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 March 31, 2017

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 ☐

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, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer", "accelerated filer", "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer	☒	Smaller reporting company	☐
Emerging growth company	☒		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange act. ☒

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 May 5, 2017 was 171,834,605.

EXTRACTION OIL & GAS, INC.
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GLOSSARY OF OIL AND GAS TERMS

Unless indicated otherwise or the context otherwise requires, references in this Quarterly Report on Form 10-Q ("Quarterly Report") to the "Company," "Extraction," "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 in our Annual Report on Form 10-K ("Annual Report"). 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 consolidated financial statements for the three months ended March 31, 2016 in this Quarterly Report.

The terms defined in this section are used throughout this Quarterly Report:

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

"Bbl/d" means Bbl per day.

"Btu" means on 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.

"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.

"CIG" means Colorado Interstate Gas.

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

"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" or *"horizontal well"* 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 NGL.

"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.

"Overriding royalty" means an interest in the gross revenues or production over and above the landowner's royalty carved out of the working interest and also unencumbered with any expenses of operation, development or maintenance.

"Operator" means the individual or company responsible to the working interest owners for the exploration, development and production of an oil or natural gas well or lease.

"Producing well" means a well that is producing oil or natural gas or that is capable of production.

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

"Proved reserves" means those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

"Proved undeveloped reserves" means proved 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. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time. Under no circumstances shall estimates of proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

"Reasonable certainty" means a high degree of confidence that the reserves quantities will be recovered, when a deterministic method is used. A high degree of confidence exists if the reserves quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical and geochemical), engineering and economic data are made to estimated ultimate recovery ("EUR") with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

"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.

"SEC" means the Securities and Exchange Commission.

"Spacing" means the distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

"Undeveloped acreage" means lease acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether or not such acreage contains proved reserves.

"Undeveloped leasehold acreage" means the leased acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage contains estimated net proved reserves.

"Unit" means the joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"Wattenberg Field" means the Greater Wattenberg Area within the Denver-Julesburg Basin of Colorado as defined by the Colorado Oil and Gas Conservation Commission, which are the lands from and including Townships 2 South to 7 North and Ranges 61 West to 69 West, Six Principal Median.

"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, INC.
CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)
(Unaudited)

	March 31, 2017	December 31, 2016
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 284,551	$ 588,736
Accounts receivable		
Trade	21,775	23,154
Oil, natural gas and NGL sales	31,066	34,066
Inventory and prepaid expenses	9,715	7,722
Total Current Assets	347,107	653,678
Property and Equipment (successful efforts method), at cost:		
Proved oil and gas properties	2,081,304	1,851,052
Unproved oil and gas properties	479,710	452,577
Wells in progress	141,423	98,747
Less: accumulated depletion, depreciation and amortization	(451,458)	(402,912)
Net oil and gas properties	2,250,979	1,999,464
Other property and equipment, net of accumulated depreciation	32,677	32,721
Net Property and Equipment	2,283,656	2,032,185
Non-Current Assets:		
Cash held in escrow	22,318	42,200
Commodity derivative asset	5,724	—
Goodwill and other intangible assets, net of accumulated amortization	54,526	54,489
Other non-current assets	1,947	2,224
Total Non-Current Assets	84,515	98,913
Total Assets	$ 2,715,278	$ 2,784,776
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 88,166	$ 131,134
Revenue payable	34,499	35,162
Production taxes payable	27,080	27,327
Commodity derivative liability	9,002	56,003
Accrued interest payable	9,148	19,621
Asset retirement obligations	4,375	5,300
Total Current Liabilities	172,270	274,547
Non-Current Liabilities:		
Senior Notes, net of unamortized debt issuance costs	538,684	538,141
Production taxes payable	45,342	35,838
Commodity derivative liability	—	6,738
Other non-current liabilities	3,408	3,466
Asset retirement obligations	53,751	50,808
Deferred tax liability	111,156	106,026
Total Non-Current Liabilities	752,341	741,017
Commitments and Contingencies—Note 11		
Total Liabilities	924,611	1,015,564
Series A Convertible Preferred Stock, $0.01 par value; 50,000,000 shares authorized; 185,280 issued and outstanding	154,360	153,139
Stockholders' Equity:		
Common stock, $0.01 par value; 900,000,000 shares authorized; 171,834,605 issued and outstanding	1,718	1,718
Additional paid-in capital	2,079,108	2,067,590
Accumulated deficit	(444,519)	(453,235)
Total Stockholders' Equity	1,636,307	1,616,073
Total Liabilities and Stockholders' Equity	$ 2,715,278	$ 2,784,776

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

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

	For the Three Months Ended March 31, 2017	2016
Revenues:		
Oil sales	$ 52,128	$ 34,088
Natural gas sales	19,897	6,606
NGL sales	17,614	4,438
Total Revenues	89,639	45,132
Operating Expenses:		
Lease operating expenses	22,323	11,970
Production taxes	6,453	4,490
Exploration expenses	10,812	2,831
Depletion, depreciation, amortization and accretion	50,653	45,308
Impairment of long lived assets	675	446
Other operating expenses	451	891
Acquisition transaction expenses	68	—
General and administrative expenses	25,688	7,140
Total Operating Expenses	117,123	73,076
Operating Loss	(27,484)	(27,944)
Other Income (Expense):		
Commodity derivatives gain (loss)	50,422	(4,036)
Interest expense	(9,660)	(13,568)
Other income	568	28
Total Other Income (Expense)	41,330	(17,576)
Net Income (Loss) Before Income Taxes	13,846	(45,520)
Income Tax Expense	5,130	—
Net Income (Loss)	$ 8,716	$ (45,520)
Earnings Per Common Share (Note 10)		
Basic and diluted	$ 0.03	
Weighted Average Common Shares Outstanding		
Basic and diluted	171,835	

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

EXTRACTION OIL & GAS, INC.
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN MEMBERS' AND STOCKHOLDERS' EQUITY
(In thousands)
(Unaudited)

	Members' Units			Common Stock				
	Tranche A Units	Preferred Tranche C Units	Amount	Shares	Amount	Additional Paid in Capital	Retained Earnings (Deficit)	Total Equity
Balance at January 1, 2016	231,101	78,444	$ 751,466	—	$ —	$ —	$ 2,766	$ 754,232
Restricted stock units issued	304	—	—	—	—	—	—	—
Unit-based compensation	—	—	1,368	—	—	—	—	1,368
Net loss	—	—	—	—	—	—	(45,520)	(45,520)
Balance at March 31, 2016	231,405	78,444	$ 752,834	—	$ —	$ —	$ (42,754)	$ 710,080
Balance at January 1, 2017	—	—	$ —	171,835	$ 1,718	$ 2,067,590	$ (453,235)	$ 1,616,073
Common stock issuance costs	—	—	—	—	—	(210)	—	(210)
Stock-based compensation	—	—	—	—	—	15,745	—	15,745
Series A Preferred Stock dividends	—	—	—	—	—	(2,721)	—	(2,721)
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	—	(1,296)	—	(1,296)
Net income	—	—	—	—	—	—	8,716	8,716
Balance at March 31, 2017	—	—	$ —	171,835	$ 1,718	$ 2,079,108	$ (444,519)	$ 1,636,307

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

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

	For the Three Months Ended March 31, 2017	2016
Cash flows from operating activities:		
Net income (loss)	$ 8,716	$ (45,520)
Reconciliation of net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, amortization and accretion	50,653	45,308
Abandonment and impairment of unproved properties	2,735	—
Impairment of long lived assets	675	446
Loss on sale of property and equipment	451	—
Amortization of debt issuance costs and debt discount	845	1,198
Deferred rent	101	242
Commodity derivatives (gain) loss	(50,422)	4,036
Settlements on commodity derivatives	(9,129)	29,072
Premiums paid on commodity derivatives	—	(30)
Deferred income tax expense	5,130	—
Unit and stock-based compensation	15,745	1,368
Changes in current assets and liabilities:		
Accounts receivable—trade	1,096	6,107
Accounts receivable—oil, natural gas and NGL sales	3,000	(557)
Inventory and prepaid expenses	140	252
Accounts payable and accrued liabilities	(7,913)	(17,738)
Revenue payable	(663)	(3,632)
Production taxes payable	9,248	5,816
Accrued interest payable	(10,473)	11,268
Asset retirement expenditures	(602)	(96)
Net cash provided by operating activities	19,333	37,540
Cash flows from investing activities:		
Oil and gas property additions	(334,606)	(79,086)
Acquired oil and gas properties	(3,830)	—
Sale of other property and equipment	2,000	2,148
Other property and equipment additions	(3,231)	(1,586)
Cash held in escrow	19,882	—
Net cash used in investing activities	(319,785)	(78,524)
Cash flows from financing activities:		
Borrowings under credit facility	—	10,000
Dividends on Series A Preferred Stock	(2,237)	—
Debt issuance costs	(14)	—
Equity issuance costs	(1,482)	(214)
Net cash provided by (used in) financing activities	(3,733)	9,786
Decrease in cash and cash equivalents	(304,185)	(31,198)
Cash and cash equivalents at beginning of period	588,736	97,106
Cash and cash equivalents at end of the period	$ 284,551	$ 65,908
Supplemental cash flow information:		
Property and equipment included in accounts payable and accrued liabilities	$ 71,308	$ 60,020
Cash paid for interest	$ 21,749	$ 2,064
Accretion of beneficial conversion feature of Series A Preferred Stock	$ 1,296	$ —

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

EXTRACTION OIL & GAS, INC.
NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Business and Organization

Extraction Oil & Gas, Inc. (the "Company" or "Extraction") is an independent oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves in the Rocky Mountain region, primarily in the Wattenberg Field of the Denver-Julesburg Basin (the "DJ Basin") of Colorado. The Company has nine subsidiaries, focused on the acquisition, development and production of oil, natural gas and NGL reserves in the Rocky Mountain region, as well as the design and support of midstream assets to gather and process crude oil and gas production focused in the DJ Basin of Colorado. Extraction is a public company listed for trading on the NASDAQ Global Select Market under the symbol "XOG".

The condensed consolidated financial statements for the three months ended March 31, 2016 are based on the financial statements of the Company's accounting predecessor, Extraction Oil & Gas Holdings, LLC, prior to the corporate reorganization (the "Corporate Reorganization"), pursuant to which, in connection with the initial public offering ("IPO") of the Company, (i) on October 11, 2016, a former subsidiary of Extraction Oil & Gas Holdings, LLC, Extraction Oil & Gas, LLC, converted into the Company, and (ii) on October 17, 2016, Holdings merged with and into the Company with the Company as the surviving entity. For further information on the Corporate Reorganization please refer to the Company's Annual Report on Form 10-K for the year ended December 31, 2016 ("Annual Report").

Note 2—Basis of Presentation, Significant Accounting Policies and Recent Accounting Pronouncements

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") and the SEC rules and regulation for interim financial reporting. 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. Interim condensed consolidated financial statements and the year-end balance sheet do not include all of the information and notes required by GAAP for audited annual consolidated financial statements. These unaudited financial statements should be read in conjunction with the Company's audited financial statements and notes included in the Company's Annual Report.

Significant Accounting Policies

The significant accounting policies followed by the Company are set forth in Note 2 to the Company's consolidated financial statements in its Annual Report, and are supplemented by the notes to the unaudited condensed consolidated financial statements in this report. These unaudited condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes included in the Company's Annual Report.

Recent Accounting Pronouncements

In February 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2017-05, which provides clarification regarding the guidance on accounting for the derecognition of nonfinancial assets. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2017, including interim reporting periods within that reporting period. Early adoption is permitted for fiscal years beginning after December 15, 2016, including the interim reporting periods within that fiscal year. The Company is currently evaluating this new standard to determine the potential impact to its financial statements and related disclosures.

In January 2017, the FASB issued ASU No. 2017-04, which simplifies how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. Step 2 measures a goodwill impairment loss by comparing the implied fair of a reporting unit's goodwill with the carrying amount. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2019. Early adoption is permitted for interim and annual goodwill impairment tests performed on testing dates after January 1, 2017. The Company is currently evaluating this new standard to determine the potential impact to its financial statements and related disclosures.

In January 2017, the FASB issued ASU No. 2017-01, which clarifies the definition of a business when evaluating whether transactions should be accounted for as acquisitions or disposals of assets or businesses. 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 for transactions for which the acquisition date occurs before the issuance date or effective date of the amendments, only when the transaction has not been reported in the financial statements that have been issued. The Company is currently evaluating this new standard to determine the potential impact to its financial statements and related disclosures.

In December 2016, the FASB issued ASU No. 2016-19, which among other technical corrections and improvements, adds a reference to guidance to use when accounting for internal-use software licensed from third parties that is within the scope of Subtopic 350-40. For public entities, the guidance is effective upon issuance of the ASU. Adoption is permitted either (1) prospectively to all arrangements entered into or materially modified after the effective date or (2) retrospectively. The Company elected to adopt this guidance prospectively during the fourth quarter of 2016, which resulted in the capitalization of internal-use software licensed from third parties to goodwill and other intangible assets on the consolidated balance sheets. Costs are amortized over their respective service periods and expensed to depletion, depreciation, and amortization on the consolidated statements of operations.

In November 2016, the FASB issued ASU No. 2016-18, which intends to clarify how entities should present restricted cash and restricted cash equivalents in the statement of cash flows. This amendment will be effective retrospectively for reporting periods beginning after December 15, 2017, and early adoption is permitted. The Company is currently evaluating this new standard to determine the potential impact to its financial statements and related disclosures.

In August 2016, the FASB issued 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. In addition, in November 2016, the FASB issued ASU 2016-18, which requires that amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. 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 was effective for public companies for annual and interim reporting periods beginning after December 15, 2016, including interim periods within those fiscal years. The Company adopted this guidance during the first quarter of 2017. As a result of adoption of this guidance, the Company elected to account for the forfeiture of stock-based compensation forfeitures as they occur. The adoption of this standard did not have a significant impact on the Company's 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 and related disclosures. As part of the Company's assessment work to-date, the Company formed an implementation work team, completed training of the new ASU's leasing guidance, and is developing a strategy for implementation.

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, and 2016-20, 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. The Company is currently evaluating the provisions of ASU 2014-09 and assessing the impact, if any, it may have on its financial statements and related disclosures. As part of the Company's assessment work to-date, the Company formed an implementation work team, completed training of the new ASU's revenue recognition model, and is developing a strategy for implementation.

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

Note 3—Acquisitions

Proposed July 2017 Acquisition

On March 24, 2017, the Company entered into a definitive agreement to acquire an unaffiliated oil and gas company's interests in approximately 12,500 net acres of leasehold, and related producing and non-producing properties located in the DJ Basin of Colorado, along with various other related rights, permits, contracts, equipment, rights of way, gathering systems and other assets (the "Proposed July 2017 Acquisition"). Upon closing the seller will receive total consideration of $84.0 million in cash, subject to customary purchase price adjustments. The effective date for the Proposed July 2017 Acquisition is July 1, 2017, with purchase price adjustments calculated as of the closing date, which is scheduled to occur in July 2017. The acquisition would provide new development opportunities in the DJ Basin. The Company also made an $8.4 million deposit in March 2017 in conjunction with Proposed July 2017 Acquisition, which has been reflected in the March 31, 2017 consolidated balance sheet within the cash held in escrow line item.

November 2016 Acquisition

On November 22, 2016, the Company acquired an unaffiliated oil and gas company's interest in approximately 9,200 net acres of leaseholds located in the DJ Basin for approximately $120.0 million, including customary closing adjustments (the "November 2016 Acquisition"). The Company also made a $41.1 million deposit in November 2016 in conjunction with November 2016 Acquisition, which has been reflected in the December 31, 2016 consolidated balance sheets within the cash held in escrow line item. The deposit was made for two additional closings of leaseholds located in the DJ Basin. The first closing occurred in January 2017 and added approximately 5,300 net acres. The second closing is expected to occur in July 2017 and will add approximately 800 net acres.

October 2016 Acquisition

On October 3, 2016, the Company acquired an unaffiliated oil and gas company's interests in approximately 6,400 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 $405.3 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 Company incurred $2.6 million of transaction costs related to the acquisition. These transaction costs were recorded in the consolidated statements of operations within the acquisition transaction expenses line item in the third and fourth quarter of 2016. No transaction costs related to the acquisition were incurred for the three months ended March 31, 2017 and 2016.

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. In February 2017, 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	**October 3, 2016**
Consideration given	
Cash	$ 405,335
Total consideration given	$ 405,335
Allocation of Purchase Price	
Proved oil and gas properties	$ 252,522
Unproved oil and gas properties	109,800
Total fair value of oil and gas properties acquired	$ 362,322
Goodwill [(1)]	$ 54,220
Working capital	(7,185)
Asset retirement obligations	(4,022)
Fair value of net assets acquired	$ 405,335
Working capital acquired was estimated as follows:	
Accounts receivable	$ 955
Revenue payable	(3,012)
Production taxes payable	(4,244)
Accrued liabilities	(884)
Total working capital	$ (7,185)

(1) Goodwill is primarily attributable to a decrease in commodity prices from the time the acquisition was negotiated to commodity prices on October 3, 2016 and the operational and financial synergies expected to be realized from the acquisition. Goodwill recognized as a result of the Bayswater Acquisition is not deductible for income tax purposes.

August 2016 Acquisition

On August 23, 2016, the Company acquired an unaffiliated oil and gas company's interests in approximately 1,400 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 $17.5 million in cash. The effective date for the acquisition was August 31, 2016, with purchase price adjustments calculated as of the closing date of 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 Company incurred $0.1 million of transaction costs related to the acquisition. These transaction costs were recorded in the consolidated statements of operations within the acquisition transaction expenses line item in the third quarter of 2016. No transaction costs related to the acquisition were incurred for the three months ended March 31, 2017 and 2016.

The acquisition was 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. In March 2017, 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	**August 23, 2016**
Consideration given	
Cash	$ 17,504
Total consideration given	$ 17,504
Allocation of Purchase Price	
Proved oil and gas properties	$ 12,362
Unproved oil and gas properties	8,566
Total fair value of oil and gas properties acquired	$ 20,928
Working capital	$ (9)
Asset retirement obligations	(3,415)
Fair value of net assets acquired	$ 17,504
Working capital acquired was estimated as follows:	
Production taxes payable	(9)
Total working capital	$ (9)

Pro Forma Financial Information (Unaudited)

For the three months ended March 31, 2016, the following pro forma financial information represents the combined results for the Company and the properties acquired in October 2016 as if the acquisition and related financing had occurred on January 1, 2016. The October 2016 Acquisition was included in the historical results of the Company for the three months ended March 31, 2017, therefore no pro forma financial information is presented for this period. For purposes of the pro forma financial information, it was assumed that the October 2016 Acquisition was funded through the issuance of $260.3 million in convertible preferred securities and borrowings under the revolving credit facility. The pro forma information includes the effects of adjustments for depletion, depreciation, amortization and accretion expense of $5.4 million for the three months ended March 31, 2016. The pro forma information includes the effects of adjustments for the incremental interest expense on acquisition financing of $1.1 million for the three months ended March 31, 2016. No pro forma adjustments were made for the effect of income taxes for the three months ended March 31, 2016 as the acquisitions occurred before the Corporate Reorganization. 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. Net loss per share is not applicable for the period prior to the Corporate Reorganization.

	For the Three Months Ended March 31, 2016
Revenues	$ 55,658
Operating expenses	$ 80,905
Net loss	$ (43,952)

Note 4—Long-Term Debt

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

	March 31, 2017	December 31, 2016
Credit facility due November 29, 2018	$ —	$ —
Senior Notes due July 15, 2021	550,000	550,000
Unamortized debt issuance costs on Senior Notes	(11,316)	(11,859)
Total long-term debt	538,684	538,141
Less: current portion of long-term debt	—	—
Total long-term debt, net of current portion	$ 538,684	$ 538,141

Credit Facility

The Company has commitments of $1.0 billion on its credit facility with a syndicate of banks, which is subject to a borrowing base. As of March 31, 2017, the credit facility was subject to a borrowing base of $475.0 million. The credit facility matures on November 29, 2018. As of each of March 31, 2017 and December 31, 2016, the Company had no outstanding borrowings. As of each of March 31, 2017 and December 31, 2016, the Company had standby letters of credit of $0.6 million. At March 31, 2017, the undrawn balance under the credit facility was $475.0 million. As of March 31, 2017 and the date of this filing, the Company has no balance outstanding under the credit facility. In May 2017, the Company amended its credit facility and issued a $20.0 million letter of credit, with the Company's oil marketer named as the beneficiary thereof.

Redetermination of the borrowing base occurs semiannually 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. In addition, the Company has exercised its right for a redetermination of the borrowing base on August 1, 2017.

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 below. 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 entering into hedges 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 availability under our revolving credit facility and unrestricted cash and excludes derivative assets) to our consolidated current liabilities (excludes obligations under our revolving credit facility, senior notes and certain derivative liabilities), 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 depletion, depreciation, 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 and including 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 March 31, 2017, and through the filing of this report.

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.

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 $537.2 million after deducting discounts and fees.

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 "Guarantors"). 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.

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 governing the Senior Notes (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 March 31, 2017, and through the filing of this report.

Debt Issuance Costs

As of March 31, 2017, the Company had debt issuance costs, net of accumulated amortization, of $1.9 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 March 31, 2017, the Company had debt issuance costs, net of accumulated amortization, of $11.3 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. Debt issuance costs include origination, legal, engineering and other fees incurred in connection with the Company's credit facility and Senior Notes. For the three months ended March 31, 2017 and 2016, the Company recorded amortization expense related to debt issuance costs of $0.9 million and $0.9 million, respectively.

Debt Discount Costs on Second Lien Notes

For the three months ended March 31, 2016, the Company recorded amortization expense related to the debt discount on its Second Lien Notes of $0.3 million. The Company recorded no amortization expense related to the debt discount on its Second Lien Notes for the three months ended March 31, 2017. For additional information regarding debt discount costs on Second Lien Notes, see the Company's Annual Report.

Interest Incurred on Long-Term Debt

For the three months ended March 31, 2017 and 2016, the Company incurred interest expense on long-term debt of $11.3 million and $13.3 million, respectively. For the three months ended March 31, 2017 and 2016, the Company capitalized interest expense on long term debt of $2.5 million and $0.9 million, respectively, which has been reflected in the Company's financial statements.

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 March 31, 2017 are summarized below:

	2017	2018
NYMEX WTI[(1)] Crude Swaps:		
Notional volume (Bbl)	450,000	—
Weighted average fixed price ($/Bbl)	$ 45.56	$ —
NYMEX WTI[(1)] Crude Sold Calls:		
Notional volume (Bbl)	5,800,000	3,700,000
Weighted average sold call price ($/Bbl)	$ 55.93	$ 62.36
NYMEX WTI[(1)] Crude Sold Puts:		
Notional volume (Bbl)	5,425,000	3,300,000
Weighted average sold put price ($/Bbl)	$ 38.02	$ 40.18
NYMEX WTI[(1)] Crude Purchased Puts:		
Notional volume (Bbl)	5,800,000	3,600,000
Weighted average purchased put price ($/Bbl)	$ 47.61	$ 50.33
NYMEX HH[(2)] Natural Gas Swaps:		
Notional volume (MMBtu)	20,430,000	14,400,000
Weighted average fixed price ($/MMBtu)	$ 3.06	$ 3.11
NYMEX HH[(2)] Natural Gas Purchased Puts:		
Notional volume (MMBtu)	—	2,400,000
Weighted average purchased put price ($/MMBtu)		$ 3.00
NYMEX HH[(2)] Natural Gas Sold Calls:		
Notional volume (MMBtu)	—	2,400,000
Weighted average sold call price ($/MMBtu)		$ 3.15
CIG[(3)] Basis Gas Swaps:		
Notional volume (MMBtu)	10,090,000	2,250,000
Weighted average fixed basis price ($/MMBtu)	$ (0.35)	$ (0.29)

(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 consolidated balance sheets (in thousands):

	As of March 31, 2017				
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	$ 17,776	$ (17,776)	$ —	$ (4,951)	$ 774
Non-current assets	$ 16,205	$ (10,481)	$ 5,724	$ —	$ —
Current liabilities	$ (26,778)	$ 17,776	$ (9,002)	$ 4,951	$ (4,052)
Non-current liabilities	$ (10,481)	$ 10,481	$ —	$ —	$ —

	As of December 31, 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	$ 12,620	$ (12,620)	$ —	$ —	$ —
Non-current assets	$ 14,993	$ (14,993)	$ —	$ —	$ —
Current liabilities	$ (68,623)	$ 12,620	$ (56,003)	$ —	$ (62,741)
Non-current liabilities	$ (21,731)	$ 14,993	$ (6,738)	$ —	$ —

(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 consolidated balance sheets. 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 months ended March 31, 2017 and 2016 (in thousands). Commodity derivatives gain (loss) is included under other income (expense) in the consolidated statements of operations.

	For the Three Months Ended March 31,	
	2017	2016
Commodity derivatives gain (loss)	$ 50,422	$ (4,036)

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 local, state and federal laws and applicable lease terms. 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 period indicated (in thousands):

	For the Three Months Ended March 31, 2017
Balance beginning of period	$ 56,108
Liabilities incurred or acquired	1,157
Liabilities settled	(606)
Revisions in estimated cash flows	—
Accretion expense	1,467
Balance end of period	$ 58,126

Note 7—Fair Value Measurements

ASC 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 March 31, 2017 and December 31, 2016 by level within the fair value hierarchy (in thousands):

	Fair Value Measurements at March 31, 2017 Using			
	Level 1	Level 2	Level 3	Total
Financial Assets:				
Commodity derivative assets	$ —	$ 5,724	$ —	$ 5,724
Financial Liabilities:				
Commodity derivative liabilities	$ —	$ 9,002	$ —	$ 9,002

	Fair Value Measurements at December 31, 2016 Using			
	Level 1	Level 2	Level 3	Total
Financial Assets:				
Commodity derivative assets	$ —	$ —	$ —	$ —
Financial Liabilities:				
Commodity derivative liabilities	$ —	$ 62,741	$ —	$ 62,741

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 Senior Notes was derived from available market data. As such, the Company has classified the 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 March 31, 2017		At December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Senior Notes[(1)]	$ 538,684	$ 581,625	$ 538,141	$ 588,500

(1) The carrying amount of the Senior Notes includes unamortized debt issuance costs of $11.3 million and $11.9 million as of March 31, 2017 and December 31, 2016, respectively.

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 and goodwill. These assets and liabilities are not measured at fair value on a recurring basis, but are subject to fair value adjustments when facts and circumstances arise that indicate a need for remeasurement.

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 include 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 a market-based 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 March 31, 2017 and 2016 on proved oil and gas properties.

The Company applies the provisions of ASC 350, *Intangibles-Goodwill and Other*. Goodwill represents the excess of the purchase price over the estimated value of the net assets acquired in business combinations. The Company tests goodwill for impairment annually on September 30, or whenever other circumstances or events indicate that the carrying amount of goodwill may not be recoverable. The goodwill test is performed at the reporting unit level, which represents the Company's oil and gas operations in the DJ Basin. If indicators of impairment are determined to exist, an impairment charge is recognized if the carrying value of goodwill exceeds its implied fair value. The Company utilizes the market approach to determine the fair value of the reporting unit. Any sharp prolonged decreases in the prices of oil and natural gas as well as continued declines in the quoted market price of the Company's common shares could change the estimates of the fair value of the reporting unit and could result in an impairment charge. The Company performed a qualitative assessment as of March 31, 2017, which concluded the fair value of the reporting unit was more-likely-than-not greater than its carrying amount.

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, development costs 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—Income Taxes

The Company computes an estimated annual effective rate each quarter based on the current and forecasted operating results. The income tax expense or benefit associated with the interim period is computed using the most recent estimated annual effective rate applied to the year-to-date ordinary income or loss, plus the tax effect of any significant discrete or infrequently occurring times recorded during the interim period. The computation of the annual estimated effective tax rate at each interim period requires certain estimates and significant judgement including, but not limited to, the expected operating income for the year, projections of the proportion of income earned and taxed in various jurisdictions, permanent and temporary differences and the likelihood of recovering deferred tax assets generated in the current year. The accounting estimates used to compute the provision for income taxes may change as new events occur, more experience is obtained and additional information becomes known or as the tax environment changes.

The effective combined U.S. federal and state income tax rate as of March 31, 2017 was 37%. During the three months ended March 31, 2017, the Company recognized income tax expense of $5.1 million. The effective rate for the three months ended March 31, 2017 differs from the statutory U.S. federal income tax rate of 35% primarily due to state income taxes and estimated permanent differences. There were no significant discrete items recorded during the three months ended March 31, 2017. The Company's accounting predecessor was a limited liability company that was not subject to U.S. federal income tax during the first quarter of 2016.

Note 9—Unit and Stock-Based Compensation

Extraction Long Term Incentive Plan

In October 2016, the Company's board of directors 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. 20.2 million shares of common stock have been reserved for issuance pursuant to awards under the LTIP.

Stock Options

Expense on the stock options are recognized on a straight-line basis over the service period of the award less awards forfeited. The fair value of the stock options were measured at the grant date using the Black-Scholes valuation model. The Company utilizes the "simplified" method to estimate the expected term of the stock options granted as there is limited historical exercise data available in estimating the expected term of the stock options. Expected volatility is based on the volatility of the historical stock prices of the Company's peer group. The risk-free rates are based on the yields of U.S. Treasury instruments with comparable terms. A dividend yield and forfeiture rate of zero were assumed. Stock options granted under the LTIP vest ratably over three years and are exercisable immediately upon vesting through the tenth anniversary of the grant date. To fulfill options exercised, the Company will issue new shares.

The Company recorded $3.3 million of stock-based compensation costs related to the stock options for the three months ended March 31, 2017. These costs were included in the consolidated statements of operations within the general and administrative expenses line item. The Company did not record any stock-based compensation expense related to stock options for the three months ended March 31, 2016. As of March 31, 2017, there was $33.2 million of unrecognized compensation cost related to the stock options that is expected to be recognized over a weighted average period of 2.5 years.

The following table summarizes the stock option activity from January 1, 2017 through March 31, 2017 and provides information for stock options outstanding at the dates indicated.

	Number of Shares	Weighted Average Exercise Price
Non-vested Stock Options at January 1, 2017	4,500,000	$ 19.00
Granted	—	$ —
Forfeited	—	$ —
Vested	—	$ —
Non-vested Stock Options at March 31, 2017	4,500,000	$ 19.00

Restricted Stock Units

Restricted stock units granted under the LTIP ("RSUs") generally vest over either a one or three year service period, with 100% vesting in year one or 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 Extraction's common stock on the date of issuance. The Company assumed a forfeiture rate of zero as part of the grant date estimate of compensation cost.

The Company recorded $7.9 million of stock-based compensation costs related to RSUs for the three months ended March 31, 2017 and no stock-based compensation costs related to RSUs for the three months ended March 31, 2016. These costs were included in the consolidated statements of operations within the general and administrative expenses line item. As of March 31, 2017, there was $72.0 million of total unrecognized compensation cost related to the unvested RSUs granted to certain directors, officers and employees that is expected to be recognized over a weighted average period of 2.5 years.

The following table summarizes the RSU activity from January 1, 2017 through March 31, 2017 and provides information for RSUs outstanding at the dates indicated.

	Number of Shares	Weighted Average Grant Date Fair Value
Non-vested RSUs at January 1, 2017	3,237,500	$ 21.41
Granted	959,137	$ 16.84
Forfeited	—	$ —
Vested	—	$ —
Non-vested RSUs at March 31, 2017	4,196,637	$ 20.37

Incentive Restricted Stock Units

Officers of the Company contributed 2.7 million shares of common stock to Extraction Employee Incentive, LLC (“Employee Incentive”), which is owned solely by certain officers of the Company. Employee Incentive issued restricted stock units (“Incentive RSUs”) to certain employees. Incentive RSUs 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 Extraction’s common stock on the date of issuance. The Company assumed a forfeiture rate of zero as part of the grant date estimate of compensation cost. As the vesting of any Incentive RSUs will be satisfied with shares of common stock that are already issued and outstanding, the Incentive RSUs do not have any impact on the Company’s diluted earnings per share calculation.

The Company recorded $4.5 million of stock-based compensation costs related to Incentive RSUs for the three months ended March 31, 2017 and no stock-based compensation costs related to Incentive RSUs for the three months ended March 31, 2016. These costs were included in the consolidated statements of operations within the general and administrative expenses line item. As of March 31, 2017, there was $47.7 million of total unrecognized compensation cost related to the unvested Incentive RSUs granted to certain employees that is expected to be recognized over a weighted average period of 2.6 years.

The following table summarizes the Incentive RSU activity from January 1, 2017 through March 31, 2017 and provides information for Incentive RSUs outstanding at the dates indicated.

	Number of Shares	Weighted Average Grant Date Fair Value
Non-vested Incentive RSUs at January 1, 2017	2,714,368	$ 20.45
Granted	—	$ —
Forfeited	(45,200)	$ 20.45
Vested	—	$ —
Non-vested Incentive RSUs at March 31, 2017	2,669,168	$ 20.45

Unit-Based Compensation

The Company recorded $1.4 million of unit-based compensation costs related to restricted unit awards for the three months ended March 31, 2016. As of March 31, 2017, there was no unrecognized compensation costs related to these restricted unit awards. For additional disclosure regarding these restricted unit awards, see the Company’s Annual Report.

Note 10—Earnings (Loss) Per Share

Basic earnings per share ("EPS") includes no dilution and is computed by dividing net income (loss) by the weighted average number of shares outstanding during the period. Diluted EPS reflects the potential dilution of securities that could share in the earnings of the Company.

The Company uses the "if-converted" method to determine potential dilutive effects of the Company's outstanding Series A Preferred Stock (the "Series A Preferred Stock") and the treasury method to determine the potential dilutive effects of outstanding restricted stock awards and stock options. The basic weighted average shares outstanding calculation is based on the actual days in which the shares were outstanding for the three months ended March 31, 2017. EPS information is not applicable for the three months ended March 31, 2016.

The components of basic and diluted EPS were as follows (in thousands, except per share data):

	For the Three Months Ended March 31, 2017
Basic and Diluted Earnings Per Share	
Net Income	$ 8,716
Less: Adjustment to reflect Series A Preferred Stock dividend	(2,721)
Less: Adjustment to reflect accretion of Series A Preferred Stock discount	(1,296)
Adjusted net income available to common shareholders, basic and diluted	$ 4,699
Denominator:	
Weighted average common shares outstanding, basic and diluted [(1)]	171,835
Earnings Per Common Share	
Basic and diluted	$ 0.03

(1) For the three months ended March 31, 2017, the diluted EPS calculation excludes the dilutive effect of 4,500,000 common shares for stock options that were out-of-the-money, the anti-dilutive effect of 4,196,637 RSUs and the anti-dilutive effect of 11,472,445 common shares issuable for Series A Preferred Stock under the if-converted method.

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 August 31, 2019 and October 31, 2017, respectively. Total rental commitments under non-cancelable leases for office space were $20.5 million at March 31, 2017. The future minimum lease payments under these non-cancelable leases are as follows: $1.9 million in 2017, $2.5 million in 2018, $2.4 million in 2019, $2.1 million in 2020, $2.1 million in 2021 and $9.5 million thereafter. Rent expense was $0.6 million and $0.3 million for the three months ended March 31, 2017 and 2016, respectively.

On June 4, 2015, the Company subleased the remaining term of one of its Denver office leases that expires February 29, 2020. The sublease will decrease the Company's future lease payments by $0.7 million.

Drilling Rigs

As of March 31, 2017, the Company was subject to commitments on four drilling rigs. In the event of early termination of these contracts, the Company would be obligated to pay an aggregate amount of approximately $8.4 million as of March 31, 2017, as required under the terms of the contracts. The fourth rig is expected to be placed in service during the third quarter of 2017 and will replace a rig currently under contract.

Delivery Commitments

As of March 31, 2017, the Company's oil marketer was subject to a firm transportation agreement that commenced in November 2016 and has a ten-year term with a monthly minimum delivery commitment of 45,000 Bbl/d in year one, 55,800 Bbl/d in year two, 61,800 Bbl/d in years three through seven and 58,000 Bbl/d in years eight through ten. We amended our agreement with our oil marketer that requires us to sell all of our crude oil from an area of mutual interest in exchange for a make-whole provision that allows us to satisfy any minimum volume commitment deficiencies incurred by our oil marketer with future barrels of crude oil in excess of their minimum volume commitment through October 31, 2018. The Company evaluates its contracts for loss contingencies and accrues for such losses, if the loss can be reasonably estimated and deemed probable. The Company also has one long-term crude oil gathering commitment. It has a term of ten years for an average of 9,167 Bbl/d in year one, 17,967 Bbl/d in year two, 18,800 Bbl/d for years three through five and 10,000 Bbl/d for years six through ten. The aggregate amount of estimated payments under these agreements is $1.0 billion.

In collaboration with several other producers and DCP Midstream Partners, LP ("DCP") on December 15, 2016, the Company agreed to participate in the expansion of natural gas gathering and processing capacity in the DJ Basin. The plan includes a new processing plant as well as the expansion of a related gathering system, both currently expected to be completed by late 2018, although the start-up date is undetermined at this time. The Company's share of the commitment will require 51.5 MMcf per day to be delivered after the plant in-service date for a period of seven years thereafter. The Company may be required to pay a shortfall fee for any volumes under the 51.5 MMcf per day commitment. This contractual obligation can be reduced by the Company's proportionate share of the collective volumes delivered to the plant by other third party incremental volumes available to DCP at the new facility that are in excess of the total commitment. The Company is also required for the first three years of the contract to guarantee a certain target profit margin on these volumes sold. Under its current drilling plans, the Company expects to meet the volume commitment.

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.

Acquisition of Undeveloped Leasehold Acreage

As of March 31, 2017, the Company is obligated under an agreement with an unrelated third party to pay approximately $25.0 million in the remainder of 2017 for the acquisition of undeveloped leasehold acreage.

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 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 this filing.

The Company is currently in discussions with the Colorado Department of Public Health and Environment ("CDPHE") regarding a Compliance Advisory issued to the Company in July 2015, which alleged air quality violations at three Company facilities regarding leakages of volatile organic compounds from storage tanks, all of which were promptly addressed. On August 12, 2016, the CDPHE expanded its investigation to several additional Company facilities and, on December 7, 2016 indicated to the Company that it is further expanding its investigation to the Company's other facilities in Colorado and intends to seek a field-wide administrative settlement of these issues. At this time, the Company cannot predict the outcome of this matter at this time or the remediation or the compliance costs that this matter may impose on the Company.

Note 12—Related Party Transactions

Office Lease with Related Affiliate

In April 2016, the Company subleased office space to Star Peak Capital, LLC, of which a member of the board of directors is an owner, for $1,400 per month. The sublease commenced on May 1, 2016 and expires on February 28, 2020.

Senior Notes

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

Series A Preferred Stock

As of the initial issuance, stockholders of the Company held all of the $185.3 million of Series A Preferred Stock.

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

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q ("Quarterly Report") contains "forward-looking statements." All statements, other than statements of historical facts, included or incorporated by reference 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. For such statements, we claim the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. 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, natural gas and NGL 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, natural gas and NGL that are ultimately recovered.

In addition to the other information and risk factors set forth in this Quarterly Report, you should carefully consider the risk factors and other cautionary statements described under the heading “Risk Factors” included in our Annual Report on Form 10-K for the year ended December 31, 2016 (our “Annual Report”) and in our other filings with Securities Exchange Commission, 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 our Annual Report.

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. 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.

Management’s Discussion and Analysis of Financial Condition and Results of Operations (“MD&A”) is intended to provide the reader of the financial statements with a narrative from the perspective of management on the financial condition, results of operations, liquidity and certain other factors that may affect the Company’s operating results. MD&A should be read in conjunction with the Condensed Consolidated Financial Statements and related Notes included in Part I, Item 1 of this Quarterly Report. The following information updates the discussion of the Company’s financial condition provided in its Annual Report and analyzes the changes in the results of operations between the three months ended March 31, 2017 and 2016.

EXECUTIVE SUMMARY

We are an independent oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves in the Rocky Mountain region, primarily in the Wattenberg Field of the DJ Basin. 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 some of the most productive areas of what we consider to be the core of the DJ Basin. 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 Results

For the three months ended March 31, 2017, oil, natural gas and NGL sales, coupled with the impact of settled derivatives, increased to $80.6 million as compared to $72.6 million in the same period in 2016 due to an increase in sales volumes of 751 MBoe partially offset by a decrease of $5.38 in realized price per BOE, including settled derivatives.

For the three months ended March 31, 2017, we had net income of $8.7 million as compared to net loss of $45.5 million for the three months ended March 31, 2016. The increase to net income was primarily driven by an increase in commodity derivatives and sales revenues of $54.5 million and $44.5 million, respectively. These increases to net income were offset by an increase in operating expenses of $44.0 million primarily related to the increased sales volumes.

Adjusted EBITDAX was $42.4 million for the three months ended March 31, 2017, as compared to $50.4 million in the same period in 2016, reflecting a 16% decrease. 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 Results

During the three months ended March 31, 2017, our aggregate drilling, completion, leasehold and midstream capital expenditures totaled $233.1 million, excluding acquisitions. We reached total depth on 47 gross (38 net) wells with an average lateral length of approximately 7,900 feet and completed 54 gross (47 net) wells with an average lateral length of approximately 7,000 feet. We turned to sales 26 gross (25 net) wells with an average lateral length of approximately 7,000 feet. Due to the completion of higher working interest pads during the first half of 2017, we expect our net drilling and completion capital expenditures to be weighted slightly towards the first half of 2017.

Towards the end of the first quarter of 2017, we turned to sales 24 gross (23 net) wells on two pads as part of our Windsor development project, which included 16 wells targeting the Niobrara formation and 8 targeting the Codell. The 16 Niobrara wells were all completed utilizing our enhanced completion well design.

Recent Developments

Amended Commodity Marketing Agreement

As of March 31, 2017, our oil marketer was subject to a firm transportation agreement that commenced in November 2016 and has a ten-year term with a monthly minimum delivery commitment of 45,000 Bbl/d in year one, 55,800 Bbl/d in year two, 61,800 Bbl/d in years three through seven and 58,000 Bbl/d in years eight through ten. We amended our agreement with our oil marketer that requires us to sell all of our crude oil from an area of mutual interest in exchange for a make-whole provision that allows us to satisfy any minimum volume commitment deficiencies incurred by our oil marketer with future barrels of crude oil in excess of their minimum volume commitment through October 31, 2018. We evaluate our contracts for loss contingencies and accrues for such losses, if the loss can be reasonably estimated and deemed probable.

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 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 March 31, 2017, our revenues were derived 58% from oil sales, 22% from natural gas sales and 20% from NGL sales. For the three months ended March 31, 2016, our revenues were derived 76% from oil sales, 14% from natural gas sales and 10% 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 periods indicated:

	For the Three Months Ended March 31,	
	2017	2016
Oil (MBbl)	1,211	1,259
Natural gas (MMcf)	6,359	3,520
NGL (MBbl)	734	408
Total (MBoe)	3,005	2,254
Average net sales (BOE/d)	33,383	24,766

As reservoir pressure declines, 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. Please read "Risks Related to the Oil, Natural Gas and NGL Industry and Our Business" in Item 1A. of our Annual Report for a further description of the risks that affect us.

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 March 31, 2017, 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 into 2017 are due to a combination of factors including increased U.S. supply, global economic concerns and geopolitical risks. 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 DJ Basin, 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. The price we receive for our natural gas produced in the DJ Basin is based on CIG prices, adjusted for certain deductions.

Our price for NGL produced in the DJ Basin 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. 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.

	For the Three Months Ended March 31,	
	2017	**2016**
Oil		
NYMEX WTI High ($/Bbl)	$ 54.45	$ 41.45
NYMEX WTI Low ($/Bbl)	$ 47.34	$ 26.21
NYMEX WTI Average ($/Bbl)	$ 51.78	$ 33.63
Average Realized Price ($/Bbl)	$ 43.05	$ 27.08
Average Realized Price, with derivative settlements ($/Bbl)	$ 36.42	$ 46.30
Average Realized Price as a % of Average NYMEX WTI	83.1 %	80.5 %
Differential ($/Bbl) to Average NYMEX WTI	$ (8.74)	$ (6.55)
Natural Gas		
NYMEX Henry Hub High ($/MMBtu)	$ 3.42	$ 2.47
NYMEX Henry Hub Low ($/MMBtu)	$ 2.56	$ 1.64
NYMEX Henry Hub Average ($/MMBtu)	$ 3.06	$ 1.98
Average Realized Price ($/Mcf)	$ 3.13	$ 1.88
Average Realized Price, with derivative settlements ($/Mcf)	$ 2.97	$ 2.80
Average Realized Price as a % of Average NYMEX Henry Hub(1)	92.9 %	86.1 %
Differential ($/Mcf) to Average NYMEX Henry Hub(1)	$ (0.24)	$ (0.30)
NGL		
Average Realized Price ($/Bbl)	$ 24.00	$ 10.88
Average Realized Price as a % of Average NYMEX WTI	46.3 %	32.3 %

(1) Based on the difference between our average realized price and the NYMEX Henry Hub Average as converted into Mcf using a conversion factor of 1.1 to 1.

Derivative Arrangements

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, from time to time we enter into derivative arrangements for our oil and natural gas production. By removing a significant portion of price volatility associated with our oil and natural gas production, we believe we will mitigate, but not eliminate, the potential negative effects of reductions in oil and natural gas prices on our cash flow from operations for those periods. However, in a portion of our current positions, our hedging activity may also reduce our ability to benefit from increases in oil and natural gas prices. We will sustain losses to the extent our derivatives contract prices are lower than market prices and, conversely, we will realize gains to the extent our derivatives contract prices are higher than market prices. In certain circumstances, where we have unrealized gains in our derivative portfolio, we may choose to restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of our existing positions. See "—Quantitative and Qualitative Disclosure About Market Risk—Commodity Price Risk" for information regarding our exposure to market risk, including the effects of changes in commodity prices, and our commodity derivative contracts.

We will continue to use commodity derivative instruments to hedge our price risk in the future. Our hedging strategy and future hedging transactions will be determined at our discretion and may be different than what we have done on a historical basis. As a result of recent volatility in the price of oil and natural gas, we have relied on a variety of hedging strategies and instruments to hedge our future price risk. We have utilized swaps, put options and call options, which in some instances require the payment of a premium, to reduce the effect of price changes on a portion of our future oil and natural gas production. We expect to continue to use a variety of hedging strategies and instruments for the foreseeable future.

A swap has an established fixed price. When the settlement price is below the fixed price, the counterparty pays us 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, we pay our 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 our purchased put options have deferred premiums. For the deferred premium puts, we agreed 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.

We combine swaps, purchased put options, sold put options and sold call options in order to achieve various hedging strategies. Some examples of our 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. We have historically relied on commodity derivative contracts to mitigate our exposure to lower commodity prices.

We have historically been able to hedge our oil and natural gas production at prices that are significantly higher than current strip prices. However, in the current commodity price environment, our ability to enter into comparable derivative arrangements at favorable prices may be limited, and, we are not obligated to hedge a specific portion of our oil or natural gas production. The following summarizes our derivative positions related to crude oil and natural gas sales in effect as of March 31, 2017:

	2017	2018
NYMEX WTI(1) Crude Swaps:		
Notional volume (Bbl)	450,000	—
Weighted average fixed price ($/Bbl)	$ 45.56	$ —
NYMEX WTI(1) Crude Sold Calls:		
Notional volume (Bbl)	5,800,000	3,700,000
Weighted average sold call price ($/Bbl)	$ 55.93	$ 62.36
NYMEX WTI(1) Crude Sold Puts:		
Notional volume (Bbl)	5,425,000	3,300,000
Weighted average sold put price ($/Bbl)	$ 38.02	$ 40.18
NYMEX WTI(1) Crude Purchased Puts:		
Notional volume (Bbl)	5,800,000	3,600,000
Weighted average purchased put price ($/Bbl)	$ 47.61	$ 50.33
NYMEX HH(2) Natural Gas Swaps:		
Notional volume (MMBtu)	20,430,000	14,400,000
Weighted average fixed price ($/MMBtu)	$ 3.06	$ 3.11
NYMEX HH(2) Natural Gas Purchased Puts:		
Notional volume (MMBtu)	—	2,400,000
Weighted average purchased put price ($/MMBtu)		$ 3.00
NYMEX HH(2) Natural Gas Sold Calls:		
Notional volume (MMBtu)	—	2,400,000
Weighted average sold call price ($/MMBtu)		$ 3.15
CIG(3) Basis Gas Swaps:		
Notional volume (MMBtu)	10,090,000	2,250,000
Weighted average fixed basis price ($/MMBtu)	$ (0.35)	$ (0.29)

(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 table summarizes our historical derivative positions and the settlement amounts for each of the periods indicated.

	For the Three Months Ended March 31, 2017	For the Three Months Ended March 31, 2016
NYMEX HH[(1)] Natural Gas Swaps:		
Notional volume (MMBtu)	4,990,000	2,965,080
Weighted average fixed price ($/MMBtu)	$ 3.05	$ 3.18
CIG[(3)] Basis Gas Swaps:		
Notional volume (MMBtu)	990,000	—
Weighted average fixed basis price ($/MMBtu)	$ (0.19)	$ —
NYMEX WTI[(2)] Crude Swaps:		
Notional volume (Bbl)	1,050,000	330,045
Weighted average fixed price ($/Bbl)	$ 43.11	$ 47.53
NYMEX WTI[(2)] Crude Sold Puts:		
Notional volume (Bbl)	595,000	—
Weighted average strike price ($/Bbl)	$ 35.24	$ —
NYMEX WTI[(2)] Crude Purchased Puts:		
Notional volume (Bbl)	70,000	1,065,135
Weighted average strike price ($/Bbl)	$ 50.00	$ 55.33
NYMEX WTI[(2)] Crude Sold Calls:		
Notional volume (Bbl)	70,000	985,090
Weighted average strike price ($/Bbl)	$ 57.14	$ 64.67
NYMEX WTI[(2)] Crude Purchased Calls:		
Notional volume (Bbl)	—	110,000
Weighted average strike price ($/Bbl)	$ —	$ 69.55
Total Amounts Received/(Paid) from Settlement (in thousands)	**$ (9,041)**	**$ 30,502**
Cash provided by (used in) changes in Accounts Receivable and Accounts Payable related to Commodity Derivatives	$ (88)	$ (1,430)
Cash Settlements on Commodity Derivatives per Consolidated Statements of Cash Flows	**$ (9,129)**	**$ 29,072**

(1) NYMEX HH refers to the Henry Hub natural gas price on the New York Mercantile Exchange
(2) NYMEX WTI refers to West Texas Intermediate crude oil 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.

Lease Operating Expenses

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

Capital Expenditures

For the three months ended March 31, 2017, we incurred approximately $209.2 million in capital expenditures in connection with the drilling of 47 gross (38 net) wells with an average lateral length of approximately 7,900 feet and completing 54 gross (47 net) wells with an average lateral length of approximately 7,000 feet. We turned to sales 26 gross (25 net) wells with an average lateral length of approximately 7,000 feet. In addition, we incurred approximately $21.1 million of leaseholds and surface acreage additions and approximately $2.8 million of midstream and infrastructure additions, excluding amounts paid for acquisitions.

Our 2017 capital budget is approximately $795 million to $935 million, substantially all of which we intend to allocate to the DJ Basin. We intend to allocate approximately $675 million to $775 million of our 2017 capital budget to the drilling of 185 to 190 gross operated wells and the completion of 190 to 195 gross operated wells, approximately $60 to $80 million of non-operated drilling and completion, and approximately $60 million to $80 million to undeveloped leasehold acquisitions, midstream, and other capital expenditures. We are currently running a three rig program and plan to use a fourth rig on a spot basis to fill in gaps in the drilling program. Our capital budget excludes any amounts that were or may be paid for potential acquisitions.

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 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 depletion, depreciation, 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 and stock-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 (in thousands).

	For the Three Months Ended March 31, 2017	2016
Reconciliation of Adjusted EBITDAX:		
Net income (loss)	$ 8,716	$ (45,520)
Add back:		
Depletion, depreciation, amortization and accretion	50,653	45,308
Impairment of long lived assets	675	446
Exploration expenses	10,812	2,831
Rig termination fee	—	891
Loss on sale of property and equipment	451	—
Acquisition transaction expenses	68	—
(Gain) loss on commodity derivatives	(50,422)	4,036
Settlements on commodity derivative instruments	(9,041)	30,502
Premiums paid for derivatives that settled during the period	—	(3,060)
Unit and stock-based compensation expense	15,745	1,368
Amortization of debt discount and debt issuance costs	845	1,198
Interest expense	8,815	12,370
Income tax expense	5,130	—
Adjusted EBITDAX	$ 42,447	$ 50,370

Items Affecting the Comparability of Our Financial Results

Our historical results of operations for the periods presented may not be comparable, either to each other or to our future results of operations, for the reasons described below:

- On October 3, 2016, we acquired additional oil and gas properties primarily located in the Wattenberg Field located primarily around our existing Greeley and Windsor areas. The October 2016 Acquisition consisted of working interest in approximately 6,400 net acres and 31 gross (19 net) drilled but uncompleted wells, as of the date of acquisition. The October 2016 Acquisition provided net daily production of approximately 6,900 BOE/d during the fourth quarter 2016.
- As a result of the IPO, we expect to incur additional general and administrative expenses related to being a public company, including Exchange Act reporting expenses; expenses associated with Sarbanes-Oxley compliance; expenses associated with listing on the NASDAQ Global Select Market; incremental independent auditor fees; incremental legal fees; investor relations expenses; registrar and transfer agent fees; incremental director and officer liability insurance costs; and directors compensation.
- Prior to the Corporate Reorganization, we were not subject to federal or state income taxes. Accordingly, the financial data attributable to us prior to such corporate reorganization contain no provision for federal or state income taxes because the tax liability with respect to Holdings' taxable income was passed through to our members. Beginning October 12, 2016, we began to 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.

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 March 31, 2017	For the Three Months Ended March 31, 2016
	(Unaudited)	
Revenues:		
Oil sales	$ 52,128	$ 34,088
Natural gas sales	19,897	6,606
NGL sales	17,614	4,438
Total Revenues	89,639	45,132
Operating Expenses:		
Lease operating expenses	22,323	11,970
Production taxes	6,453	4,490
Exploration expenses	10,812	2,831
Depletion, depreciation, amortization and accretion	50,653	45,308
Impairment of long lived assets	675	446
Other operating expenses	451	891
Acquisition transaction expenses	68	—
General and administrative expenses	25,688	7,140
Total Operating Expenses	117,123	73,076
Operating Loss	(27,484)	(27,944)
Other Income (Expense):		
Commodity derivatives gain (loss)	50,422	(4,036)
Interest expense	(9,660)	(13,568)
Other income	568	28
Total Other Income (Expense)	41,330	(17,576)
Net Income (Loss) Before Income Taxes	13,846	(45,520)
Income Tax Expense	5,130	—
Net Income (Loss)	$ 8,716	$ (45,520)

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

	For the Three Months Ended March 31, 2017	2016
Sales (MBoe)[1]:	3,005	2,254
Oil sales (MBbl)	1,211	1,259
Natural gas sales (MMcf)	6,359	3,520
NGL sales (MBbl)	734	408
Sales (BOE/d)[1]:	33,383	24,766
Oil sales (Bbl/d)	13,454	13,840
Natural gas sales (Mcf/d)	70,651	38,681
NGL sales (Bbl/d)	8,154	4,479
Average sales prices[2]:		
Oil sales (per Bbl)	$ 43.05	$ 27.08
Oil sales with derivative settlements (per Bbl)	36.42	46.30
Natural gas sales (per Mcf)	3.13	1.88
Natural gas sales with derivative settlements (per Mcf)	2.97	2.80
NGL sales (per Bbl)	24.00	10.88
Average price per BOE	29.83	20.03
Average price per BOE with derivative settlements	26.82	32.20
Expense per BOE:		
Lease operating expenses	$ 7.43	$ 5.31
Operating expenses	4.01	3.49
Transportation and gathering	3.42	1.82
Production taxes	2.15	1.99
Exploration expenses	3.60	1.26
Depletion, depreciation, amortization and accretion	16.86	20.10
Impairment of long lived assets	0.22	0.20
Other operating expenses	0.15	0.40
Acquisition transaction expenses	0.02	—
General and administrative expenses	8.55	3.17
Cash general and administrative expenses	3.31	2.56
Unit and stock-based compensation	5.24	0.61
Total operating expenses per BOE	38.98	32.43

(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 settlements for commodity derivatives and amortization of premiums paid or received on options that settled during the period.

Three Months Ended March 31, 2017 Compared to Three Months Ended March 31, 2016

Oil sales revenues. Crude oil sales revenues increased by $18.0 million to $52.1 million for the three months ended March 31, 2017 as compared to crude oil sales of $34.1 million for the three months ended March 31, 2016. An increase in crude oil prices contributed a $19.3 million positive impact while a decrease in sales volumes between these periods contributed a $1.3 million negative impact.

For the three months ended March 31, 2017, our crude oil sales averaged 13.5 MBbl/d. Our crude oil sales volume decreased 4% to 1,211 MBbl for the three months ended March 31, 2017 compared to 1,259 MBbl for the three months ended March 31, 2016. The volume decrease is primarily due to the natural decline of our existing properties, partially offset by an increase in production from the completion of 122 gross wells from April 1, 2016 to March 31, 2017.

The average price we realized on the sale of crude oil was $43.05 per Bbl for the three months ended March 31, 2017 compared to $27.07 per Bbl for the three months ended March 31, 2016.

Natural gas sales revenues. Natural gas revenues increased by $13.3 million to $19.9 million for the three months ended March 31, 2017 as compared to natural gas revenues of $6.6 million for the three months ended March 31, 2016. An increase in sales volumes between these periods contributed a $5.3 million positive impact, while an increase in natural gas prices contributed a $8.0 million positive impact due to increasing natural gas prices.

For the three months ended March 31, 2017, our natural gas sales averaged 70.7 MMcf/d. Natural gas sales volumes increased by 81% to 6,359 MMcf for the three months ended March 31, 2017 as compared to 3,520 MMcf for the three months ended March 31, 2016. The volume increase is primarily due to the completion of 122 gross wells from April 1, 2016 to March 31, 2017, partially offset by the natural decline on existing producing properties.

The average price we realized on the sale of our natural gas was $3.13 per Mcf for the three months ended March 31, 2017 compared to $1.88 per Mcf for the three months ended March 31, 2016.

NGL sales revenues. NGL revenues increased by $13.2 million to $17.6 million for the three months ended March 31, 2017 as compared to NGL revenues of $4.4 million for the three months ended March 31, 2016. An increase in sales volumes between these periods contributed a $3.6 million positive impact, while an increase in price contributed a $9.6 million positive impact.

For the three months ended March 31, 2017, our NGL sales averaged 8.2 MBbl/d. NGL sales volumes increased by 80% to 734 MBbl for the three months ended March 31, 2017 as compared to 408 MBbl for the three months ended March 31, 2016. The volume increase is primarily due to the completion of 122 gross wells from April 1, 2016 to March 31, 2017, partially offset by the natural decline on existing producing properties. Our NGL sales are directly associated with our natural gas sales because our natural gas volumes are processed by third parties for both residue natural gas sales and NGL sales.

The average price we realized on the sale of our NGL was $24.00 per Bbl for the three months ended March 31, 2017 compared to $10.88 per Bbl for the three months ended March 31, 2016.

Lease operating expenses. Our LOE increased by $10.3 million to $22.3 million for the three months ended March 31, 2017, from $12.0 million for the three months ended March 31, 2016.

On a per unit basis, LOE increased from $5.31 per BOE sold for the three months ended March 31, 2016 to $7.43 per BOE sold for the three months ended March 31, 2017. The increase in LOE was comprised of an increase in transportation and gathering ("T&G") expense of $6.2 million for the three months ended March 31, 2017 compared to the three months ended March 31, 2016 and an increase in operating expenses of $4.1 million for the three months ended March 31, 2017 compared to the three months ended March 31, 2016. The increase in LOE was primarily the result of an increase in residue natural gas sales and NGL sales and related T&G fees as a result of our increased exposure to fee-type gas transportation contracts versus percent of proceeds gas transportation contracts.

Production taxes. Our production taxes increased by $2.0 million to $6.5 million for the three months ended March 31, 2017 as compared to $4.5 million for the three months ended March 31, 2016. The increase is primarily attributable to increased revenue as production taxes are calculated as a percentage of sales revenue. Production taxes as a percentage of sales revenue was 7.2% for the three months ended March 31, 2017 as compared to 9.9% for the three months ended March 31, 2016. The decrease in production taxes as a percentage of sales revenue relates to a change in the estimated tax rate for the three months ended March 31, 2017, as well as a refund of severance tax recorded in the same period.

Exploration expenses. Our exploration expenses were $10.8 million for the three months ended March 31, 2017. We recognized $8.1 million in expense attributable to the extension of certain leases and $2.7 million in impairment expense attributable to the abandonment and impairment of unproved properties for the three months ended March 31, 2017. For the three months ended March 31, 2016, we recognized $2.8 million in exploration expenses.

Depletion, depreciation, amortization and accretion expense. Our DD&A expense increased $5.4 million to $50.7 million for the three months ended March 31, 2017 as compared to $45.3 million for the three months ended March 31, 2016. This increase is due to more volumes being sold for the three months ended March 31, 2017 as sales increased by approximately 751 MBoe. On a per unit basis, DD&A expense decreased from $20.10 per BOE for the three months ended March 31, 2016 to $16.86 per BOE for the three months ended March 31, 2017.

Impairment of long lived assets. Our impairment expense was $0.7 million for the three months ended March 31, 2017. We recognized this expense when certain well equipment inventory was evaluated to have a net realizable value less than the associated carrying value, after it was determined to no longer be useful in our current drilling operations. We recognized $0.4 million of impairment expense for the three months ended March 31, 2016 as a 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.

Other operating expenses. Other operating expenses for the three months ended March 31, 2017 is comprised of a $0.5 million loss on the sale of property and equipment. Other operating expenses for the three months ended March 31, 2016 is comprised of a $0.9 million rig termination fee in January 2016.

Acquisition transaction expenses. For the three months ended March 31, 2017 we recognized $0.1 million acquisition transaction expenses. For the three months ended March 31, 2016, we did not recognize any significant acquisition transaction expense.

General and administrative expenses. General and administrative ("G&A") expenses increased by $18.6 million to $25.7 million for the three months ended March 31, 2017 as compared to $7.1 million for the three months ended March 31, 2016. This increase is primarily due to an increase in our employee head count and stock-based compensation at for the three months ended March 31, 2017 compared to the three months ended March 31, 2016. On a per unit basis, G&A expense increased from $3.17 per BOE sold for the three months ended March 31, 2016 to $8.55 per BOE sold for the three months ended March 31, 2017.

Our G&A expenses include the non-cash expense for unit and stock-based compensation for equity awards granted to our employees and directors. For the three months ended March 31, 2017, stock-based compensation expense was $15.7 million as compared to unit-based compensation of $1.4 million for the three months ended March 31, 2016. The increase is due to additional equity awards granted to employees as part of our 2016 Long Term Incentive Plan that was adopted in October 2016 in connection with our IPO.

Commodity derivative gain (loss). Primarily due to the decrease in NYMEX crude oil futures prices at March 31, 2017 as compared to December 31, 2016 and change in fair value from the execution of new positions, we incurred a net gain on our commodity derivatives of $50.4 million for the three months ended March 31, 2017. Primarily due to the increase in NYMEX crude oil futures prices at March 31, 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 $4.0 million for the three months ended March 31, 2016, including the amortization of premiums. These gains and losses 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 March 31, 2017, we paid cash settlements of commodity derivatives totaling $9.0 million. During the three months ended March 31, 2016, we received cash settlements of commodity derivatives totaling $30.5 million.

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 March 31, 2017, we recognized interest expense of approximately $9.7 million as compared to $13.6 million for the three months ended March 31, 2016, as a result of borrowings under our revolving credit facility, Second Lien Notes in 2016, our Senior Notes and the amortization of debt issuance costs and debt discount.

We incurred interest expense for the three months ended March 31, 2017 of approximately $11.3 million related to our Senior Notes and credit facility. We incurred interest expense for the three months ended March 31, 2016 of approximately $13.3 million related to our credit facility and Second Lien Notes. Also included in interest expense for the three months ended March 31, 2017 and 2016 was the amortization of debt issuance costs and debt discount of $0.9 million and $1.2 million, respectively. For the three months ended March 31, 2017 and 2016, we capitalized interest expense of $2.5 million and $0.9 million, respectively.

Income tax expense. We recorded an income tax expense for the three months ended March 31, 2017 of $5.1 million, resulting in effective tax rate of approximately 37%. Our effective tax rate for 2017 differs from the U.S. statutory income tax rate primarily due to the effects of state income taxes and estimated permanent taxable differences. Nondeductible stock compensation expense made up the majority of the permanent items which related to the conversion of incentive units to common stock. For 2017, our combined federal and state statutory tax rate was 38%. For the three months ended March 31, 2016, we were not subject to U.S. federal income tax.

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, proceeds from the offering of our Senior Notes (please refer to *Note 4 – Long Term Debt)*, equity provided by investors, including our management team, proceeds from the IPO and a private placement of our common stock (the "Private Placement") 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 $538.7 million and $538.1 million at March 31, 2017, and December 31, 2016, respectively. We also have other contractual commitments, which are described in *Note 11 – Commitments and Contingencies* in Part I, Item I, Financial Information of the Quarterly Report.

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, make our interest payments on the Senior Notes 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.

Our 2017 capital budget is approximately $795 million to $935 million, substantially all of which we intend to allocate to the Core DJ Basin. We intend to allocate approximately $675 million to $775 million of our 2017 capital budget to the drilling of 185 to 190 gross operated wells and the completion of 190 to 195 gross operated wells, approximately $60 to $80 million of non-operated drilling and completion, and approximately $60 million to $80 million to undeveloped leasehold acquisitions, midstream, and other capital expenditures. We are currently running a three-rig program and plan to use a fourth rig on a spot basis to fill in gaps in the drilling program.

Cash Flows

The following table summarizes our cash flows for the periods indicated (in thousands):

	For the Three Months Ended March 31,	
	2017	2016
Net cash provided by operating activities	$ 19,333	$ 37,540
Net cash used in investing activities	$ (319,785)	$ (78,524)
Net cash provided by (used in) financing activities	$ (3,733)	$ 9,786

Three Months Ended March 31, 2017 Compared to the Three Months Ended March 31, 2016

Net cash provided by operating activities. For the three months ended March 31, 2017 as compared to the three months ended March 31, 2016, our net cash provided by operating activities decreased by $18.2 million, primarily due to an decrease in settlements and premiums paid on commodity derivatives of $38.2 million and a decrease in cash due to changes in current assets and liabilities of $7.6 million, partially offset by an increase in operating revenues net of expenses of $26.9 million from increased sales volumes and prices in for the three months ended March 31, 2017 compared to March 31, 2016.

Net cash used in investing activities. For the three months ended March 31, 2017 as compared to the three months ended March 31, 2016, our net cash used in investing activities increased by $241.3 million primarily due to an increase of $261.0 million used in acquisitions, drilling and completion activities and other property and equipment for the three months ended March 31, 2017 as compared to the three months ended March 31, 2016. Offsetting these decreases was the change in cash held in escrow of $19.9 million.

Net cash provided by (used in) financing activities. For the three months ended March 31, 2017 as compared to the three months ended March 31, 2016, our net cash provided by (used in) financing activities decreased by $13.5 million, as a result of a decrease of $10.0 million in proceeds from borrowings under our revolving credit facility. Additionally, for the three months ended March 31, 2017 compared to March 31, 2016 our expenditures for equity issuance costs increased by $1.3 million and our dividend payments on our Series A Preferred Stock increased by $2.2 million.

Working Capital

Our working capital was $174.8 million and $379.1 million at March 31, 2017 and December 31, 2016, respectively. Our cash balances totaled $284.6 and $588.7 million at March 31, 2017 and December 31, 2016, respectively.

Due to the amounts that we incur related to our drilling and completion program and the timing of such expenditures, we may 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 net proceeds from the IPO and the Private Placement 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, natural gas and NGL production will be the largest variables affecting our working capital.

Debt Arrangements

Our revolving credit facility has a maximum credit amount of $1.0 billion, 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 *Note 4 — Long-Term Debt* in Part 1, Item 1. Financial Information of this Quarterly Report. The revolving credit facility is secured by liens on substantially all of our properties.

In July 2016, we closed a private offering of our unsecured 7.875% Senior Notes due 2021 that resulted in net proceeds of approximately $537.2 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 was made on January 15, 2017. Our Senior Notes will mature on July 15, 2021. 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 March 31, 2017, the borrowing base was $475.0 million, and there were no borrowings outstanding under our revolving credit facility.

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 March 31, 2017, we had no outstanding borrowings under our revolving credit facility. 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 senior notes and certain derivative liabilities), 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.

In March 2017, we amended the revolving credit facility to, among other things, allow (i) XTR Midstream, LLC, one of our subsidiaries ("XTR"), to make an investment in an unaffiliated third party, so long as (A) the aggregate amount of cash contributed by XTR to such entity does not exceed $5,000,000 and (B) the amount of cash and the fair market value of the assets contributed by XTR to such entity does not exceed $10,000,000 in the aggregate, and (ii) us to enter into a transportation agreement with a wholly-owned subsidiary of such entity.

In May 2017, we amended the revolving credit facility to, among other things, allow us to (i) incur obligations under our crude oil take-or-pay arrangements, together with certain other approved transportation agreements, not to exceed $50,000,000, subject to certain exceptions, (ii) incur exposure under letters of credit not to exceed $25,000,000 that name our oil marketer as the beneficiary thereof, and (iii) enter into certain hedging arrangements under an ISDA Master Agreement between us and our oil marketer.

Senior Notes

In July 2016, we closed a private offering of our Senior Notes that resulted in net proceeds of approximately $537.2 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 was made 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.

Series A Preferred Stock

The Series A Preferred Stock are 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% per year (decreased proportionately to the extent such quarterly dividends are partially paid in cash). Each of the Series A Preferred Stock is convertible into shares of our common stock at the election of the Series A Preferred Holders at a conversion ratio per share of Series A Preferred Stock of 61.9195. Until the three-year anniversary of the closing of the IPO, we may elect to convert each share of Series A Preferred Stock at a conversion ratio 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, with such premiums decreasing 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 matures on October 15, 2021, at which time they are mandatorily redeemable for cash at the liquidation preference. For more information, see the Company's Annual Report.

Critical Accounting Policies and Estimates

There were no changes to our critical accounting policies from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2016.

Recent Accounting Pronouncements

In February 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2017-05, which provides clarification regarding the guidance on accounting for the derecognition of nonfinancial assets. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2017, including interim reporting periods within that reporting period. Early adoption is permitted for fiscal years beginning after December 15, 2016, including the interim reporting periods within that fiscal year. We are currently evaluating this new standard to determine the potential impact to our financial statements and related disclosures.

In January 2017, the FASB issued ASU No. 2017-04, which simplifies how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. Step 2 measures a goodwill impairment loss by comparing the implied fair of a reporting unit's goodwill with the carrying amount. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2019. Early adoption is permitted for interim and annual goodwill impairment tests performed on testing dates after January 1, 2017. We are currently evaluating this new standard to determine the potential impact to our financial statements and related disclosures.

In January 2017, the FASB issued ASU No. 2017-01, which clarifies the definition of a business when evaluating whether transactions should be accounted for as acquisitions or disposals of assets or businesses. 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 for transactions for which the acquisition date occurs before the issuance date or effective date of the amendments, only when the transaction has not been reported in the financial statements that have been issued. We are currently evaluating this new standard to determine the potential impact to our financial statements and related disclosures.

In December 2016, the FASB issued ASU No. 2016-19, which among other technical corrections and improvements, adds a reference to guidance to use when accounting for internal-use software licensed from third parties that is within the scope of Subtopic 350-40. For public entities, the guidance is effective upon issuance of the ASU. Adoption is permitted either (1) prospectively to all arrangements entered into or materially modified after the effective date or (2) retrospectively. We elected to adopt this guidance prospectively during the fourth quarter of 2016, which resulted in the capitalization of internal-use software licensed from third parties to goodwill and other intangible assets on the consolidated balance sheets. Costs are amortized over their respective service periods and expensed to depletion, depreciation, and amortization on the consolidated statements of operations.

In November 2016, the FASB issued ASU No. 2016-18, which intends to clarify how entities should present restricted cash and restricted cash equivalents in the statement of cash flows. This amendment will be effective retrospectively for reporting periods beginning after December 15, 2017, and early adoption is permitted. We are currently evaluating this new standard to determine the potential impact to our financial statements and related disclosures.

In August 2016, the FASB issued 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. In addition, in November 2016, the FASB issued ASU 2016-18, which requires that amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. 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. We are currently evaluating this new standard to determine the potential impact to our 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 was effective for public companies for annual and interim reporting periods beginning after December 15, 2016, including interim periods within those fiscal years. We adopted this guidance during the first quarter of 2017. As a result of adoption of this guidance, we elected to account for the forfeiture of stock-based compensation forfeitures as they occur. The adoption of this standard did not have a significant impact on our 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. We are currently evaluating the impact of adopting ASU 2016-06, however the standard is not expected to have a significant effect on our 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. We are currently evaluating the impact this new standard will have on our financial statements and related disclosures. As part of our assessment work to-date, we formed an implementation work team, completed training of the new ASU's leasing guidance, and are developing a strategy for implementation.

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, and 2016-20, which provided additional implementation guidance. We are 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 our financial statements and disclosures, as well as determining whether to use the full retrospective method or the modified retrospective method. We are currently evaluating the provisions of ASU 2014-09 and assessing the impact, if any, it may have on our financial statements and related disclosures. As part of our assessment work to-date, we have formed an implementation work team, completed training of the new ASU's revenue recognition model, and are developing a strategy for implementation.

Impact of Inflation/Deflation and Pricing

All of our transactions are denominated in U.S. dollars. Typically, as prices for oil and natural gas increase, associated costs rise. Conversely, as prices for oil and natural gas decrease, costs decline. Cost declines tend to lag and may not adjust downward in proportion to decline commodity prices. Historically, field-level prices received for our oil and natural gas production have been volatile. During the years ended December 31, 2014 and 2015, commodity prices decreased, while during the year ended December 31, 2016, commodity prices increased and remained stable during the three months ended March 31, 2017. Changes in commodity prices impact our revenues, estimates of reserves, assessments of any impairment of oil and natural gas properties, as well as values of properties being acquired or sold. Price changes have the potential to affect our ability to raise capital, borrow money, and retain personnel.

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 March 31, 2017:

	For the Three Months Ended						
	June 30, 2017	September 30, 2017	December 31, 2017	March 31, 2018	June 30, 2018	September 30, 2018	December 31, 2018
NYMEX WTI[1] Crude Swaps:							
Notional volume (Bbl)	450,000	—	—	—	—	—	—
Weighted average fixed price ($/Bbl)	$ 45.56	$ —	$ —	$ —	$ —	$ —	$ —
NYMEX WTI[1] Crude Sold Calls:							
Notional volume (Bbl)	1,300,000	2,250,000	2,250,000	1,150,000	1,050,000	750,000	750,000
Weighted average fixed price ($/Bbl)	$ 54.31	$ 56.28	$ 56.51	$ 61.80	$ 62.45	$ 62.73	$ 62.73
NYMEX WTI[1] Crude Sold Puts:							
Notional volume (Bbl)	1,175,000	2,075,000	2,175,000	900,000	900,000	750,000	750,000
Weighted average purchased put price ($/Bbl)	$ 36.62	$ 38.45	$ 38.38	$ 40.33	$ 40.33	$ 40.00	$ 40.00
NYMEX WTI[1] Crude Purchased Puts:							
Notional volume (Bbl)	1,300,000	2,250,000	2,250,000	1,050,000	1,050,000	750,000	750,000
Weighted average purchased put price ($/Bbl)	$ 46.46	$ 47.84	$ 48.04	$ 50.57	$ 50.57	$ 50.00	$ 50.00
NYMEX HH[2] Natural Gas Swaps:							
Notional volume (MMBtu)	5,590,000	7,420,000	7,420,000	4,800,000	3,600,000	3,000,000	3,000,000
Weighted average fixed price ($/MMBtu)	$ 3.04	$ 3.06	$ 3.06	$ 3.26	$ 3.04	$ 3.04	$ 3.04
NYMEX HH[2] Natural Gas Purchased Puts:							
Notional volume (MMBtu)	—	—	—	600,000	600,000	600,000	600,000
Weighted average purchased put price ($/MMBtu)	$ —	$ —	$ —	$ 3.00	$ 3.00	$ 3.00	$ 3.00
NYMEX HH[2] Natural Gas Sold Calls:							
Notional volume (MMBtu)	—	—	—	600,000	600,000	600,000	600,000
Weighted average sold call price ($/MMBtu)	$ —	$ —	$ —	$ 3.15	$ 3.15	$ 3.15	$ 3.15
CIG[3] Basis Gas Swaps:							
Notional volume (MMBtu)	2,730,000	3,680,000	3,680,000	2,250,000	—	—	—
Weighted average fixed basis price ($/MMBtu)	$ (0.38)	$ (0.38)	$ (0.32)	$ (0.29)	$ —	$ —	$ —

(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 March 31, 2017, the fair market value of our oil derivative contracts was a net asset of $0.9 million. Based on our open oil derivative positions at March 31, 2017, a 10% increase in the NYMEX WTI price would decrease our net oil derivative asset by approximately $32.9 million, while a 10% decrease in the NYMEX WTI price would increase our net oil derivative asset by approximately $27.2 million. As of March 31, 2017, the fair market value of our natural gas derivative contracts was a net liability of $4.2 million. Based upon our open commodity derivative positions at March 31, 2017, a 10% increase in the NYMEX Henry Hub price would increase our net natural gas derivative liability by approximately $11.0 million, while a 10% decrease in the NYMEX Henry Hub price would decrease our net natural gas derivate liability by approximately $11.0 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 three months ended March 31, 2017, 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 our operating results because oil, natural gas and NGL are fungible products with well-established markets and numerous purchasers.

At March 31, 2017, 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 months ended March 31, 2017 and 2016, 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 March 31, 2017, we had no variable rate debt outstanding. Assuming we had the full amount of variable-rate debt outstanding available to us at March 31, 2017 of $475.0 million, the impact on interest expense of a 1% increase or decrease in the average interest rate would be approximately $4.8 million. We may begin entering into interest rate swap arrangements on a portion of our outstanding debt to mitigate the risk of fluctuations in LIBOR if we have variable-rate debt outstanding in the future. Please see "—Liquidity and Capital Resources—Debt Arrangements."

Off-Balance Sheet Arrangements

As of March 31, 2017, we did not have any off-balance sheet arrangements other than operating leases, contractual commitments for drilling rigs, gathering commitments, and acquisitions of undeveloped leasehold acreage. Additionally, our oil marketer is subject to a firm transportation agreement with a make-whole provision that allows us to satisfy any minimum volume commitment deficiencies incurred by our oil marketer with future barrels of crude oil in excess of their minimum volume commitment through October 31, 2018. Please see *Note 11 – Commitments and Contingencies* in Part 1, Item 1 of this Quarterly Report.

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 March 31, 2017.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the three months ended March 31, 2017 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*, to our condensed consolidated financial statements included elsewhere in this report.

We are currently in discussions with the Colorado Department of Public Health and Environment (“CDPHE”) regarding a Compliance Advisory issued to us in July 2015, which alleged air quality violations at three of our facilities regarding leakages of volatile organic compounds from storage tanks, all of which were promptly addressed. On August 12, 2016, the CDPHE expanded its investigation to several additional facilities of ours and, on December 7, 2016 indicated to us that it is further expanding its investigation to our other facilities in Colorado and intends to seek a field-wide administrative settlement of these issues. At this time we cannot predict the outcome of this matter or the remediation or compliance costs that this matter may impose upon us.

From time to time, we may be involved in litigation relating to claims arising out of our business and operations in the normal course of business. As of the filing date of this report, no legal proceedings are pending against us that we believe individually or collectively could have a materially adverse effect upon our financial condition, results of operations or cash flows.

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 Item 1A “Risk Factors”, included in our Annual Report. 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

None.

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: May 9, 2017.

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
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).
*10.1	Amendment No. 11 to the Credit Agreement, dated as of March 15, 2017, by and among Extraction Oil & Gas, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto.
*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

* Filed herewith.
** Furnished herewith.

AMENDMENT NO. 11 TO CREDIT AGREEMENT

This Amendment No. 11 to Credit Agreement (this "Agreement") dated as of March 15, 2017 (the "Effective Date"), is among Extraction Oil & Gas, Inc., a Delaware corporation (the "Borrower"), 7N, LLC, a Delaware limited liability company, 8 North, LLC, a Delaware limited liability company, Bison Exploration, LLC, a Delaware limited liability company, Elevation Midstream, LLC, a Delaware limited liability company, Extraction Finance Corp., a Delaware corporation, Mountaintop Minerals, LLC, a Delaware limited liability company, XOG Services, LLC, a Delaware limited liability company, XOG Services, Inc., a Colorado corporation, and XTR Midstream, LLC, a Delaware limited liability company ("XTR"; and together with the other entities listed subsequent to the Borrower above, collectively, the "Guarantors"), the undersigned Lenders (as defined below), and Wells Fargo Bank, National Association, as Administrative Agent for the Lenders (in such capacity, the "Administrative Agent") and as Issuing Lender (the "Issuing Lender").

INTRODUCTION

A. The Borrower, the financial institutions party thereto as lenders (the "Lenders"), the Issuing Lender, and the Administrative Agent have entered into the Credit Agreement dated as of September 4, 2014, as amended by the Amendment No. 1 dated as of September 24, 2014, the Amendment No. 2 and Joinder dated as of November 10, 2014, the Amendment No. 3 dated as of December 30, 2014, the Waiver dated as of February 12, 2015, the Consent Agreement dated as of February 27, 2015, the Consent Agreement dated as of March 25, 2015, the Waiver dated as of April 28, 2015, the Amendment No. 4 and Joinder dated as of May 27, 2015, the Amendment No. 5 dated as of September 1, 2015, the Amendment No. 6 dated as of September 10, 2015, the Amendment No. 7 and Joinder dated as of December 15, 2015, the Amendment No. 8 and Joinder dated as of June 13, 2016, the Amendment No. 9 dated as of August 12, 2016, and the Consent, Amendment No. 10 and Joinder dated September 14, 2016 (as so amended and modified and as may be otherwise amended, restated, or modified from time to time, the "Credit Agreement").

B. The Guarantors have entered into the Guaranty Agreement dated as of September 4, 2014 (as amended, restated, supplemented or otherwise modified from time to time, the "Guaranty") in favor of the Administrative Agent for the benefit of the Secured Parties (as defined in the Credit Agreement).

C. XTR desires to contribute cash and certain midstream assets in exchange for approximately 15% of the Equity Interest (as defined in the Credit Agreement) of Platte River Holdings LLC, a Delaware limited liability company ("PRH"), pursuant to that certain Contribution Agreement to be entered into on or about the Effective Date, among ARB Platte River, LLC, a Colorado limited liability company ("ARB"), XTR and PRH (the "Proposed Contribution").

D. Contemporaneously with the Proposed Contribution, (i) ARB and XTR will enter into that certain First Amended and Restated Limited Liability Company Agreement of PRH to be entered into on or about the Effective Date and (ii) Platte River Midstream, LLC, a Delaware limited liability company and wholly-owned subsidiary of PRH ("PRM"), and the Borrower will enter into that certain First Amended and Restated Transportation Services Agreement to be entered into on or about the Effective Date, pursuant to which the Borrower will agree to ship or pay to ship certain committed volumes of hydrocarbons on midstream infrastructure owned and operated by PRM (the "Proposed Shipping Arrangement").

E. The Borrower has requested that the Lenders and the Administrative Agent, and the Administrative Agent and the Lenders have agreed, subject to the terms and conditions hereof, amend the Credit Agreement as set forth herein to permit each of the Proposed Contribution and the Proposed Shipping Arrangement.

THEREFORE, in fulfillment of the foregoing, the Borrower, the Guarantors, the Administrative Agent, the Issuing Lender, and the undersigned Lenders hereby agree as follows:

Section 1. Definitions; References. Unless otherwise defined in this Agreement, each term used in this Agreement which is defined in the Credit Agreement has the meaning assigned to such term in the Credit Agreement, as amended hereby.

Section 2. Amendments to Credit Agreement. Upon the satisfaction of the conditions specified in Section 6 of this Agreement, and effective as of the date set forth above, the Credit Agreement is amended as follows:

(a) Section 1.1 of the Credit Agreement (*Certain Defined Terms*) is amended to add the following defined terms in alphabetical order:

(1) *"Amendment No. 11" means that certain Amendment No. 11 to Credit Agreement dated as of March 15, 2017, among the Loan Parties, the Administrative Agent, the Issuing Lender, and the Lenders party thereto.*

(2) *"Amendment No. 11 Effective Date" means March 15, 2017.*

(3) *"PRH" means Platte River Holdings LLC, a Delaware limited liability company.*

(4) *"PRM" means Platte River Midstream, LLC, a Delaware limited liability company, and a wholly-owned subsidiary of PRH.*

(5) *"PRH Contribution Agreement" means that certain Contribution Agreement among ARB Platte River, LLC, a Colorado limited liability company, XTR and PRH, substantially in the form delivered to the Administrative Agent on or prior to the Amendment No. 11 Effective Date, with such changes and modifications that are not materially adverse to the Lenders.*

(6) *"PRH LLC Agreement" means that certain First Amended and Restated Limited Liability Company Agreement of PRM, substantially in the form delivered to the Administrative Agent on or prior to the Amendment No. 11 Effective Date, with such changes and modifications that are not materially adverse to the Lenders, and as such agreement may be amended from time to time in a manner not materially adverse to the Lenders.*

(7) *"PRM Transportation Agreement" means that certain First Amended and Restated Transportation Services Agreement, between Borrower and PRM, substantially in the form delivered to the Administrative Agent on or prior to the Amendment No. 11 Effective Date, with such changes and modifications that are not materially adverse to the Lenders.*

(b) Section 1.1 of the Credit Agreement (*Certain Defined Terms*) is further amended by replacing the defined term *"Approved Transportation Agreements"* in its entirety with the following:

> *"Approved Transportation Agreements" means the Grand Mesa Agreements, the Tallgrass Letter Agreement, the PRM Transportation Agreement and such other transportation services agreements as may be approved by the Majority Lenders in writing, in each case, together with such changes thereto as may be approved by the Administrative Agent.*

(c) Section 6.3 of the Credit Agreement (*Investments*) is amended by deleting the "*and*" at the end of clause (f) thereof and replacing clause (g) thereof with the following clause (g) and new clause (h):

> *(g) the investment made by XTR in PRH pursuant to the PRH Contribution Agreement and the PRH LLC Agreement so long as (i) the aggregate amount of cash contributed by XTR to PRH pursuant thereto does not exceed $5,000,000 and (ii) the amount of cash and the fair market value of the assets contributed by XTR to PRH pursuant thereto does not exceed $10,000,000 in the aggregate; and*
>
> *(h) other investments in an aggregate amount not to exceed $5,000,000.*

(d) Section 6.8 of the Credit Agreement (*Sale of Assets*) is amended by replacing clause (h) thereof in its entirety with the following:

> *(h) (i) Permitted Investments of the type described in Section 6.3(g) and (ii) other Asset Sales of Property not constituting Oil and Gas Properties and not otherwise permitted by this Section 6.8, the aggregate consideration of which shall not exceed $5,000,000 during the term of this Agreement; and*

(e) Article 6 of the Credit Agreement (*Negative Covenants*) is further amended by adding the following new Section 6.27 to the end thereof:

> *6.27 PRH and PRM. Notwithstanding anything to the contrary contained herein, no Loan Party shall, nor shall it permit any of its Subsidiaries to, create, assume, incur or suffer to exist any Lien on or in respect of any of its Property for the benefit of PRH or PRM.*

Section 3. Reaffirmation of Liens.

(a) Each of the Borrower and each Guarantor (i) is party to certain Security Documents securing and supporting the Borrower's and Guarantors' obligations under the Loan

Documents, (ii) represents and warrants that it has no defenses to the enforcement of the Security Documents and that according to their terms the Security Documents will continue in full force and effect to secure the Borrower's and Guarantors' obligations under the Loan Documents, as the same may be amended, supplemented, or otherwise modified, and (iii) acknowledges, represents, and warrants that the liens and security interests created by the Security Documents are valid and subsisting and create a first and prior Lien (subject only to Permitted Liens) in the Collateral to secure the Secured Obligations.

(b) The delivery of this Agreement does not indicate or establish a requirement that any Loan Document requires any Guarantor's approval of amendments to the Credit Agreement.

Section 4. Reaffirmation of Guaranty. Each Guarantor hereby ratifies, confirms, and acknowledges that its obligations under the Guaranty and the other Loan Documents are in full force and effect and that such Guarantor continues to unconditionally and irrevocably guarantee the full and punctual payment, when due, whether at stated maturity or earlier by acceleration or otherwise, of all of the Guaranteed Obligations (as defined in the Guaranty), as such Guaranteed Obligations may have been amended by this Agreement. Each Guarantor hereby acknowledges that its execution and delivery of this Agreement does not indicate or establish an approval or consent requirement by such Guarantor under the Credit Agreement in connection with the execution and delivery of amendments, modifications or waivers to the Credit Agreement, the Notes or any of the other Loan Documents.

Section 5. Representations and Warranties. Each of the Borrower and each Guarantor represents and warrants to the Administrative Agent and the Lenders that:

(a) the representations and warranties set forth in the Credit Agreement and in the other Loan Documents are true and correct in all material respects as of the date of this Agreement (except to the extent such representations and warranties relate to an earlier date, in which case such representations and warranties shall be true and correct in all material respects as of such earlier date); provided that such materiality qualifier shall not apply if such representation or warranty is already subject to a materiality qualifier in the Credit Agreement or such other Loan Document;

(b) (i) the execution, delivery, and performance of this Agreement are within the corporate, limited partnership or limited liability company power, as appropriate, and authority of the Borrower and Guarantors and have been duly authorized by appropriate proceedings and (ii) this Agreement constitutes a legal, valid, and binding obligation of the Borrower and Guarantors, enforceable against the Borrower and Guarantors in accordance with its terms, except as limited by applicable bankruptcy, insolvency, reorganization, moratorium, or similar laws affecting the rights of creditors generally and general principles of equity; and

(c) as of the effectiveness of this Agreement and after giving effect thereto, no Default or Event of Default has occurred and is continuing.

Section 6. Effectiveness. This Agreement shall become effective as of the date hereof upon the occurrence of all of the following:

(a) Documentation. The Administrative Agent shall have received this Agreement, duly and validly executed by the Borrower, the Guarantors, the Administrative Agent, the Issuing Bank and the Majority Lenders, in form and substance reasonably satisfactory to the Administrative Agent and the Majority Lenders;

(b) Representations and Warranties. The representations and warranties in this Agreement being true and correct in all material respects before and after giving effect to this Agreement (except to the extent such representations and warranties relate to an earlier date, in which case such representations and warranties shall be true and correct in all material respects as of such earlier date); provided that such materiality qualifier shall not apply if such representation or warranty is already subject to a materiality qualifier in the Credit Agreement or such other Loan Document.

(c) No Default or Event of Default. There being no Default or Event of Default which has occurred and is continuing.

(d) Expenses. The Borrower's having paid all costs, expenses, and fees which have been invoiced and are payable pursuant to Section 9.1 of the Credit Agreement or any other agreement.

Section 7. Post-Closing Obligations. On or before 5:00 p.m. (Houston, Texas time) on the effective date of the Proposed Contribution, the Borrower shall deliver to the Administrative Agent certified, fully executed, correct and complete copies of the PRH Contribution Agreement, the PRH LLC Agreement, and the PRM Transportation Agreement, in each case, as in effect on the Effective Date. The Borrower's failure to satisfy the obligations set forth in this Section 7 shall constitute an immediate Event of Default under this Agreement and the Credit Agreement.

Section 8. Effect on Loan Documents. Except as amended herein, the Credit Agreement and the Loan Documents remain in full force and effect as originally executed and are hereby ratified and confirmed, and nothing herein shall act as a waiver of any of the Administrative Agent's or Lenders' rights under the Loan Documents. This Agreement is a Loan Document for the purposes of the provisions of the other Loan Documents. Without limiting the foregoing, any breach of representations, warranties, and covenants under this Agreement is a Default or Event of Default under other Loan Documents.

Section 9. Choice of Law. This Agreement shall be governed by and construed and enforced in accordance with the laws of the State of New York without regard to conflicts of laws principles (other than Sections 5-1401 and 5-1402 of the General Obligations Law of the State of New York).

Section 10. Counterparts. This Agreement may be signed in any number of counterparts, each of which shall be an original.

THIS WRITTEN AGREEMENT AND THE LOAN DOCUMENTS, AS DEFINED IN THE CREDIT AGREEMENT, REPRESENT THE FINAL AGREEMENT AMONG THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS, OR SUBSEQUENT ORAL AGREEMENTS

OF THE PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN THE PARTIES.

[*Remainder of page intentionally left blank; Signature pages follow.*]

EXECUTED as of the date first set forth above.

BORROWER:

EXTRACTION OIL & GAS, INC.

By: /s/ Matthew R. Owens
Name: Matthew R Owens
Title: President

GUARANTORS:

7N, LLC
8 NORTH, LLC
BISON EXPLORATION, LLC
ELEVATION MIDSTREAM, LLC
EXTRACTION FINANCE CORP.
MOUNTAINTOP MINERALS, LLC
XOG SERVICES, INC.
XOG SERVICES, LLC
XTR MIDSTREAM, LLC

Each By: /s/ Matthew R. Owens
Name: Matthew R Owens
Title: President

ADMINISTRATIVE AGENT/ISSUING LENDER/LENDER:

WELLS FARGO BANK, NATIONAL ASSOCIATION,
As Administrative Agent, Issuing Lender, and a Lender

By: /s/ Zachary Kramer
Name: Zachary Kramer
Title: Assistant Vice President

LENDERS:

ROYAL BANK OF CANADA
as a Lender

By: /s/ Kristan Spivey
Name: Kristan Spivey
Title: Authorized Signatory

BOKF, NA, dba Bank of Oklahoma,
as a Lender

By: /s/ Benjamin H. Adler
Name: Benjamin H. Adler
Title: Vice President

[SIGNATURE PAGE TO AMENDMENT NO. 11 TO CREDIT AGREEMENT – EXTRACTION]

GOLDMAN SACHS BANK USA,
as a Lender

By: /s/ Ushma Dedhiya
Name: Ushma Dedhiya
Title: Authorized Signatory

FIFTH THIRD BANK,
as a Lender

By: /s/ Jonathan H. Lee
Name: Jonathan H. Lee
Title: Director

SUNTRUST BANK,
as a Lender

By: /s/ Arize Agumadu
Name: Arize Agumadu
Title: Vice President

KEYBANK NATIONAL ASSOCIATION,
as a Lender

By: /s/ Paul Pace
Name: Paul Pace
Title: Senior Vice President

BARCLAYS BANK PLC,
as a Lender

By:	/s/ Graeme Palmer
Name:	Graeme Palmer
Title:	Assistant Vice President

ABN AMRO CAPITAL USA LLC,
as a Lender

By: /s/ Darrell Holley
Name: Darrell Holley
Title: Managing Director

By: /s/ Michaela Braun
Name: Michaela Braun
Title: Director

CREDIT SUISSE AG,
CAYMAN ISLANDS BRANCH,
as a Lender

By: /s/ Nupur Kumar
Name: Nupur Kumar
Title: Authorized Signatory

By: /s/ Lea Baerlocher
Name: Lea Baerlocher
Title: Authorized Signatory

CITIBANK, N.A.,
as a Lender

By: /s/ Phil Ballard
Name: Phil Ballard
Title: Vice President

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 on Form 10-Q (this "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: May 9, 2017

/S/ MARK A. ERICKSON

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

EXHIBIT 31.2

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

1. I have reviewed this quarterly report on Form 10-Q (this “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: May 9, 2017

/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 on Form 10-Q for the quarterly period ended March 31, 2017 of Extraction Oil & Gas, Inc. (the "Company"), as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, 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: May 9, 2017

/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 on Form 10-Q for the quarterly period ended March 31, 2017 of Extraction Oil & Gas, Inc. (the "Company"), as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, 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: May 9, 2017

/S/ RUSSELL T. KELLEY JR.

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