets), of not less than 1.0 to 1.0 as of the last day of any fiscal quarter; and
- a maximum leverage ratio, which is the ratio of (i) consolidated debt less cash balances in excess of certain thresholds to (ii) our consolidated EBITDAX for the four fiscal quarter period most recently ended, not to exceed 4.0 to 1.0 as of the last day of such fiscal quarter; *provided that* (a) for the quarters ending between December 31, 2016 through December 31, 2017, annualized EBITDAX will be based on the last six months' consolidated EBITDAX multiplied by 2, and (b) for the quarter ending March 31, 2018, annualized EBITDAX will be based on the last nine months' consolidated EBITDAX multiplied by 4/3, and (c) for the quarters ending on or after June 30, 2018, annualized EBITDAX will be based on the last twelve months' consolidated EBITDAX.

Second Lien Notes

As of September 30, 2016, we had no borrowings outstanding under our Second Lien Notes where, among others, we acted as guarantors. In connection with the closing of the Senior Notes Offering, we repaid all borrowings and related premium, fees and expenses under our Second Lien Notes and terminated such notes. Borrowings under our formerly outstanding Second Lien Notes bore interest at an aggregate weighted average rate equal to 10.7% per annum.

Senior Notes

In July 2016, we closed a private offering of our unsecured 7.875% Senior Notes due 2021 that resulted in net proceeds of approximately $537.5 million. Our Senior Notes bear interest at an annual rate of 7.875%. Interest on our Senior Notes is payable on January 15 and July 15 of each year, and the first interest payment will be due on January 15, 2017. Our Senior Notes will mature on July 15, 2021.

We may, at our option, redeem all or a portion of our Senior Notes at any time on or after July 15, 2018. We are also entitled to redeem up to 35% of the aggregate principal amount of our Senior Notes before July 15, 2018, with an amount of cash not greater than the net proceeds that we raise in certain equity offerings at a redemption price equal to 107.875% of the principal amount of our Senior Notes being redeemed plus accrued and unpaid interest, if any, to the redemption date. In addition, prior to July 15, 2018, we may redeem some or all of our Senior Notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date, plus a “make-whole” premium. If we experience certain kinds of changes of control, holders of our Senior Notes may have the right to require us to repurchase their notes at 101% of the principal amount of the notes, plus accrued and unpaid interest, if any, to the date of purchase.

Our Senior Notes are our senior unsecured obligations and rank equally in right of payment with all of our other senior indebtedness and senior to any of our subordinated indebtedness. Our Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by each of our current and future restricted subsidiaries (other than Extraction Finance Corp., the co-issuer of our Senior Notes) that guarantees our indebtedness under a credit facility. The notes are effectively subordinated to all of our secured indebtedness (including all borrowings and other obligations under our revolving credit facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated in right of payment to all existing and future indebtedness and other liabilities (including trade payables) of any future subsidiaries that do not guarantee the notes.

Critical Accounting Policies and Estimates

There were no changes to our critical accounting policies from those disclosed in our Prospectus filed on October 11, 2016.

Recent Accounting Pronouncements

For information regarding new accounting policies or updates to existing accounting policies as a result of new accounting pronouncements, please refer to Note 2 - *Basis of Presentation and Significant Accounting Policies* in Part I, Item 1 of this Quarterly Report, which is incorporated herein by reference.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

We are exposed to market risk, including the effects of adverse changes in commodity prices and interest rates as described below. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in oil, natural gas and NGL prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing that we receive for our oil, natural gas and NGL production. Pricing for oil, natural gas and NGL has been volatile and unpredictable for several years, and this volatility is expected to continue in the future. The prices we receive for our oil, natural gas and NGL production depend on many factors outside of our control, such as the strength of the global economy and global supply and demand for the commodities we produce.

To reduce the impact of fluctuations in oil prices on our revenues, we have periodically entered into commodity derivative contracts with respect to certain of our oil and natural gas production through various transactions that limit the downside of future prices received. We plan to continue our practice of entering into such transactions to reduce the impact of commodity price volatility on our cash flow from operations. Future transactions may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into collars, whereby we receive the excess, if any, of the fixed floor over the floating rate or pay the excess, if any, of the floating rate over the fixed ceiling price. These hedging activities are intended to support oil prices at targeted levels and to manage our exposure to oil price fluctuations.

The following tables present our derivative positions related to crude oil and natural gas sales in effect as of September 30, 2016:

	For the Three Months Ended						
	December 31, 2016	March 31, 2017	June 30, 2017	September 30, 2017	December 31, 2017	March 31, 2018	June 30, 2018
NYMEX WTI(1) Crude Swaps:							
Notional volume (Bbl)	525,000	1,050,000	600,000	150,000	150,000	—	—
Weighted average fixed price ($/Bbl)	$ 38.70	$ 43.11	$ 45.20	$ 44.13	$ 44.13	$ —	$ —
NYMEX WTI(1) Crude Sold Calls:							
Notional volume (Bbl)	839,000	600,000	1,000,000	1,200,000	1,200,000	100,000	—
Weighted average fixed price ($/Bbl)	$ 55.15	$ 55.25	$ 53.35	$ 53.06	$ 53.49	$ 55.00	$ —
NYMEX WTI(1) Crude Sold Puts:							
Notional volume (Bbl)	750,000	775,000	875,000	1,025,000	1,125,000	—	—
Weighted average purchased put price ($/Bbl)	$ 45.00	$ 35.65	$ 35.97	$ 36.85	$ 36.87	$ —	$ —
NYMEX WTI(1) Crude Purchased Puts:							
Notional volume (Bbl)	1,125,000	600,000	1,000,000	1,200,000	1,200,000	—	—
Weighted average purchased put price ($/Bbl)	$ 51.44	$ 47.33	$ 45.48	$ 45.95	$ 46.32	$ —	$ —
NYMEX HH(2) Natural Gas Swaps:							
Notional volume (MMBtu)	3,315,000	4,240,000	4,840,000	5,770,000	5,770,000	600,000	600,000
Weighted average fixed price ($/MMBtu)	$ 3.09	$ 3.03	$ 3.02	$ 3.02	$ 3.02	$ 3.03	$ 3.03
CIG(3) Basis Gas Swaps:							
Notional volume (MMBtu)	990,000	990,000	—	—	—	—	—
Weighted average fixed basis price ($/MMBtu)	$ (0.19)	$ (0.19)	$ —	$ —	$ —	$ —	$ —

(1) NYMEX WTI refers to West Texas Intermediate crude oil price on the New York Mercantile Exchange

(2) NYMEX HH refers to the Henry Hub natural gas price on the New York Mercantile Exchange

(3) CIG refers to the NYMEX HH settlement price less the fixed basis price, the Rocky Mountains (CIGC) Inside FERC settlement price.

As of September 30, 2016, the fair market value of our oil derivative contracts was a net liability of $27.1 million. Based on our open oil derivative positions at September 30, 2016, a 10% increase in the NYMEX WTI price would increase our net oil derivative liability by approximately $32.4 million, while a 10% decrease in the NYMEX WTI price would decrease our net oil derivative liability by approximately $30.2 million. As of September 30, 2016, the fair market value of our natural gas derivative contracts was a net liability of $0.9 million. Based upon our open commodity derivative positions at September 30, 2016, a 10% increase in the NYMEX Henry Hub price would increase our net natural gas derivative liability by approximately $7.4 million, while a 10% decrease in the NYMEX Henry Hub price would decrease our net natural gas derivate liability by approximately $7.4 million. Please see “—Derivative Arrangements.”

Counterparty and Customer Credit Risk

Our cash and cash equivalents are exposed to concentrations of credit risk. We manage and control this risk by investing these funds with major financial institutions. We often have balances in excess of the federally insured limits.

We sell oil, natural gas and NGL to various types of customers, including pipelines and refineries. Credit is extended based on an evaluation of the customer’s financial conditions and historical payment record. The future availability of a ready market for oil, natural gas and NGL depends on numerous factors outside of our control, none of which can be predicted with certainty. For the nine-months ended September 30, 2016, we had certain major customers that exceeded 10% of total oil, natural gas and NGL revenues. We do not believe the loss of any single purchaser would materially impact its operating results because oil, natural gas and NGL are fungible products with well-established markets and numerous purchasers.

At September 30, 2016, we had commodity derivative contracts with six counterparties. We do not require collateral or other security from counterparties to support derivative instruments; however, to minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market-makers. Additionally, we use master netting agreements to minimize credit-risk exposure. The creditworthiness of our counterparties is subject to periodic review. Three of the six counterparties to the derivative instruments are highly rated entities with corporate ratings at A3 classifications or above by Moody’s. The other three counterparties had a corporate rating of Baa1 by Moody’s. For the three and nine months ended September 30, 2016 and 2015, we did not incur any losses with respect to counterparty contracts. None of our existing derivative instrument contracts contains credit-risk related contingent features.

Interest Rate Risk

At September 30, 2016, we had $89.0 million of variable-rate debt outstanding, with a weighted average interest rate of LIBOR plus 2.3%. Assuming no change in the amount outstanding, the impact on interest expense of a 1% increase or decrease in the average interest rate would be approximately $0.9 million per year. We may begin entering into interest rate swap arrangements on a portion of our outstanding debt to mitigate the risk of fluctuations in LIBOR. See “—Liquidity and Capital Resources—Debt Arrangements.”

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Securities Exchange Act of 1934 (the "Exchange Act"), we have evaluated, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Quarterly Report on Form 10-Q. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of September 30, 2016.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended September 30, 2016 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Information regarding our legal proceedings can be found in Note 11, *Commitments and Contingencies – Legal Matters*, to our condensed consolidated financial statements included elsewhere in this report.

ITEM 1A. RISK FACTORS

Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock are described under *Risk Factors*, included in our final prospectus dated October 11, 2016 and filed with the SEC pursuant to Rule 424(b) under the Securities Act, on October 13, 2016, as amended (the "Final Prospectus"). This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

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

In connection with the completion of the IPO, Holdings merged with and into us and we were the surviving entity to such merger, with the equity holders in Holdings, including the holders of restricted units and incentive units, receiving an aggregate of 108,460,231 shares of common stock, with the allocation of such shares among Holdings' equity holders determined by reference to our implied valuation based on the 10-day volume weighted average price of the common stock following the closing of the Offering, in accordance with the distribution mechanics set forth in the Holdings LLC Agreement.

The issuance of such membership interests did not involve any underwriters, underwriting discounts or commissions or a public offering, and such issuance was exempt from registration requirements pursuant to Section 4(a)(2) of the Securities Act of 1933, as amended.

Use of Proceeds

On October 11, 2016 our registration statement on Form S-1 (SEC Registration No. 333-213634), as amended through the time of its effectiveness, that we filed with the SEC relating to the Offering was declared effective. Credit Suisse Securities (USA) LLC, Barclays Capital Inc. and Goldman, Sachs & Co. served as representatives of the several underwriters for the Offering. The offering did not terminate before all of the shares in the Offering that were registered in the registration statement were sold. In October 2016, we closed the Offering of 38,333,333 shares of common stock, which includes the full exercise by the underwriters of the over-allotment option of 5,000,000 shares, at a price to the public of $19.00 per share ($17.955 per share net of underwriting discounts and commissions), resulting in gross proceeds of $728.3 million, or estimated net proceeds of $683.7 million after deducting underwriting discounts and commissions.

We used the net proceeds from the offering to redeem (i) the Series A Preferred Units and (ii) repay borrowings under our revolving credit facility. The remaining net proceeds will be used for general corporate purposes, including funding our 2016 and 2017 capital expenditures.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

(a) Exhibits:

The exhibits listed on the accompanying Exhibit Index are filed, furnished or incorporated by reference as part of this report, and such Exhibit Index is incorporated herein by reference.

SIGNATURES

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

Date: November 7, 2016.

Extraction Oil & Gas, Inc.

By: /S/ MARK A. ERICKSON
Mark A. Erickson
Chairman and Chief Executive Officer
(principal executive officer)

By: /S/ RUSSELL T. KELLEY JR.
Russell T. Kelley, Jr.
Chief Financial Officer
(principal financial officer)

INDEX TO EXHIBITS

Exhibit Number	Description
**2.1	Agreement and Plan of Merger, dated October 17, 2016, by and between Extraction Oil & Gas, Inc. and Extraction Oil & Gas Holdings, LLC. (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
**3.1	Certificate of Incorporation of Extraction Oil & Gas, Inc., dated October 11, 2016 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
**3.2	Certificate of Designations of Series A Preferred Stock of Extraction Oil & Gas, Inc., filed with the Secretary of State of the State of Delaware on October 17, 2016 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
**3.3	Bylaws of Extraction Oil & Gas, Inc., dated October 11, 2016 (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
**4.1	Amended and Restated Registration Rights Agreement, dated October 17, 2016, by and among Extraction Oil & Gas, Inc. and the other persons named therein (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
**4.2	Registration Rights Agreement, dated October 3, 2016, by and among Extraction Oil & Gas, LLC, Extraction Oil & Gas Holdings, LLC and the other persons named therein (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
**4.3	Supplemental Indenture, dated October 17, 2016, by and among Extraction Oil & Gas, Inc., Extraction Finance Corp., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
†**4.4	Extraction Oil & Gas, Inc. 2016 Long Term Incentive Plan (incorporated by reference to Exhibit 4.4 to the Company's Registration Statement on Form S-8 (File No. 333-214089) filed with the Commission on October 13, 2016).
†**10.1	Form of Restricted Stock Unit Award Agreement (for Employees) (incorporated by reference to Exhibit 4.5 to the Company's Registration Statement on Form S-8 (File No. 333-214089) filed with the Commission on October 13, 2016).
†**10.2	Form of Restricted Stock Unit Award Agreement (for Directors) (incorporated by reference to Exhibit 4.6 to the Company's Registration Statement on Form S-8 (File No. 333-214089) filed with the Commission on October 13, 2016).
†**10.3	Form of Stock Option Award Agreement (incorporated by reference to Exhibit 4.7 to the Company's Registration Statement on Form S-8 (File No. 333-214089) filed with the Commission on October 13, 2016).

†**10.4	Employment Agreement dated as of October 11, 2016 among the Company, XOG Services, LLC, and Mark A. Erickson (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
†**10.5	Employment Agreement dated as of October 11, 2016 among the Company, XOG Services, LLC, and Matthew R. Owens (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
†**10.6	Employment Agreement dated as of October 11, 2016 among the Company, XOG Services, LLC, and Russell T. Kelley, Jr. (incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
†**10.7	Indemnification Agreement (Mark A. Erickson) (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
†**10.8	Indemnification Agreement (Matthew R. Owens) (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
†**10.9	Indemnification Agreement (Russell T. Kelley, Jr.) (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016)..
†**10.10	Indemnification Agreement (John S. Gaensbauer) (incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
†**10.11	Indemnification Agreement (Peter A. Leidel) (incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
†**10.12	Indemnification Agreement (Marvin M. Chronister) (incorporated by reference to Exhibit 10.8 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
†**10.13	Indemnification Agreement (Patrick D. O'Brien) (incorporated by reference to Exhibit 10.9 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
†**10.14	Employment Agreement effective as of November 1, 2016 among the Company and Tom L. Brock (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 31, 2016).
†**10.15	Indemnification Agreement (Tom L. Brock) (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 31, 2016).

**10.16	Credit Agreement, dated as of September 4, 2014, by and among Extraction Oil & Gas Holdings, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Registration Statement on Form S-1 (File No. 333-213634) filed with the Commission on September 14, 2016).
**10.17	Amendment No. 1 to the Credit Agreement, dated as of September 24, 2014, by and among Extraction Oil & Gas Holdings, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Company's Registration Statement on Form S-1 (File No. 333-213634) filed with the Commission on September 14, 2016).
**10.18	Amendment No. 2 to the Credit Agreement, dated as of November 10, 2014, by and among Extraction Oil & Gas Holdings, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.3 to the Company's Registration Statement on Form S-1 (File No. 333-213634) filed with the Commission on September 14, 2016).
**10.19	Amendment No. 3 to the Credit Agreement, dated as of December 30, 2014, by and among Extraction Oil & Gas Holdings, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.4 to the Company's Registration Statement on Form S-1 (File No. 333-213634) filed with the Commission on September 14, 2016).
**10.20	Amendment No. 4 to the Credit Agreement, dated as of May 27, 2015, by and among Extraction Oil & Gas Holdings, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1 (File No. 333-213634) filed with the Commission on September 14, 2016).
**10.21	Amendment No. 5 to the Credit Agreement, dated as of September 1, 2015, by and among Extraction Oil & Gas Holdings, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.6 to the Company's Registration Statement on Form S-1 (File No. 333-213634) filed with the Commission on September 14, 2016).
**10.22	Amendment No. 6 to the Credit Agreement, dated as of September 10, 2015, by and among Extraction Oil & Gas Holdings, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.7 to the Company's Registration Statement on Form S-1 (File No. 333-213634) filed with the Commission on September 14, 2016).
**10.23	Amendment No. 7 to the Credit Agreement, dated as of December 15, 2015, by and among Extraction Oil & Gas Holdings, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-1 (File No. 333-213634) filed with the Commission on September 14, 2016).
**10.24	Amendment No. 8 to the Credit Agreement, dated as of June 13, 2016, by and among Extraction Oil & Gas Holdings, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.9 to the Company's Registration Statement on Form S-1 (File No. 333-213634) filed with the Commission on September 14, 2016).

**10.25	Amendment No. 9 to the Credit Agreement, dated as of August 12, 2016, by and among Extraction Oil & Gas Holdings, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.10 to the Company's Registration Statement on Form S-1 (File No. 333-213634) filed with the Commission on September 14, 2016).
**10.26	Amendment No. 10 to the Credit Agreement, dated as of September 14, 2016, by and among Extraction Oil & Gas Holdings, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto incorporated by reference to Exhibit 10.11 to the Company's Registration Statement on Form S-1 (File No. 333-213634) filed with the Commission on September 26, 2016).
*31.1	Certification of Chief Executive Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934.
*31.2	Certification of Chief Financial Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934.
*32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101	Interactive Data Files

† Management contract or compensatory plan or agreement.
* Filed herewith.
** Previously filed.

EXHIBIT 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Mark A. Erickson, certify that:

1. I have reviewed this quarterly report of Extraction Oil & Gas, Inc. (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 7, 2016

/S/ MARK A. ERICKSON

Mark A. Erickson
Chief Executive Officer and Chairman
(Principal Executive Officer)

EXHIBIT 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Russell T. Kelley, Jr., certify that:

1. I have reviewed this quarterly report of Extraction Oil & Gas, Inc. (the “registrant”);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    c. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: November 7, 2016

/S/ RUSSELL T. KELLEY JR.

Russell T. Kelley, Jr.
Chief Financial Officer
(Principal Financial Officer)

EXHIBIT 32.1

CERTIFICATION OF
CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER
UNDER SECTION 906 OF THE
SARBANES OXLEY ACT OF 2002, 18 U.S.C. § 1350

In connection with the quarterly report of Extraction Oil & Gas, Inc. (the "Company"), as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Mark A. Erickson, Chief Executive Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: November 7, 2016

/S/ MARK A. ERICKSON

Mark A. Erickson
Chief Executive Officer and Chairman
(Principal Executive Officer)

EXHIBIT 32.2

CERTIFICATION OF
CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER
UNDER SECTION 906 OF THE
SARBANES OXLEY ACT OF 2002, 18 U.S.C. § 1350

In connection with the quarterly report of Extraction Oil & Gas, Inc. (the "Company"), as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Russell T. Kelley, Jr., Chief Financial Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: November 7, 2016

/S/ RUSSELL T. KELLEY JR.

Russell T. Kelley, Jr.
Chief Financial Officer
(Principal Financial Officer)