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

FORM 10-Q

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

For the quarterly period ended September 30, 2018

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 every Interactive Data File required to be submitted 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 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.

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 November 2, 2018 was 176,188,312.

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., together with its consolidated subsidiaries. When the context requires, we refer to these entities separately.

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

"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, which is calculated as NYMEX Henry Hub index price less the Rocky Mountains (CIGC) Inside FERC fixed price.

"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.

"Fracturing" or "hydraulic fracturing" means a procedure to stimulate production by forcing a mixture of fluid and proppant (usually sand) into the formation under high pressure. This creates artificial fractures in the reservoir rock, which increases permeability and porosity.

"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.

"NGL" means natural gas liquids.

"NYMEX" means New York Mercantile Exchange.

"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.

"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.

"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.

"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.

"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)

	September 30, 2018	December 31, 2017
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 274,065	$ 6,768
Accounts receivable		
Trade	44,565	46,047
Oil, natural gas and NGL sales	107,166	93,301
Inventory and prepaid expenses	26,676	13,017
Commodity derivative asset	13,226	4,132
Total Current Assets	465,698	163,265
Property and Equipment (successful efforts method), at cost:		
Proved oil and gas properties	3,778,498	3,011,526
Unproved oil and gas properties	657,837	686,968
Wells in progress	108,426	127,418
Less: accumulated depletion, depreciation and amortization	(1,029,539)	(709,662)
Net oil and gas properties	3,515,222	3,116,250
Gathering systems and facilities	63,998	4,889
Other property and equipment, net of accumulated depreciation	37,829	32,429
Net Property and Equipment	3,617,049	3,153,568
Non-Current Assets:		
Goodwill and other intangible assets, net of accumulated amortization	56,446	55,453
Other non-current assets	19,132	12,383
Total Non-Current Assets	75,578	67,836
Total Assets	$ 4,158,325	$ 3,384,669
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 200,137	$ 211,581
Revenue payable	113,751	52,805
Production taxes payable	61,497	37,444
Commodity derivative liability	143,576	67,428
Accrued interest payable	18,792	23,807
Asset retirement obligations	12,928	6,873
Total Current Liabilities	550,681	399,938
Non-Current Liabilities:		
Credit facility	290,000	90,000
Senior Notes, net of unamortized debt issuance costs	1,132,115	933,361
Production taxes payable	83,586	57,982
Commodity derivative liability	8,786	17,274
Other non-current liabilities	8,966	5,973
Asset retirement obligations	56,423	62,667
Deferred tax liability	54,626	42,326
Total Non-Current Liabilities	1,634,502	1,209,583
Total Liabilities	2,185,183	1,609,521
Commitments and Contingencies—Note 11		
Series A Convertible Preferred Stock, $0.01 par value; 50,000,000 shares authorized; 185,280 issued and outstanding	162,813	158,383
Stockholders' Equity:		
Common stock, $0.01 par value; 900,000,000 shares authorized; 175,861,466 and 172,059,814 issued and outstanding	1,718	1,718
Additional paid-in capital	2,146,918	2,114,795
Treasury stock, at cost, 485,117 and 165,385 shares	(6,539)	(2,105)

Accumulated deficit	(475,640)	(497,643)
Total Extraction Oil & Gas, Inc. Stockholders' Equity	1,666,457	1,616,765
Noncontrolling interest—Note 1	143,872	—
Total Stockholders' Equity	1,810,329	1,616,765
Total Liabilities and Stockholders' Equity	$ 4,158,325	$ 3,384,669

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 September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
Revenues:				
Oil sales	$ 225,467	$ 132,075	$ 619,211	$ 269,597
Natural gas sales	23,103	24,672	66,991	63,095
NGL sales	33,590	24,114	86,369	57,574
Total Revenues	282,160	180,861	772,571	390,266
Operating Expenses:				
Lease operating expenses	20,283	15,465	61,760	41,626
Transportation and gathering	11,786	13,802	29,284	34,129
Production taxes	21,605	16,290	66,317	33,254
Exploration expenses	11,038	7,181	21,326	24,431
Depletion, depreciation, amortization and accretion	107,315	94,220	310,296	213,483
Impairment of long lived assets	16,166	—	16,294	675
(Gain) loss on sale of property and equipment and assets of unconsolidated subsidiary	(83,559)	—	(143,461)	451
Acquisition transaction expenses	—	—	—	68
General and administrative expenses	35,365	28,741	100,565	77,916
Total Operating Expenses	139,999	175,699	462,381	426,033
Operating Income (Loss)	142,161	5,162	310,190	(35,767)
Other Income (Expense):				
Commodity derivatives gain (loss)	(35,913)	(37,875)	(175,752)	46,423
Interest expense	(20,725)	(15,080)	(103,229)	(33,761)
Other income	1,827	891	3,094	1,709
Total Other Income (Expense)	(54,811)	(52,064)	(275,887)	14,371
Income (Loss) Before Income Taxes	87,350	(46,902)	34,303	(21,396)
Income tax (expense) benefit	(22,200)	17,106	(12,300)	7,556
Net Income (Loss)	$ 65,150	$ (29,796)	$ 22,003	$ (13,840)
Income (Loss) Per Common Share (Note 10)				
Basic and diluted	$ 0.33	$ (0.20)	$ 0.03	$ (0.15)
Weighted Average Common Shares Outstanding				
Basic and diluted	175,814	171,845	175,269	171,838

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

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

	Common Stock		Treasury Stock					Noncontrolling Interest	
	Shares	Amount	Shares	Amount	Additional Paid in Capital	Retained Deficit	Extraction Oil & Gas, Inc. Stockholders' Equity	Amount	Total Stockholders' Equity
Balance at January 1, 2018	172,060	$ 1,718	165	$ (2,105)	$ 2,114,795	$ (497,643)	$ 1,616,765	$ —	$ 1,616,765
Preferred Units issued	—	—	—	—	—	—	—	148,500	148,500
Preferred Units issuance costs	—	—	—	—	—	—	—	(7,933)	(7,933)
Preferred Units commitment fees and dividends paid-in-kind	—	—	—	—	(3,305)	—	(3,305)	3,305	—
Stock-based compensation	2,794	—	—	—	50,883	—	50,883	—	50,883
Series A Preferred Stock dividends	—	—	—	—	(8,164)	—	(8,164)	—	(8,164)
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	(4,429)	—	(4,429)	—	(4,429)
Repurchase of common stock	—	—	320	(4,434)	—	—	(4,434)	—	(4,434)
Shares issued under LTIP, including payment of tax withholdings using withheld shares	1,007	—	—	—	(2,862)	—	(2,862)	—	(2,862)
Net income	—	—	—	—	—	22,003	22,003	—	22,003
Balance at September 30, 2018	175,861	$ 1,718	485	$ (6,539)	$ 2,146,918	$ (475,640)	$ 1,666,457	$ 143,872	$ 1,810,329

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 Nine Months Ended September 30, 2018	2017
Cash flows from operating activities:		
Net income (loss)	$ 22,003	$ (13,840)
Reconciliation of net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, amortization and accretion	310,296	213,483
Abandonment and impairment of unproved properties	15,463	5,684
Impairment of long lived assets	16,294	675
(Gain) loss on sale of property and equipment	(59,849)	451
Gain on sale of assets of unconsolidated subsidiary	(83,612)	—
Amortization of debt issuance costs	12,303	3,181
Deferred rent	442	(229)
Commodity derivatives (gain) loss	175,752	(46,423)
Settlements on commodity derivatives	(93,482)	(8,893)
Premiums paid on commodity derivatives	(17,271)	—
Earnings in unconsolidated subsidiaries	(1,886)	(256)
Distributions from unconsolidated subsidiaries	1,684	131
Make-whole premium expense on 2021 Senior Notes	35,600	—
Deferred income tax expense (benefit)	12,300	(7,556)
Stock-based compensation	50,883	46,707
Changes in current assets and liabilities:		
Accounts receivable—trade	4,573	(29,099)
Accounts receivable—oil, natural gas and NGL sales	(13,865)	(36,359)
Inventory and prepaid expenses	(637)	(180)
Accounts payable and accrued liabilities	(14,780)	1,653
Revenue payable	60,946	6,047
Production taxes payable	49,657	13,520
Accrued interest payable	(5,015)	(5,553)
Asset retirement expenditures	(9,437)	(1,408)
Net cash provided by operating activities	468,362	141,736
Cash flows from investing activities:		
Oil and gas property additions	(774,787)	(1,015,700)
Acquired oil and gas properties	—	(17,225)
Sale of property and equipment	72,345	5,155
Gathering systems and facilities additions	(41,359)	(7,685)
Other property and equipment additions	(11,944)	(1,923)
Investment in unconsolidated subsidiaries	(6,000)	—
Distributions from unconsolidated subsidiary, return of capital	—	116
Sale of assets of unconsolidated subsidiary	83,612	—
Net cash used in investing activities	(678,133)	(1,037,262)
Cash flows from financing activities:		
Borrowings under credit facility	590,000	250,000
Repayments under credit facility	(390,000)	(250,000)
Proceeds from the issuance of 2026 Senior Notes	739,664	394,000
Repayments of 2021 Senior Notes	(550,000)	—
Make-whole premium paid on 2021 Senior Notes	(35,600)	—
Proceeds from issuance of Preferred Units	148,500	—
Preferred Unit issuance costs	(6,933)	—
Repurchase of shares	(4,434)	—
Payment of employee payroll withholding taxes	(2,862)	(2,832)
Dividends on Series A Preferred Stock	(8,164)	(7,680)

Debt issuance costs	(3,103)	(3,273)
Equity issuance costs	—	(1,486)
Net cash provided by financing activities	477,068	378,729
Increase (decrease) in cash, cash equivalents and restricted cash	267,297	(516,797)
Cash, cash equivalents and restricted cash at beginning of period	6,768	630,936
Cash, cash equivalents and restricted cash at end of the period	$ 274,065	$ 114,139

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

Supplemental cash flow information:				
Property and equipment included in accounts payable and accrued liabilities	$	148,156	$	130,022
Cash paid for interest	$	66,673	$	44,703
Issuance of promissory note to unconsolidated subsidiary	$	35,329	$	—
Extinguishment of promissory note in exchange for equity with unconsolidated subsidiary	$	(35,329)	$	—
Accretion of beneficial conversion feature of Series A Preferred Stock	$	4,429	$	3,992
Non-cash contribution to unconsolidated subsidiary	$	—	$	8,307
Increase in dividend payable	$	—	$	484
Preferred Units commitment fees and dividends paid-in-kind	$	3,305	$	—

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 and its subsidiaries are 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".

On July 3, 2018, Elevation Midstream, LLC ("Elevation"), a Delaware limited liability company and subsidiary of the Company, entered into a securities purchase agreement (the "Securities Purchase Agreement") with a third party (the "Purchaser"), pursuant to which Elevation agreed to sell 150,000 Preferred Units (the "Elevation Preferred Units") of Elevation at a price of $990 per Elevation Preferred Unit with an aggregate liquidation preference of $150.0 million (the "Private Placement"), in a transaction exempt from the registration requirements under the Securities Act of 1933, as amended (the "Securities Act"). The Private Placement closed on July 3, 2018 (the "Closing Date"), funded on July 19, 2018 and resulted in net proceeds of approximately $141.9 million, $25.4 million of which was a reimbursement for previously incurred midstream capital expenditures and general and administrative expenses. These Preferred Units are non-recourse to Extraction and represent the noncontrolling interest presented on the condensed consolidated statement of changes in stockholders' equity. Elevation is a separate entity and the assets and credit of Elevation are not available to satisfy the debts and other obligations of the Company or its other subsidiaries. As of September 30, 2018, $182.0 million of cash was held by Elevation and is earmarked for construction of pipeline infrastructure to serve the development of acreage in its Hawkeye and Southwest Wattenberg areas. As of September 30, 2018 and December 31, 2017, Elevation capital expenditures represented all of the gathering systems and facilities line item in the condensed consolidated balance sheet and the gathering systems and facilities additions in the condensed consolidated statement of cash flows.

During the twenty-eight months following the Closing Date (the "Commitment Period"), subject to the satisfaction of certain financial and operational metrics and certain other customary closing conditions, Elevation has the right to require the Purchaser to purchase additional Elevation Preferred Units on the terms set forth in the Securities Purchase Agreement. Elevation may require the Purchaser to purchase additional Elevation Preferred Units, in increments of at least $25.0 million, up to an aggregate amount of $350.0 million. During the Commitment Period, Elevation is required to pay the Purchaser a quarterly commitment fee payable in cash or in kind of 1.0% per annum on any undrawn amounts of such additional $350.0 million commitment. Elevation recognized $0.9 million of commitment fees paid-in-kind for the three and nine months ended September 30, 2018, included under the Preferred Unit commitment fees and dividends paid-in-kind line item in the condensed consolidated statement of changes in stockholders' equity.

The Elevation Preferred Units will entitle the Purchaser to receive quarterly dividends at a rate of 8.0% per annum (the "Dividend"). In respect of quarters ending prior to and including June 30, 2020, the Dividend is payable in cash or in kind at the election of Elevation. After June 30, 2020, the Dividend is payable solely in cash. Elevation recognized $2.4 million of dividends paid-in-kind for the three and nine months ended September 30, 2018, included under the Preferred Unit commitment fees and dividends paid-in-kind line item in the condensed consolidated statement of changes in stockholders' equity.

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 Securities and Exchange Commission 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 condensed 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 condensed consolidated financial statements should be read in conjunction with the Company's audited consolidated 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 August 2018, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2018-15, which aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software and hosting arrangements that include an internal-use software license. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2019, including interim reporting periods within that reporting period. The Company is currently evaluating this new standard to determine the potential impact to its financial statements and related disclosures.

In August 2018, the FASB issued ASU No. 2018-13, which improves the disclosure requirements on fair value measurements. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2019, including interim reporting periods within that reporting period. The Company is currently evaluating this new standard to determine the potential impact to its financial statements and related disclosures.

In May 2017, the FASB issued ASU No. 2017-09, which provides clarification and reduces both (1) diversity in practice and (2) cost and complexity when applying the guidance in Topic 718 Compensation - Stock Compensation, to a change to the terms or conditions of a share-based payment award. For public entities, the new guidance was effective for fiscal years beginning after December 15, 2017, including interim reporting periods within that reporting period. The Company adopted this ASU on January 1, 2018 and the adoption of this ASU did not have a material impact on the consolidated financial statements and related disclosures.

In February 2017, the FASB issued ASU No. 2017-05, which provided clarification regarding the guidance on accounting for the derecognition of nonfinancial assets. For public entities, the new guidance was effective for fiscal years beginning after December 15, 2017, including interim reporting periods within that fiscal year. The Company adopted this ASU on January 1, 2018 and the adoption of this ASU did not have a material impact on the consolidated 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 value 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 the impact of adopting this ASU, however it is not expected to have a significant effect on its consolidated 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 was effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. The Company adopted this ASU on January 1, 2018 and the adoption of this ASU did not have a material impact on the consolidated financial statements and related disclosures; however, this standard may result in more transactions being accounted for as asset acquisitions rather than business combinations.

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 was effective retrospectively for reporting periods beginning after December 15, 2017. The Company adopted this ASU on January 1, 2018 and the retrospective adoption increased the Company's beginning cash balances within the statement of cash flows for the prior period presented in the table below. The adoption had no other material impact on the cash flow statement and had no impact on the Company's results of operations or financial position.

The following table provides a reconciliation of cash, cash equivalents and restricted cash reported within the consolidated balance sheets to the consolidated statement of cash flows:

	As of			
	September 30, 2018	December 31, 2017	September 30, 2017	December 31, 2016
Cash and cash equivalents	$ 274,065	$ 6,768	$ 114,139	$ 588,736
Restricted cash included in cash held in escrow	—	—	—	42,200
	$ 274,065	$ 6,768	$ 114,139	$ 630,936

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. For public entities, the new guidance was effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. The Company adopted this ASU on January 1, 2018, which requires current period make-whole premiums to be presented in financing activities in the statement of cash flows and prior period debt prepayment costs to be reclassified from operating activities to financing activities in the statement of cash flows; however, there will be no impact to the total change in cash and cash equivalents from period to period.

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 FASB subsequently issued ASU No. 2017-13, ASU No. 2018-01, ASU No. 2018-10 and ASU No. 2018-11, which provided additional implementation guidance. The Company is currently evaluating the impact this ASU will have on the consolidated financial statements and related disclosures and expects certain lease agreements with terms over one year to be classified as right-of-use assets and right-of-use liabilities, which will gross up the consolidated balance sheet as of January 1, 2019. As a part of the implementation work, the Company is finalizing its initial conclusions with its external consulting firm, implementing a software tool used to calculate the initial and ongoing accounting balances for right-of-use assets and liabilities, and is assessing the completeness of the lease population.

In May 2014, the FASB issued ASU No. 2014-09, which establishes a comprehensive new revenue recognition model, referred to as ASC 606 - Revenue from Contracts with Customers, 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 was effective for annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period. The FASB subsequently issued ASU No. 2016-08, ASU No. 2016-10, ASU No. 2016-11, ASU No. 2016-12, ASU No. 2016-20, ASU No. 2017-13 and ASU No. 2017-14, which provided additional implementation guidance. Refer to *—Adoption of ASC 606* for more information.

Adoption of ASC 606

On January 1, 2018, the Company adopted ASC 606 - Revenue from Contracts with Customers ("ASC 606"). The Company adopted ASC 606 using the modified retrospective method to apply the new standard to all new contracts entered into on or after January 1, 2018 and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance. ASC 606 supersedes previous revenue recognition requirements in ASC 605 and includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services.

The impact of adoption in the current period results are as follows (in thousands):

	For the Three Months Ended September 30, 2018			For the Nine Months Ended September 30, 2018		
	Under ASC 606	Under ASC 605	Change	Under ASC 606	Under ASC 605	Change
Revenues:						
Oil sales	$ 225,467	$ 225,467	$ —	$ 619,211	$ 619,211	$ —
Natural gas sales	23,103	26,394	(3,291)	66,991	76,492	(9,501)
NGL sales	33,590	39,154	(5,564)	86,369	101,349	(14,980)
Total Revenues	282,160	291,015	(8,855)	772,571	797,052	(24,481)
Operating Expenses:						
Transportation and gathering	$ 11,786	$ 20,641	$ (8,855)	$ 29,284	$ 53,765	$ (24,481)
Net Income	$ 65,150	$ 65,150	$ —	$ 22,003	$ 22,003	$ —

Changes to sales of natural gas and NGL, and transportation and gathering expenses are due to the conclusion that certain midstream processing entities are the Company's customers in natural gas processing and marketing agreements in accordance with the five-step process in ASC 606. This is a change from previous conclusions reached for these agreements utilizing the principal versus agent indicators under ASC 605 where the Company determined it was the principal, the midstream processor was the agent and the third-party end user was its customer. As a result, the Company modified its presentation of revenues and operating expenses for these agreements. Revenues related to these agreements are now presented on a net basis for proceeds expected to be received from the midstream processing entity.

Transportation and gathering expense related to other agreements incurred prior to the transfer of control to the customer at the tailgate of the natural gas processing facilities will continue to be presented as transportation and gathering expense.

Revenues from Contracts with Customers

Sales of oil, natural gas and NGL are recognized at the point control of the commodity is transferred to the customer and collectability is reasonably assured. The majority of the Company's contracts' pricing provisions are tied to a commodity market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of the oil or natural gas, and prevailing supply and demand conditions. As a result, the price of the oil, natural gas and NGL fluctuates to remain competitive with the other available oil, natural gas and NGL supplies.

Oil Sales

Under the Company's crude purchase and marketing contracts, the Company generally sells oil production at the wellhead and collects an agreed-upon index price, net of pricing differentials. In this scenario, the Company recognizes revenue when control transfers to the purchaser at the wellhead at the net price received.

The Company utilizes the sales method to account for producer imbalances, which continues to be applicable under ASC 606. As of September 30, 2018, the Company has an oil imbalance of 54 MBbl, which the Company intends to settle with the counterparty in crude oil barrels.

Natural Gas and NGL Sales

Under the Company's natural gas processing contracts, the Company delivers natural gas to a midstream processing entity at the wellhead or the inlet of the midstream processing entity's system. The midstream processing entity gathers and processes the natural gas and remits proceeds to the Company for the resulting sales of NGL and residue gas. In these scenarios, we evaluate whether we are the principal or the agent in the transaction, and the point at which control of the hydrocarbons transfer to the customer. For those contracts where the Company has concluded the midstream processing entity is the Company's agent and the third-party end user is its customer (generally the Company's fixed-fee gathering and processing agreements), the Company recognizes revenue on a gross basis, with transportation and gathering expense presented as an operating expense in the consolidated statements of operations. Alternatively, for those contracts where the Company has concluded the midstream processing entity is its customer and controls the hydrocarbons (generally the Company's percentage of proceeds gathering and processing agreements), the Company recognizes natural gas and NGL revenues based on the net amount of the proceeds received from the midstream processing company.

In certain natural gas processing agreements, the Company may elect to take its residue gas and/or NGL in-kind at the tailgate of the midstream entity's processing plant and subsequently market the product. Through the marketing process, the Company delivers product to the third-party purchaser at a contractually agreed-upon delivery point and receives a specified index price from the purchaser. In this scenario, the Company recognizes revenue when the control transfers to the purchaser at the delivery point based on the index price received from the purchaser. The gathering and processing expense attributable to the gas processing contracts, as well as any transportation expense incurred to deliver the product to the purchaser, are presented as transportation and gathering expense in the consolidated statements of operations.

Performance Obligations

A significant number of the Company's product sales are short-term in nature with a contract term of one year or less. For those contracts, the Company has utilized the practical expedient in ASC 606-10-50-14 exempting the Company from disclosure of the transaction price of a contract that has an original expected duration of one year or less.

For the Company's product sales that have a contract term greater than one year, the Company has utilized the practical expedient in ASC 606-10-50-14(a), which states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

The Company records revenue on its oil, natural gas and NGL sales at the time production is delivered to the purchaser. However, settlement statements for certain oil, natural gas and NGL sales may not be received for 30 to 90 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production delivered to the customer and the net commodity price that will be received for the sale of these commodity products. The Company records the differences between the revenue estimated and the actual amounts received for product sales in the month that payment is received from the customer. The Company has internal controls over its revenue estimation process and related accruals, and any identified differences between its revenue estimates and actual revenue received historically have not been significant. For the period from January 1, 2018 to September 30, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

Contract Balances

Under the Company's various sales contracts, the Company invoices customers once its performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Company's product sales contracts do not give rise to contract assets or liabilities under ASC 606.

The following table presents the Company's revenues disaggregated by revenue source. Transportation and gathering costs in the following table are not all of the transportation and gathering expenses that the Company incurs, only the expenses that are netted against revenues pursuant to ASC 606. Prior period amounts have not been adjusted under the modified retrospective method.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2018	**2017**	**2018**	**2017**
Revenues:				
Oil sales	$ 225,467	$ 132,075	$ 619,211	$ 269,597
Natural gas sales	26,394	24,672	76,492	63,095
NGL sales	39,154	24,114	101,349	57,574
Transportation and gathering included in revenues	(8,855)	—	(24,481)	—
Total Revenues	$ 282,160	$ 180,861	$ 772,571	$ 390,266

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 consolidated 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 and Divestitures

August 2018 Divestiture

On August 3, 2018, Elevation received proceeds of $83.6 million and recognized a gain of $83.6 million for the three and nine months ended September 30, 2018, upon the sale of assets of DJ Holdings, LLC, a subsidiary of Discovery Midstream Partners, LP, of which Elevation held a 10% membership interest. The Company acquired its interest in exchange for the contribution of an acreage dedication, which is considered a nonfinancial asset.

April 2018 Divestitures

In April 2018, the Company completed various sales of its interests in approximately 15,100 net acres of leasehold and primarily non-producing properties for aggregate sales proceeds of approximately $72.3 million and recognized a gain of $59.9 million for the three and nine months ended September 30, 2018.

April 2018 Acquisition

On April 19, 2018, the Company acquired an unaffiliated oil and gas company's interest in approximately 1,000 net acres of non-producing leasehold primarily located in Arapahoe County, Colorado, (the "April 2018 Acquisition"). Upon closing the seller received approximately $9.4 million in cash. This transaction has been accounted for as an asset acquisition. The acquisition provided new development opportunities in the Core DJ Basin.

January 2018 Acquisition

On January 8, 2018, the Company acquired an unaffiliated oil and gas company's interest in approximately 1,200 net acres of non-producing leasehold located in Arapahoe County, Colorado, (the "January 2018 Acquisition"). Upon closing the seller received approximately $11.6 million in cash. This transaction has been accounted for as an asset acquisition. The acquisition provided new development opportunities in the Core DJ Basin.

November 2017 Acquisition

On November 15, 2017, the Company acquired an unaffiliated oil and gas company's interest in approximately 36,600 net acres of leasehold and primarily non-producing properties located in Arapahoe County, Colorado, (the "November 2017 Acquisition"). Upon closing the seller received $214.3 million in cash, subject to customary purchase price adjustments. The Company also paid $12.2 million for the final settlement payment in April 2018 in conjunction with the November 2017 Acquisition. This transaction has been accounted for as an asset acquisition. The acquisition provided new development opportunities in the Core DJ Basin.

July 2017 Acquisition

On July 7, 2017, the Company acquired an unaffiliated oil and gas company's interests in approximately 12,500 net acres of leasehold, and primarily non-producing properties and producing properties located primarily in Adams County, Colorado, along with various other related rights, permits, contracts, equipment, rights of way, gathering systems and other assets (the "July 2017 Acquisition"). Upon closing the seller received total consideration of $84.0 million in cash, subject to customary purchase price adjustments. The effective date for the July 2017 Acquisition is July 1, 2017. This transaction has been accounted for as an asset acquisition. The acquisition provided new development opportunities in the Core DJ Basin.

June 2017 Acquisition

On June 8, 2017, the Company acquired an unaffiliated oil and gas company's interests in approximately 160 net acres of leasehold and related producing properties located in Weld County, Colorado (the "June 2017 Acquisition"). The Company paid approximately $13.4 million in cash consideration in connection with the closing of the June 2017 Acquisition. The effective date for the acquisition was January 1, 2017, with purchase price adjustments calculated as of the closing date of June 8, 2017. The acquisition increased the Company's interest in existing operated wells. The acquired producing properties contributed $0.8 million and $2.6 million of revenue and $0.6 million and $2.0 million of earnings, respectively, for three and nine months ended September 30, 2018. The acquired producing properties contributed $1.5 million and $2.2 million of revenue and $1.1 million and $1.7 million of earnings, respectively, for the three and nine months ended September 30, 2017.

No significant transaction costs related to the acquisition were incurred for the three and nine months ended September 30, 2018 and 2017.

The June 2017 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 June 8, 2017. In August 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		**June 8, 2017**
Consideration given		
Cash	$	13,395
Total consideration given	$	13,395
Allocation of Purchase Price		
Proved oil and gas properties	$	13,495
Total fair value of oil and gas properties acquired	$	13,495
Asset retirement obligations	$	(100)
Fair value of net assets acquired	$	13,395

Pro Forma Financial Information (Unaudited)

For the three and nine months ended September 30, 2017, the following pro forma financial information represents the combined results for the Company and the properties acquired in the June 2017 Acquisition as if the acquisition had occurred on January 1, 2017. The June 2017 Acquisition has no impact on the historical results of the Company for the three and nine months ended September 30, 2018. For purposes of pro forma financial information, it was assumed that the June 2017 Acquisition was funded through cash. For the three and nine months ended September 30, 2017, the pro forma financial information includes effects of adjustments for DD&A expense of $1.6 million and income tax expense of $0.6 million.

The following pro forma results (in thousands, except per share data) 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. Asset acquisitions are not included in pro forma financial information, as it is not required. The pro forma results are not necessarily indicative of what actually would have occurred if the acquisition had been completed as of the beginning of the period, nor are they necessarily indicative of future results.

		For the Three Months Ended September 30,		**For the Nine Months Ended September 30,**
		2017		**2017**
Revenues	$	180,861	$	392,430
Operating expenses	$	175,699	$	427,912
Net loss	$	(29,796)	$	(13,663)
Loss per common share, basic and diluted	$	(0.20)	$	(0.15)

Note 4—Long-Term Debt

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

	September 30, 2018	December 31, 2017
Credit facility due August 16, 2022 (or an earlier time as set forth in the credit facility)	$ 290,000	$ 90,000
2021 Senior Notes due July 15, 2021	—	550,000
2024 Senior Notes due May 15, 2024	400,000	400,000
2026 Senior Notes due February 1, 2026	750,000	—
Unamortized debt issuance costs on Senior Notes	(17,885)	(16,639)
Total long-term debt	1,422,115	1,023,361
Less: current portion of long-term debt	—	—
Total long-term debt, net of current portion	$ 1,422,115	$ 1,023,361

Credit Facility

In August 2017, the Company entered into an amendment and restatement of its existing credit facility (prior to amendment and restatement, the "Prior Credit Facility"), to provide aggregate commitments of $1.5 billion with a syndicate of banks, which is subject to a borrowing base. The credit facility matures on the earlier of (a) August 16, 2022, (b) April 15, 2021, if (and only if) (i) the Series A Preferred Stock of the Company (the "Series A Preferred Stock") have not been converted into common equity or redeemed prior to April 15, 2021, and (ii) prior to April 15, 2021, the maturity date of the Series A Preferred Stock has not been extended to a date that is no earlier than six months after August 16, 2022 or (c) the earlier termination in whole of the commitments. No principal payments are generally required until the credit agreement matures or in the event that the borrowing base falls below the outstanding balance.

In January 2018, the Company amended its revolving credit facility to (i) increase the borrowing base from $525.0 million to $750.0 million, subject to the current elected commitments of $650.0 million, (ii) increase the maximum amount for the letter of credit issued in favor of a purchaser of its crude oil from $25.0 million to $35.0 million, and (iii) amend certain provisions of the credit agreement, including the commitments and allocations of each lender. In connection with the 2026 Senior Notes Offering (as defined below), the borrowing base was automatically reduced to $700.0 million; however, the current elected commitments remained at $650.0 million.

In February 2018, the Company entered into a consent agreement and amended its revolving credit facility to (i) provide for consent by the lenders to (a) the designation of Elevation Midstream, LLC as an unrestricted subsidiary and (b) the transfer of certain assets by the Company and one of the guarantors to such unrestricted subsidiary; and (ii) amend certain provisions of the credit agreement, including the incurrence of indebtedness covenant to permit certain indebtedness in connection with certain transportation service agreements with such unrestricted subsidiary.

In May 2018, the Company amended its revolving credit facility to (i) increase the borrowing base from $700.0 million to $800.0 million, subject to current elected commitments of $650.0 million and (ii) reduce each of the applicable interest rate margins for borrowings by 0.50%.

In October 2018, the Company amended its revolving credit facility to (i) provide the lenders consent to postpone the November 1, 2018 scheduled borrowing base redetermination until December 15, 2018 and (ii) permit the Company to make payments with respect to its own equity, subject to certain terms, conditions and financial thresholds.

As of September 30, 2018, the credit facility was subject to a borrowing base of $800.0 million, subject to current elected commitments of $650.0 million. As of September 30, 2018 and, with respect to the Prior Credit Facility, December 31, 2017, the Company had outstanding borrowings of $290.0 million and $90.0 million, respectively. As of September 30, 2018 and, with respect to the Prior Credit Facility, December 31, 2017, the Company had standby letters of credit of $35.7 million and $25.7 million, respectively. At September 30, 2018, the undrawn balance under the credit facility was $360.0 million. As of the date of this filing, the Company has $240.0 million borrowings outstanding under the credit facility.

The amount available to be borrowed under the Company's revolving credit facility is subject to a borrowing base that is redetermined semiannually on each May 1 and November 1 (except that the November 1, 2018 redetermination was postponed to December 15, 2018 with the consent of the lenders), and will depend on the volumes of the Company's proved oil and gas reserves and estimated cash flows from these reserves and other information deemed relevant by the administrative agent under the Company's revolving credit facility.

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	Eurodollar Margin	Base Rate Margin	Commitment Fee Rate
Level 1	< 25%	1.50%	0.50%	0.375%
Level 2	≥ 25% < 50%	1.75%	0.75%	0.375%
Level 3	≥ 50% < 75%	2.00%	1.00%	0.500%
Level 4	≥ 75% < 90%	2.25%	1.25%	0.500%
Level 5	≥ 90%	2.50%	1.50%	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; and (iv) limitations on the sale of property, mergers, consolidations and other similar transactions covenants. 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 its consolidated current assets (includes availability under the revolving credit facility and unrestricted cash and excludes derivative assets) to its consolidated current liabilities (excludes obligations under the 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 to its consolidated EBITDAX (EBITDAX is defined as net income adjusted for certain cash and non-cash items including DD&A, 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. The Company was in compliance with all financial covenants under the credit facility as of September 30, 2018 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 certain of its subsidiaries, including oil and gas properties, personal property and the equity interests of those subsidiaries. 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. Elevation is a separate entity and the assets and credit of Elevation are not available to satisfy the debts and other obligations of the Company or its other subsidiaries. As of September 30, 2018, $182.0 million of cash was held by Elevation and is earmarked for construction of pipeline infrastructure to serve the development of acreage in its Hawkeye and Southwest Wattenberg areas.

2021 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 "2021 Senior Notes" and the offering, the "2021 Senior Notes Offering"). The 2021 Senior Notes bore an annual interest rate of 7.875%. The interest on the 2021 Senior Notes was 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.

Concurrent with the 2026 Senior Notes Offering (as defined below), the Company commenced a cash tender offer to purchase any and all of its 2021 Senior Notes. On January 24, 2018, the Company received approximately $500.6 million aggregate principal amount of the 2021 Senior Notes which were validly tendered (and not validly withdrawn). As a result, on January 25, 2018, the Company made a cash payment of approximately $534.2 million, which includes a principal of approximately $500.6 million, a make-whole premium of approximately $32.6 million and accrued and unpaid interest of approximately $1.0 million.

On February 17, 2018, the Company redeemed approximately $49.4 million aggregate principal amount of the 2021 Senior Notes that remained outstanding after the Tender Offer and made a cash payment of approximately $52.7 million to the remaining holders of the 2021 Senior Notes, which included a make-whole premium of $3.0 million and accrued and unpaid interest of approximately $0.3 million.

2024 Senior Notes

In August 2017, the Company issued at par $400.0 million principal amount of 7.375% Senior Notes due May 15, 2024 (the “2024 Senior Notes” and the offering, the “2024 Senior Notes Offering”). The 2024 Senior Notes bear an annual interest rate of 7.375%. The interest on the 2024 Senior Notes is payable on May 15 and November 15 of each year which commenced on November 15, 2017. The Company received net proceeds of approximately $392.6 million after deducting fees.

The Company's 2024 Senior Notes are its senior unsecured obligations and rank equally in right of payment with all of its other senior indebtedness and senior to any of its subordinated indebtedness. The Company's 2024 Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by certain of the Company's current subsidiaries and by certain future restricted subsidiaries that guarantees its indebtedness under a credit facility (the “2024 Senior Note Guarantors”). The notes are effectively subordinated to all of the Company's secured indebtedness (including all borrowings and other obligations under its 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 of its future subsidiaries that do not guarantee the notes.

The 2024 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 2024 Senior Notes (the “2024 Senior Notes Indenture”) also contains customary events of default. Upon the occurrence of events of default arising from certain events of bankruptcy or insolvency, the 2024 Senior Notes shall become due and payable immediately without any declaration or other act of the trustee or the holders of the 2024 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 2024 Senior Notes may declare all outstanding 2024 Senior Notes to be due and payable immediately.

2026 Senior Notes

In January 2018, the Company issued at par $750.0 million principal amount of 5.625% Senior Notes due February 1, 2026 (the “2026 Senior Notes” and the offering, the “2026 Senior Notes Offering”). The 2026 Senior Notes bear an annual interest rate of 5.625%. The interest on the 2026 Senior Notes is payable on February 1 and August 1 of each year commencing on August 1, 2018. The Company received net proceeds of approximately $737.9 million after deducting fees. The Company used $534.2 million of the net proceeds from the 2026 Senior Notes Offering to fund the tender offer for its 2021 Senior Notes, $52.7 million to redeem any 2021 Senior Notes not tendered and the remainder for general corporate purposes.

The Company's 2026 Senior Notes are the Company's senior unsecured obligations and rank equally in right of payment with all of the Company's other senior indebtedness and senior to any of the Company's subordinated indebtedness. The Company's 2026 Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by certain of the Company's current subsidiaries and by certain future restricted subsidiaries that guarantee the Company's indebtedness under a credit facility. The 2026 Senior Notes are effectively subordinated to all of the Company's secured indebtedness (including all borrowings and other obligations under the Company's 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 certain of the Company's future restricted subsidiaries that do not guarantee the 2026 Senior Notes.

The 2026 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 2026 Senior Notes (the “2026 Senior Notes Indenture”) also contains customary events of default. Upon the occurrence of events of default arising from certain events of bankruptcy or insolvency, the 2026 Senior Notes shall become due and payable immediately without any declaration or other act of the trustee or the holders of the 2026 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 2026 Senior Notes may declare all outstanding 2026 Senior Notes to be due and payable immediately.

Debt Issuance Costs

As of September 30, 2018, the Company had debt issuance costs, net of accumulated amortization, of $3.7 million related to its credit facility which has been reflected on the Company’s balance sheet within the line item other non-current assets. As of September 30, 2018, the Company had debt issuance costs, net of accumulated amortization, of $17.9 million related to its 2024 and 2026 Senior Notes (collectively, the "Senior Notes") which has been reflected on the Company's consolidated 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 and nine months ended September 30, 2018, the Company recorded amortization expense related to debt issuance costs of $0.9 million and $12.3 million, respectively, as compared to $1.5 million and $3.2 million for the three and nine months ended September 30, 2017, respectively. Debt issuance costs for the nine months ended September 30, 2018 include $9.4 million of acceleration of amortization expense upon the repayment of the Company's 2021 Senior Notes. The repayment of the Company's 2021 Senior Notes had no impact to amortization expense for the three months ended September 30, 2018.

Interest Incurred on Long-Term Debt

For the three and nine months ended September 30, 2018, the Company incurred interest expense on long-term debt of $21.5 million and $61.6 million, respectively, as compared to $16.5 million and $39.2 million for the three and nine months ended September 30, 2017, respectively. For the three and nine months ended September 30, 2018, the Company capitalized interest expense on long term debt of $1.7 million and $6.3 million, respectively, as compared to $2.9 million and $8.6 million for the three and nine months ended September 30, 2017, respectively, which has been reflected in the Company’s condensed consolidated financial statements. Also included in interest expense for the nine months ended September 30, 2018 is a make-whole premium of $35.6 million related to the Company's repayment of its 2021 Senior Notes in January and February 2018. The repayment of the Company's 2021 Senior Notes had no impact to interest expense for the three months ended September 30, 2018.

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

The Company's commodity derivative contracts as of September 30, 2018 are summarized below:

	2018	2019
NYMEX WTI Crude Swaps:		
Notional volume (Bbl)	1,050,000	—
Weighted average fixed price ($/Bbl)	$ 52.91	$ —
NYMEX WTI Crude Purchased Puts:		
Notional volume (Bbl)	2,250,000	9,300,000
Weighted average purchased put price ($/Bbl)	$ 49.81	$ 51.44
NYMEX WTI Crude Sold Calls:		
Notional volume (Bbl)	2,250,000	9,300,000
Weighted average sold call price ($/Bbl)	$ 58.33	$ 64.78
NYMEX WTI Crude Sold Puts:		
Notional volume (Bbl)	3,300,000	8,700,000
Weighted average sold put price ($/Bbl)	$ 40.00	$ 41.69
NYMEX HH Natural Gas Swaps:		
Notional volume (MMBtu)	9,900,000	25,800,000
Weighted average fixed price ($/MMBtu)	$ 3.02	$ 2.77
NYMEX HH Natural Gas Purchased Puts:		
Notional volume (MMBtu)	600,000	3,000,000
Weighted average purchased put price ($/MMBtu)	$ 3.00	$ 2.99
NYMEX HH Natural Gas Sold Calls:		
Notional volume (MMBtu)	600,000	3,000,000
Weighted average sold call price ($/MMBtu)	$ 3.15	$ 3.36
NYMEX HH Natural Gas Sold Puts:		
Notional volume (MMBtu)	—	3,000,000
Weighted average sold put price ($/MMBtu)	$ —	$ 2.50
CIG Basis Gas Swaps:		
Notional volume (MMBtu)	11,040,000	31,200,000
Weighted average fixed basis price ($/MMBtu)	$ (0.68)	$ (0.75)

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 condensed consolidated balance sheets (in thousands):

	As of September 30, 2018				
Location on Balance Sheet	**Gross Amounts of Recognized Assets and Liabilities**	**Gross Amounts Offsets 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	$ 92,161	$ (78,935)	$ 13,226	$ (2,145)	$ 11,081
Non-current assets	$ 7,085	$ (7,085)	$ —	$ —	$ —
Current liabilities	$ (222,511)	$ 78,935	$ (143,576)	$ 2,145	$ (150,217)
Non-current liabilities	$ (15,871)	$ 7,085	$ (8,786)	$ —	$ —

	As of December 31, 2017				
Location on Balance Sheet	**Gross Amounts of Recognized Assets and Liabilities**	**Gross Amounts Offsets 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	$ 22,118	$ (17,986)	$ 4,132	$ —	$ 4,132
Non-current assets	$ 13,686	$ (13,686)	$ —	$ —	$ —
Current liabilities	$ (85,414)	$ 17,986	$ (67,428)	$ —	$ (84,702)
Non-current liabilities	$ (30,960)	$ 13,686	$ (17,274)	$ —	$ —

(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 condensed 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 and nine months ended September 30, 2018 and 2017 (in thousands). Commodity derivatives gain (loss) is included under the other income (expense) line item in the condensed consolidated statements of operations.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2018	**2017**	**2018**	**2017**
Commodity derivatives gain (loss)	$ (35,913)	$ (37,875)	$ (175,752)	$ 46,423

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 Nine Months Ended September 30, 2018	For the Year Ended December 31, 2017
Balance beginning of period	$ 69,540	$ 56,108
Liabilities incurred or acquired	1,705	9,802
Liabilities settled	(9,581)	(4,169)
Revisions in estimated cash flows	3,698	2,630
Accretion expense	3,989	5,169
Balance end of period	$ 69,351	$ 69,540

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 September 30, 2018 and December 31, 2017 by level within the fair value hierarchy (in thousands):

	Fair Value Measurements at September 30, 2018 Using			
	Level 1	Level 2	Level 3	Total
Financial Assets:				
Commodity derivative assets	$ —	$ 13,226	$ —	$ 13,226
Financial Liabilities:				
Commodity derivative liabilities	$ —	$ 152,362	$ —	$ 152,362

	Fair Value Measurements at December 31, 2017 Using			
	Level 1	Level 2	Level 3	Total
Financial Assets:				
Commodity derivative assets	$ —	$ 4,132	$ —	$ 4,132
Financial Liabilities:				
Commodity derivative liabilities	$ —	$ 84,702	$ —	$ 84,702

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 values of the 2021 Senior Notes, 2024 Senior Notes and 2026 Senior Notes were derived from available market data. As such, the Company has classified the 2021 Senior Notes, 2024 Senior Notes and 2026 Senior Notes as Level 2. Please refer to *Note 4 - Long-Term Debt* for further information. The Company's policy is to recognize transfers between levels at the end of the period. This disclosure (in thousands) does not impact the Company's financial position, results of operations or cash flows.

	At September 30, 2018		At December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Credit Facility	$ 290,000	$ 290,000	$ 90,000	$ 90,000
2021 Senior Notes(1)	$ —	$ —	$ 540,382	$ 583,000
2024 Senior Notes(2)	$ 393,638	$ 393,520	$ 392,979	$ 427,000
2026 Senior Notes(3)	$ 738,477	$ 667,500	$ —	$ —

(1) The carrying amount of the 2021 Senior Notes includes unamortized debt issuance costs of $9.6 million as of December 31, 2017. There were no unamortized debt issuance costs as of September 30, 2018.

(2) The carrying amount of the 2024 Senior Notes includes unamortized debt issuance costs of $6.4 million and $7.0 million as of September 30, 2018 and December 31, 2017, respectively.

(3) The carrying amount of the 2026 Senior Notes includes unamortized debt issuance costs of $11.5 million as of September 30, 2018. There were no unamortized debt issuance costs as of December 31, 2017.

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, and at least annually, 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 and 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). For the three and nine months ended September 30, 2018, the Company recognized $16.2 million in impairment expense on its proved oil and gas properties related to impairment of assets in its northern field. The fair value did not exceed the Company's carrying amount associated with its proved oil and gas properties in its northern field. No impairment expense was recognized for the three and nine months ended September 30, 2017 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 fair 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 its core DJ Basin field. If indicators of impairment are determined to exist, an impairment charge is recognized if the carrying value of goodwill exceeds its implied fair value. 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 uses an income approach analysis based on the net discounted future cash flows of producing property utilizing market participant inputs. 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 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). The Company performed a quantitative assessment as of September 30, 2018, which concluded the fair value of the reporting unit was 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 and Divestitures*. 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 items recorded during the interim period. The computation of the annual estimated effective tax rate at each interim period requires certain estimates and significant judgment including, but not limited to, the expected operating income (loss) for the year, projections of the proportion of income earned and taxed in various jurisdictions, permanent 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 for the nine months ended September 30, 2018 was 35.9%. During the nine months ended September 30, 2018, the Company recognized income tax expense of $12.3 million. The effective rate for the nine months ended September 30, 2018 differs from the statutory U.S. federal income tax rate of 21.0% primarily due to state income taxes and estimated permanent differences. The most significant difference during the nine months ended September 30, 2018 was a discrete item regarding the tax deficiency of the stock-based compensation compared to the compensation recognized for financial reporting purposes. The Company anticipates the potential for increased periodic volatility in future effective tax rates from the impact of stock-based compensation tax deductions as they are treated as discrete tax items.

On December 22, 2017, the Tax Cut and Jobs Act (the "TCJA") was enacted, making significant changes to the Internal Revenue Code. The Company calculated its best estimate of the impact of the TCJA in its December 31, 2017 income tax provision in accordance with its understanding of the TCJA and guidance available as of the date of that filing. During the nine months ended September 30, 2018, the Company completed the accounting for the income tax effect of the TCJA's limit on compensation under Internal Revenue Code Sec. 162(m) and stock-based compensation for covered employees. This resulted in a $0.4 million reduction in deferred tax assets that had been recorded as a provisional amount as of December 31, 2017. There are no remaining provision amounts associated with the TCJA as of September 30, 2018.

Note 9—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. The Company reserved 20.2 million shares of common stock for issuance pursuant to awards under the LTIP. Extraction has granted awards under the LTIP to certain directors, officers and employees, including stock options, restricted stock units and performance stock awards.

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. As of January 1, 2017, the Company elected to account for stock-based compensation forfeitures as they occur, as a result of the adoption of ASU No. 2016-09.

The Company recorded $7.1 million and $20.7 million of stock-based compensation costs related to RSUs for the three and nine months ended September 30, 2018, respectively, as compared to $3.3 million and $9.9 million for the three and nine months ended September 30, 2017, respectively. These costs were included in the condensed consolidated statements of operations within the general and administrative expenses line item. As of September 30, 2018, there was $38.7 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 1.6 years.

The following table summarizes the RSU activity from January 1, 2018 through September 30, 2018 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, 2018	2,906,473	$ 19.51
Granted	1,121,768	$ 12.82
Forfeited	(45,150)	$ 15.91
Vested	(317,161)	$ 15.90
Non-vested RSUs at September 30, 2018	3,665,930	$ 17.80

Stock Options

Expense on the stock options is recognized on a straight-line basis over the service period of the award less awards forfeited. The fair value of the stock options was 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 $3.8 million and $11.3 million of stock-based compensation costs related to the stock options for the three and nine months ended September 30, 2018, respectively, as compared to $3.3 million and $9.9 million for the three and nine months ended September 30, 2017, respectively. These costs were included in the condensed consolidated statements of operations within the general and administrative expenses line item. As of September 30, 2018, there was $15.9

million of unrecognized compensation cost related to the stock options that is expected to be recognized over a weighted average period of 1.1 years.

The following table summarizes the stock option activity from January 1, 2018 through September 30, 2018 and provides information for stock options outstanding at the dates indicated.

	Number of Options	Weighted Average Exercise Price
Non-vested Stock Options at January 1, 2018	3,496,290	$ 18.50
Granted	—	$ —
Forfeited	—	$ —
Vested	—	$ —
Non-vested Stock Options at September 30, 2018	3,496,290	$ 18.50

Performance Stock Awards

The Company granted performance stock awards ("PSAs") to certain executives under the LTIP in October 2017 and March 2018. The number of shares of the Company's common stock that may be issued to settle PSAs ranges from zero to one times the number of PSAs awarded. Generally, the shares issued for PSAs are determined based on the satisfaction of a time-based vesting schedule and a weighting of one or more of the following: i) absolute total stockholder return ("ATSR"), ii) relative total stockholder return ("RTSR"), as compared to the Company's peer group and iii) cash return on capital invested ("CROCI") measured over a three year period and vest in their entirety at the end of the three-year measurement period. Any PSAs that have not vested at the end of the applicable measurement period are forfeited. The vesting criterion that is associated with the RTSR is based on a comparison of the Company's shareholder return for the measurement period compared to that of a group of peer companies for the same measurement period. As the ATSR and RTSR vesting criteria are linked to the Company's share price, they each are considered a market condition for purposes of calculating the grant-date fair value of the awards. The vesting criterion that is associated with the CROCI is considered a performance condition for purposes of calculating the grant-date fair value of the awards.

The fair value of the PSAs was measured at the grant date with a stochastic process method using a Monte Carlo simulation. A stochastic process is a mathematically defined equation that can create a series of outcomes over time. Those outcomes are not deterministic in nature, which means that by iterating the equations multiple times, different results will be obtained for those iterations. In the case of the Company's PSAs, the Company cannot predict with certainty the path its stock price or the stock prices of its peer will take over the performance period. By using a stochastic simulation, the Company can create multiple prospective stock pathways, statistically analyze these simulations, and ultimately make inferences regarding the most likely path the stock price will take. As such, because future stock prices are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the Monte Carlo Model, is deemed an appropriate method by which to determine the fair value of the PSAs. Significant assumptions used in this simulation include the Company's expected volatility, risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with the measurement period as well as the volatilities for each of the Company's peers.

The Company recorded $1.6 million and $4.2 million of stock-based compensation costs related to PSAs for the three and nine months ended September 30, 2018, respectively. The Company did not record any stock-based compensation related to PSAs for the three and nine months ended September 30, 2017. These costs were included in the condensed consolidated statements of operations within the general and administrative expenses line item. The outstanding and unvested shares were included in the condensed consolidated statement of stockholders' equity within the stock-based compensation line item. As of September 30, 2018, there was $10.7 million of total unrecognized compensation cost related to the unvested PSAs granted to certain executives that is expected to be recognized over a weighted average period of 2.0 years.

The following table summarizes the PSA activity from January 1, 2018 through September 30, 2018 and provides information for PSAs outstanding at the dates indicated.

	Number of Shares (1)	Weighted Average Grant Date Fair Value
Non-vested PSAs at January 1, 2018	832,163	$ 8.85
Granted	1,961,920	$ 9.06
Forfeited	—	$ —
Vested	—	$ —
Non-vested PSAs at September 30, 2018	2,794,083	$ 9.00

(1) The number of awards assumes that the associated maximum vesting condition is met at the target amount. The final number of shares of the Company's common stock issued may vary depending on the performance multiplier, which ranges from zero to one, depending on the level of satisfaction of the vesting condition.

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 vested over a three-year service period, with 25%, 25% and 50% of the units vesting in year one, two and three, respectively. On July 17, 2017, the partners of Employee Incentive amended the vesting schedule in which 25% vested immediately and the remaining Incentive RSUs vest 25%, 25% and 25% each six months thereafter, over the remaining 18-month service period. 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 of January 1, 2017, the Company elected to account for stock-based compensation forfeitures as they occur, as a result of the adoption of ASU No. 2016-09. 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 $4.9 million and $14.7 million of stock-based compensation costs related to Incentive RSUs for the three and nine months ended September 30, 2018, respectively. The Company recorded $5.9 million and $12.2 million of stock-based compensation costs related to Incentive RSUs for the three and nine months ended September 30, 2017. These costs were included in the condensed consolidated statements of operations within the general and administrative expenses line item. As of September 30, 2018, there was $5.7 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 0.3 years.

The following table summarizes the Incentive RSU activity from January 1, 2018 through September 30, 2018 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, 2018	1,496,175	$ 20.45
Granted	—	$ —
Forfeited	(41,400)	$ 20.45
Vested	(978,775)	$ 20.45
Non-vested Incentive RSUs at September 30, 2018	476,000	$ 20.45

Note 10—Earnings (Loss) Per Share

Basic earnings per share ("EPS") includes no dilution and is computed by dividing net income (loss) available to common shareholders 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 and nine months ended September 30, 2018 and 2017.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
Basic and Diluted Income (Loss) Per Share				
Net Income (Loss)	$ 65,150	$ (29,796)	$ 22,003	$ (13,840)
Less: Noncontrolling Interest	(3,305)	—	(3,305)	—
Less: Adjustment to reflect Series A Preferred Stock dividends	(2,721)	(2,721)	(8,164)	(8,164)
Less: Adjustment to reflect accretion of Series A Preferred Stock discount	(1,515)	(1,365)	(4,429)	(3,992)
Adjusted net income (loss) available to common shareholders, basic and diluted	$ 57,609	$ (33,882)	$ 6,105	$ (25,996)
Denominator:				
Weighted average common shares outstanding, basic and diluted (1) (2)	175,814	171,845	175,269	171,838
Income (Loss) Per Common Share				
Basic and diluted	$ 0.33	$ (0.20)	$ 0.03	$ (0.15)

(1) For the three months ended September 30, 2018, 347,343 dilutive restricted stock awards were excluded from the calculation above, as the impact of these awards were inconsequential to dilutive weighted average shares outstanding and dilutive EPS. Additionally, 5,244,428 common shares for stock options were excluded as they were out-of-the-money and 11,472,445 common shares associated with the assumed conversion of Series A Preferred Stock were excluded, as they would have had an anti-dilutive effect on EPS. For the nine months ended September 30, 2018, 537,706 dilutive restricted stock awards were excluded from the calculation above, as the impact of these awards were inconsequential to dilutive weighted average shares outstanding and dilutive EPS. Additionally, 5,244,428 common shares for stock options were excluded as they were out-of-the-money and 11,472,445 common shares associated with the assumed conversion of Series A Preferred Stock were excluded, as they would have had an anti-dilutive effect on EPS.

(2) For the three and nine months ended September 30, 2017, 8,552,814 potentially dilutive shares were not included in the calculation above, as they had an anti-dilutive effect on EPS, including restricted stock awards and stock options outstanding. Additionally, 11,472,445 common shares associated with the assumed conversion of Series A Preferred Stock were also excluded, as they would have had an anti-dilutive effect on EPS.

Note 11—Commitments and Contingencies

Leases

The Company leases two office spaces in Denver, Colorado, two office spaces 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 October 31, 2019, June 30, 2019 and January 31, 2022, respectively. Total rental commitments under non-cancelable leases for office space were $33.6 million at September 30, 2018. The future minimum lease payments under these non-cancelable leases are as follows: $0.8 million in 2018, $3.5 million in 2019, $3.4 million in 2020, $3.4 million in 2021, $3.4 million in 2022 and $19.1 million thereafter. Rent expense was $1.0 million and $2.7 million for the three and nine months ended September 30, 2018, respectively, as compared to $0.5 million and $1.7 million for the three and nine months ended September 30, 2017, 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 $0.4 million.

Drilling Rigs

As of September 30, 2018, the Company was subject to commitments on three drilling rigs, contracted through November 2018, February 2019 and May 2019, respectively. In the event of early termination of these contracts, the Company would be obligated to pay an aggregate amount of approximately $7.3 million as of September 30, 2018, as required under the terms of the contracts.

Delivery Commitments

As of September 30, 2018, 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. In May 2017, the Company amended its agreement with its oil marketer that requires it to sell all of its crude oil from an area of mutual interest in exchange for a make-whole provision that allows the Company to satisfy any minimum volume commitment deficiencies incurred by its oil marketer with future barrels of crude oil in excess of their minimum volume commitment through October 31, 2018. In December 2017, the Company extended the term of this agreement through October 31, 2019 and has posted a letter of credit in the amount of $35.0 million. 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 two long-term crude oil gathering commitments with an unconsolidated subsidiary, in which the Company has a minority ownership interest. The first agreement commenced in November 2016 and 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 second agreement will commence in or around July 2019 and has a term of ten years for an average of 8,000 Bbl/d in year one, 20,000 Bbl/d in year two, 35,000 Bbl/d in year three, 40,000 Bbl/d in years four through eight, 30,000 Bbl/d in year nine and 25,000 Bbl/d in year ten. The aggregate amount of estimated remaining payments under these agreements is $967.5 million.

In collaboration with several other producers and a midstream provider, on December 15, 2016 and August 7, 2017, the Company agreed to participate in expansions of natural gas gathering and processing capacity in the DJ Basin. The plan includes two new processing plants as well as the expansion of related gathering systems. The first plant commenced operations in August 2018 and the second plant is expected to be completed by mid-2019, although the exact start-up date is undetermined at this time. The Company's share of these commitments will require 51.5 and 20.6 MMcf per day, respectively, to be delivered after the plants' in-service dates for a period of seven years thereafter. The Company may be required to pay a shortfall fee for any volumes under these commitments. These contractual obligations can be reduced by the Company's proportionate share of the collective volumes delivered to the plants by other third-party incremental volumes available to the midstream provider at the new facilities that are in excess of the total commitments. The Company is also required for the first three years of each contract to guarantee a certain target profit margin on these volumes sold. Under its current drilling plans, the Company expects to meet these volume commitments.

Acquisition of Undeveloped Leasehold Acreage

The Company was party to an agreement during 2017 with an unrelated third party for which it has paid $247.6 million through September 30, 2018 to complete its leasing program of approximately 38,800 net acres of undeveloped leasehold.

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

From time to time, the Company is party to ongoing legal proceedings in the ordinary course of business. While the outcome of these proceedings cannot be predicted with certainty, the Company does not believe the results of these proceedings, individually or in the aggregate, will have a material adverse effect on the Company's business, financial condition, results of operations or liquidity.

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.

2021 Senior Notes

Several 5% stockholders of the Company were also holders of the 2021 Senior Notes prior to the Tender Offer and the redemption of the 2021 Senior Notes. As of the initial issuance in July 2016 of the $550.0 million principal amount on the 2021 Senior Notes, such stockholders held $63.5 million.

2024 Senior Notes

Several holders of the 2024 Senior Notes are also 5% stockholders of the Company. As of the initial issuance in August 2017 of the $400.0 million principal amount on the 2024 Senior Notes, such stockholders held $54.9 million.

2026 Senior Notes

Several holders of the 2026 Senior Notes are also 5% stockholders of the Company. As of the initial issuance in January 2018 of the $750.0 million principal amount on the 2026 Senior Notes, such stockholders held $56.2 million.

Increased Ownership in an Unconsolidated Subsidiary

In May 2018, the Company exercised an option to increase its ownership percentage in an unconsolidated subsidiary funded with a $35.3 million promissory note. This note was extinguished with the transfer of units to the unconsolidated subsidiary. The Company also contributed an acreage dedication and minimum volume commitment.

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;
- constraints in the DJ Basin of Colorado with respect to gathering, transportation and processing facilities and marketing;
- 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;
- drilling operations 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;
- 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 and management. 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, 2017 (our “Annual Report”) and in our other filings with the Securities Exchange Commission, which could materially affect our business, 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. Other than as set forth in this Quarterly Report, there have 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 and nine months ended September 30, 2018 and 2017.

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 and nine months ended September 30, 2018, crude oil, natural gas and NGL sales, coupled with the impact of settled derivatives, increased to $239.2 million and $667.5 million, respectively, as compared to $183.7 million and $384.3 million, respectively, in the same prior year periods due to an increase in sales volumes of 1,177 MBoe and 7,046 MBoe, respectively. The increase in crude oil, natural gas and NGL sales for the three and nine months ended September 30, 2018 as compared to the same prior year periods was also due to an increase of $2.59 and $3.62, respectively, in realized price per BOE, including settled derivatives.

For the three and nine months ended September 30, 2018, we had net income of $65.2 million and net income of $22.0 million, respectively, as compared to net loss of $29.8 million and $13.8 million for the three and nine months ended September 30, 2017, respectively. The change to net income for the three months ended September 30, 2018 from the three months ended September 30, 2017 was primarily driven by an increase in sales revenues of $101.3 million, a decrease in operating expenses of $35.7 million, which includes the gain on sale of assets of an unconsolidated subsidiary of $83.6 million. The change to net income for the nine months ended September 30, 2018 from the nine months ended September 30, 2017 was primarily driven by an increase in sales revenues of $382.3 million, partially offset by an increase in commodity derivative loss of $222.2 million and an increase in interest expense of $69.5 million, which includes a make-whole premium of $35.6 million and $9.4 million of acceleration of amortization expense upon the redemption of the Company's 2021 Senior Notes.

Adjusted EBITDAX was $169.4 million and $463.5 million for the three and nine months ended September 30, 2018, respectively, as compared to $128.4 million and $245.8 million for the three and nine months ended September 30, 2017, respectively, reflecting a 31.9% and 88.6% increase, respectively. Adjusted EBITDAX is a non-GAAP financial measure. For a definition of Adjusted EBITDAX and a reconciliation to our most directly comparable financial measure calculated and presented in accordance with GAAP, please read "—Adjusted EBITDAX."

Operational Results

During the three months ended September 30, 2018, our aggregate drilling, completion, and leasehold capital expenditures, totaled $186.7 million, of which $161.0 million was drilling and completion additions and $25.7 million was leasehold and surface acreage additions. This excludes the impact of the decrease in outstanding elections of $16.1 million. In addition, Elevation Midstream, LLC, our wholly owned midstream subsidiary, incurred $37.5 million of capital expenditures during the three months ended September 30, 2018. These capital expenditures are funded entirely by the Elevation Midstream, LLC Securities Purchase Agreement. See "Recent Developments" for more information.

During the three months ended September 30, 2018, we reached total depth on 41 gross (30 net) wells with an average lateral length of approximately 9,700 feet and completed 31 gross (26 net) wells with an average lateral length of approximately 6,500 feet. We turned to sales 71 gross (61 net) wells with an average lateral length of approximately 9,600 feet. We completed 1,091 total fracturing stages during the quarter while pumping approximately 340 million pounds of proppant.

Recent Developments

Proposition 112

On November 6, 2018, registered voters in the State of Colorado cast their ballots which includes Proposition 112 ("Prop. 112"). Prop. 112 would create a rigid 2,500-foot setback from oil and gas facilities to the nearest occupied structure and other "vulnerable areas," which include parks, ball fields, open space, streams, lakes and intermittent streams. It would dramatically increase the amount of surface area off-limits to new energy development by 26 times, and it would put 94 percent of private land in the top 5 oil and gas producing counties in the State of Colorado off-limits to new development. If Prop. 112 were to pass and make it to the Colorado State Statutes, we would likely encounter updates to our long-term forecast which could negatively impact future operating cash flows, credit facility re-determinations, minimum volume commitments and lead to potential non-cash impairments. We continue to monitor the regulatory environment and look at strategic alternatives to the extent Prop. 112 passes.

October 2018 Credit Facility Amendment

On October 2, 2018, we amended our revolving credit facility to (i) provide the lenders consent to postpone the November 1, 2018 scheduled borrowing base determination until December 15, 2018 and (ii) permit us to make payments with respect to our own equity, subject to certain terms, conditions and financial thresholds.

August 2018 Divestiture

On August 3, 2018, Elevation Midstream, LLC ("Elevation"), a Delaware limited liability company and subsidiary of the Company, received proceeds of $83.6 million and recognized a gain of $83.6 million for the three and nine months ended September 30, 2018, upon the sale of assets of DJ Holdings, LLC, a subsidiary of Discovery Midstream Partners, LP, of which Elevation held a 10% membership interest. We acquired its interest in exchange for the contribution of an acreage dedication, which is considered a nonfinancial asset.

Elevation Midstream, LLC Securities Purchase Agreement

On July 3, 2018, Elevation entered into a securities purchase agreement (the "Securities Purchase Agreement") with a third party (the "Purchaser"), pursuant to which Elevation agreed to sell 150,000 Preferred Units (the "Elevation Preferred Units") of Elevation at a price of $990 per Elevation Preferred Unit with an aggregate liquidation preference of $150.0 million (the "Private Placement"), in a transaction exempt from the registration requirements under the Securities Act of 1933, as amended (the "Securities Act"). The Private Placement closed on July 3, 2018 (the "Closing Date") and resulted in net proceeds of approximately $141.9 million, $25.4 million of which was a reimbursement for previously incurred midstream capital expenditures and general and administrative expenses. These Preferred Units are non-recourse to Extraction represent the noncontrolling interest presented on the condensed consolidated statement of changes in stockholders' equity.

During the twenty-eight months following the Closing Date (the "Commitment Period"), subject to the satisfaction of certain financial and operational metrics and certain other customary closing conditions, Elevation has the right to require the Purchaser to purchase additional Elevation Preferred Units on the terms set forth in the Securities Purchase Agreement. Elevation may require the Purchaser to purchase additional Elevation Preferred Units, in increments of at least $25.0 million, up to an aggregate amount of $350.0 million. During the Commitment Period, Elevation is required to pay the Purchaser a quarterly commitment fee payable in cash or in kind of 1.0% per annum on any undrawn amounts of such additional $350.0 million commitment.

As part of the transaction, Extraction also committed to Elevation that it would drill at least 425 wells in the acreage dedicated to Elevation by December 21, 2023, subject to reduction if Extraction does not sell the full amount of additional Elevation Preferred Units to the Purchaser. By way of comparison, Extraction plans to drill a total of approximately 170 wells during 2018.

The Elevation Preferred Units will entitle the Purchaser to receive quarterly dividends at a rate of 8.0% per annum (the "Dividend"). In respect of quarters ending prior to and including June 30, 2020, the Dividend is payable in cash or in kind at the election of Elevation. After June 30, 2020, the Dividend is payable solely in cash.

May 2018 Credit Facility Amendment

On May 23, 2018, we amended the revolving credit facility to, among other things, (i) increase the borrowing base from $700.0 million to $800.0 million, subject to current elected commitments of $650.0 million and (ii) reduce each of the applicable interest rate margins for borrowings under the credit facility by 0.50%.

April 2018 Divestitures

In April 2018, we completed various sales of our interests in approximately 15,100 net acres of leasehold and primarily non-producing properties, for aggregate sales proceeds of approximately $72.3 million, subject to customary purchase price adjustments. The majority of these assets were from our Other Rockies Area and we will continue to explore divestitures, as part of our ongoing initiative to divest of non-strategic assets.

April 2018 Acquisition

On April 19, 2018, we acquired an unaffiliated oil and gas company's interest in approximately 1,000 net acres of non-producing leasehold primarily located in Arapahoe County, Colorado, (the "April 2018 Acquisition"). Upon closing the seller received approximately $9.4 million in cash. The acquisition provided new development opportunities in the Core DJ Basin.

February 2018 Credit Facility Amendment

On February 27, 2018, we entered into a consent agreement and amended the revolving credit facility to (i) provide for consent by the lenders to (a) the designation of Elevation Midstream, LLC as an unrestricted subsidiary and (b) the transfer of certain assets by the Company and one of the guarantors to such unrestricted subsidiary; and (ii) amend certain provisions of the credit agreement, including the incurrence of indebtedness covenant to permit certain indebtedness in connection with certain transportation service agreements with such unrestricted subsidiary.

2026 Senior Notes

On January 25, 2018, we issued at par $750.0 million principal amount of 5.625% Senior Notes due February 1, 2026 (the "2026 Senior Notes" and the offering, the "2026 Senior Note Offering"). The 2026 Senior Notes bear an annual interest rate of 5.625%. The interest on the 2026 Senior Notes is payable on February 1 and August 1 of each year commencing on August 1, 2018. We received net proceeds of approximately $737.9 million after deducting discounts and fees. We used approximately $534.2 million of the net proceeds from the 2026 Senior Notes Offering to tender for our 7.875% Senior Notes due 2021 ("2021 Senior Notes"), $52.7 million to redeem any 2021 Senior Notes not tendered and the remainder was used for general corporate purposes.

Tender Offer to Purchase 2021 Senior Notes

On January 25, 2018, we announced the results of our cash tender offer to purchase any and all of the outstanding aggregate principal amount of the 2021 Senior Notes. An aggregate principal amount of $500.6 million (91%) was tendered and paid, in addition to a make-whole premium of $32.6 million and accrued and unpaid interest of $1.0 million, on January 25, 2018. On February 17, 2018, we redeemed approximately $49.4 million aggregate principal amount of the 2021 Senior Notes that remained outstanding after the Tender Offer and made a cash payment of approximately $52.7 million to the remaining holders of the 2021 Senior Notes, which included a make-whole premium of $3.0 million and accrued and unpaid interest of approximately $0.3 million.

January 2018 Credit Facility Amendment

On January 5, 2018, we amended the revolving credit facility to (i) increase the borrowing base from $525.0 million to $750.0 million, subject to the current elected commitments of $650.0 million, (ii) increase the maximum amount for the letter of credit issued in favor of a purchaser of our crude oil from $25.0 million to $35.0 million, and (iii) amend certain provisions of the credit agreement, including the commitments and allocation of each lender. In connection with the 2026 Senior Notes Offering, the borrowing base was automatically reduced to $700.0 million; however, the current elected commitments remained $650.0 million.

January 2018 Acquisition

On January 8, 2018, we acquired an unaffiliated oil and gas company's interest in approximately 1,200 net acres of non-producing leasehold located in Arapahoe County, Colorado, (the "January 2018 Acquisition"). Upon closing the seller received $11.6 million in cash. The acquisition provided new development opportunities in the Core DJ Basin.

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 September 30, 2018, our revenues were derived 80% from oil sales, 8% from natural gas sales and 12% from NGL sales. For the three months ended September 30, 2017, our revenues were derived 73% from oil sales, 14% from natural gas sales and 13% from NGL sales. For the nine months ended September 30, 2018, our revenues were derived 80% from oil sales, 9% from natural gas sales and 11% from NGL sales. For the nine months ended September 30, 2017, our revenues were derived 69% from oil sales, 16% from natural gas sales and 15% 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 September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
Oil (MBbl)	3,618	3,184	10,394	6,496
Natural gas (MMcf)	11,838	8,953	33,612	21,713
NGL (MBbl)	1,372	1,109	3,860	2,695
Total (MBoe)	6,963	5,785	19,855	12,809
Average net sales (BOE/d)	75,680	62,884	72,731	46,921

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 September 30, 2018, 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, and the subsequent increase during 2018 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 September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
Oil				
NYMEX WTI High ($/Bbl)	$ 74.14	$ 52.22	$ 74.15	$ 54.45
NYMEX WTI Low ($/Bbl)	$ 65.01	$ 44.23	$ 59.19	$ 42.53
NYMEX WTI Average ($/Bbl)	$ 69.43	$ 48.20	$ 66.79	$ 49.36
Average Realized Price ($/Bbl)	$ 62.32	$ 41.48	$ 59.58	$ 41.50
Average Realized Price, with derivative settlements ($/Bbl)	$ 50.02	$ 42.14	$ 48.23	$ 40.61
Average Realized Price as a % of Average NYMEX WTI	89.8%	86.1%	89.2%	84.1%
Differential ($/Bbl) to Average NYMEX WTI	$ (7.11)	$ (6.72)	$ (7.21)	$ (7.86)
Natural Gas				
NYMEX Henry Hub High ($/MMBtu)	$ 3.08	$ 3.15	$ 3.63	$ 3.42
NYMEX Henry Hub Low ($/MMBtu)	$ 2.72	$ 2.77	$ 2.55	$ 2.56
NYMEX Henry Hub Average ($/MMBtu)	$ 2.86	$ 2.95	$ 2.85	$ 3.05
NYMEX Henry Hub Average converted to a $/Mcf basis (factor of 1.1 to 1)	$ 3.15	$ 3.25	$ 3.14	$ 3.36
Average Realized Price ($/Mcf)	$ 1.95	$ 2.76	$ 1.99	$ 2.91
Average Realized Price, with derivative settlements ($/Mcf)	$ 2.08	$ 2.84	$ 2.37	$ 2.90
Average Realized Price as a % of Average NYMEX Henry Hub[(1)]	61.9%	84.9%	63.4%	86.6%
Differential ($/Mcf) to Average NYMEX Henry Hub	$ (1.20)	$ (0.49)	$ (1.15)	$ (0.45)
NGL				
Average Realized Price ($/Bbl)	$ 24.49	$ 21.74	$ 22.38	$ 21.36
Average Realized Price as a % of Average NYMEX WTI[(1)]	35.3%	45.1%	33.5%	43.3%
BOE				
Average Realized Price per BOE	$ 40.53	$ 31.26	$ 38.91	$ 30.47
Average Realized Price per BOE with derivative settlements	$ 34.35	$ 31.76	$ 33.62	$ 30.00

(1) As a result of the adoption of ASC 606 - Revenue from Contracts with Customers ("ASC 606") on January 1, 2018, certain costs previously classified as transportation and gathering expenses are presented on a net basis for proceeds expected to be received. See "—Historical Results of Operations and Operating Expense" for more information.

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 September 30, 2018:

	2018	2019
NYMEX WTI Crude Swaps:		
Notional volume (Bbl)	1,050,000	—
Weighted average fixed price ($/Bbl)	$ 52.91	$ —
NYMEX WTI Crude Purchased Puts:		
Notional volume (Bbl)	2,250,000	9,300,000
Weighted average purchased put price ($/Bbl)	$ 49.81	$ 51.44
NYMEX WTI Crude Sold Calls:		
Notional volume (Bbl)	2,250,000	9,300,000
Weighted average sold call price ($/Bbl)	$ 58.33	$ 64.78
NYMEX WTI Crude Sold Puts:		
Notional volume (Bbl)	3,300,000	8,700,000
Weighted average sold put price ($/Bbl)	$ 40.00	$ 41.69
NYMEX HH Natural Gas Swaps:		
Notional volume (MMBtu)	9,900,000	25,800,000
Weighted average fixed price ($/MMBtu)	$ 3.02	$ 2.77
NYMEX HH Natural Gas Purchased Puts:		
Notional volume (MMBtu)	600,000	3,000,000
Weighted average purchased put price ($/MMBtu)	$ 3.00	$ 2.99
NYMEX HH Natural Gas Sold Calls:		
Notional volume (MMBtu)	600,000	3,000,000
Weighted average sold call price ($/MMBtu)	$ 3.15	$ 3.36
NYMEX HH Natural Gas Sold Puts:		
Notional volume (MMBtu)	—	3,000,000
Weighted average sold call price ($/MMBtu)	$ —	$ 2.50
CIG Basis Gas Swaps:		
Notional volume (MMBtu)	11,040,000	31,200,000
Weighted average fixed basis price ($/MMBtu)	$ (0.68)	$ (0.75)

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

	For the Nine Months Ended September 30, 2018	For the Nine Months Ended September 30, 2017
NYMEX WTI Crude Swaps:		
Notional volume (Bbl)	4,000,000	2,275,000
Weighted average fixed price ($/Bbl)	$ 51.23	$ 45.88
NYMEX WTI Crude Purchased Puts:		
Notional volume (Bbl)	10,077,600	3,770,000
Weighted average strike price ($/Bbl)	$ 43.70	$ 46.63
NYMEX WTI Crude Purchased Calls:		
Notional volume (Bbl)	1,740,000	300,000
Weighted average strike price ($/Bbl)	$ 58.90	$ 60.83
NYMEX WTI Crude Sold Calls:		
Notional volume (Bbl)	6,730,000	3,420,000
Weighted average strike price ($/Bbl)	$ 57.14	$ 55.28
NYMEX WTI Crude Sold Puts:		
Notional volume (Bbl)	10,088,800	4,495,000
Weighted average strike price ($/Bbl)	$ 38.80	$ 38.02
NYMEX HH Natural Gas Swaps:		
Notional volume (MMBtu)	30,750,000	18,000,000
Weighted average fixed price ($/MMBtu)	$ 3.12	$ 3.05
NYMEX HH Natural Gas Purchased Puts:		
Notional volume (MMBtu)	1,800,000	—
Weighted average fixed price ($/MMBtu)	$ 3.00	$ —
NYMEX HH Natural Gas Sold Calls:		
Notional volume (MMBtu)	1,800,000	—
Weighted average fixed price ($/MMBtu)	$ 3.15	$ —
CIG Basis Gas Swaps:		
Notional volume (MMBtu)	26,895,000	7,400,000
Weighted average fixed basis price ($/MMBtu)	$ (0.59)	$ (0.35)
Total Amounts Received/(Paid) from Settlement (in thousands)	**$ (99,914)**	**$ (6,022)**
Cash provided by (used in) changes in Accounts Receivable and Accounts Payable related to Commodity Derivatives	$ 6,432	$ (2,871)
Cash Settlements on Commodity Derivatives per Condensed Consolidated Statements of Cash Flows	**$ (93,482)**	**$ (8,893)**

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, completion and facility expenses. We are seeing increases in costs associated with equipment rental and services, related to the increase in commodity pricing during 2018.

Capital Expenditures

For the nine months ended September 30, 2018, we incurred approximately $645.8 million in capital expenditures in connection with the drilling of 122 gross (94 net) wells with an average lateral length of approximately 8,300 feet and completed 141 gross (117 net) wells with an average lateral length of approximately 7,700 feet. We turned to sales 128 gross (100 net) wells with an average lateral length of approximately 8,600 feet. In addition, we incurred approximately $83.9 million of leasehold and surface acreage additions. These capital expenditures exclude the impact of the decrease in outstanding elections of $1.2 million. In addition, Elevation Midstream, LLC, our wholly owned midstream subsidiary, incurred $57.2 million of capital expenditures during the nine months ended September 30, 2018. These capital expenditures are funded entirely by the Elevation Midstream, LLC Securities Purchase Agreement. See "—Recent Developments" for more information.

Our 2018 revised capital budget was approximately $890 million to $990 million, substantially all of which we intend to allocate to the Core DJ Basin. We intend to allocate approximately $770 million to $840 million of our 2018 capital budget to operated and non-operated drilling and completion of new wells. We expect to drill between 168 to 173 gross operated wells, complete between 170 to 175 gross operated wells and turn to sales between 163 to 168 gross operated wells. Approximately $120 million to $150 million is expected to be allocated to acreage leasing, midstream, and other capital expenditures. Our capital budget anticipates a two to three operated rig drilling program and excludes any amounts that may have been 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. For example, we are seeing increases in costs associated with casing, sand, equipment rental and services. 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, (gain) loss on sale of property and equipment and assets of unconsolidated subsidiaries, acquisition transaction expenses, (gain) loss on commodity derivatives, settlements on commodity derivative instruments, premiums paid for derivatives that settled during the period, stock-based compensation expense, amortization of debt issuance costs, make-whole premiums, 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.

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 September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
Reconciliation of Net Income (Loss) to Adjusted EBITDAX:				
Net income (loss)	$ 65,150	$ (29,796)	$ 22,003	$ (13,840)
Add back:				
Depletion, depreciation, amortization and accretion	107,315	94,220	310,296	213,483
Impairment of long lived assets	16,166	—	16,294	675
Exploration expenses	11,038	7,181	21,326	24,431
(Gain) loss on sale of property and equipment	—	—	(59,902)	451
Gain on sale of assets of unconsolidated subsidiary	(83,559)	—	(83,559)	—
Acquisition transaction expenses	—	—	—	68
(Gain) loss on commodity derivatives	35,913	37,875	175,752	(46,423)
Settlements on commodity derivative instruments	(41,009)	3,162	(99,914)	(6,022)
Premiums paid for derivatives that settled during the period	(1,956)	(293)	(5,191)	20
Stock-based compensation expense	17,420	18,110	50,883	46,707
Amortization of debt issuance costs	935	1,469	12,303	3,181
Make-whole premium on 2021 Senior Notes	—	—	35,600	—
Interest expense	19,790	13,611	55,326	30,580
Income tax expense (benefit)	22,200	(17,106)	12,300	(7,556)
Adjusted EBITDAX	$ 169,403	$ 128,433	$ 463,517	$ 245,755

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 December 22, 2017, the Tax Cut and Jobs Act ("TCJA") was enacted making significant changes to the Internal Revenue Code. We calculated our best estimate of the impact of the TCJA in our December 31, 2017 income tax provision in accordance with our understanding of the TCJA and guidance available as of the date of filing our Annual Report. Many of the provisions in the TCJA had an effective date for years beginning after December 31, 2017, including the lowering of the U.S. corporate rate from 35.0% to 21.0%. However, as a result of the enactment date of December 22, 2017, we were required to remeasure the deferred tax assets and liabilities at the rate in which they are expected to reverse. We provisionally recorded an income tax benefit in the amount of $23.4 million related to the remeasurement of the net deferred tax liability as of December 31, 2017. As of September 30, 2018, we have completed the accounting for the income tax effects of the TCJA and as such, there are no remaining provisional income tax amounts recorded.
- On January 1, 2018, the Company adopted ASC 606 - Revenue from Contracts with Customers ("ASC 606"). The Company adopted ASC 606 using the modified retrospective method to apply the new standard to all new contracts entered into on or after January 1, 2018 and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance. ASC 606 supersedes previous revenue recognition requirements in ASC 605 and includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services. See "—Critical Accounting Policies and Estimates—Adoption of ASC 606" for additional information.

- For the three and nine months ended September 30, 2018, we recognized $83.6 million and $143.5 million gain on sale of property and equipment and assets of an unconsolidated subsidiary, respectively, related to our April 2018 Divestitures and August 2018 Divestiture.

Historical Results of Operations and Operating Expenses

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
	(Unaudited)			
Revenues:				
Oil sales	$ 225,467	$ 132,075	$ 619,211	$ 269,597
Natural gas sales	23,103	24,672	66,991	63,095
NGL sales	33,590	24,114	86,369	57,574
Total Revenues	282,160	180,861	772,571	390,266
Operating Expenses:				
Lease operating expenses	20,283	15,465	61,760	41,626
Transportation and gathering	11,786	13,802	29,284	34,129
Production taxes	21,605	16,290	66,317	33,254
Exploration expenses	11,038	7,181	21,326	24,431
Depletion, depreciation, amortization and accretion	107,315	94,220	310,296	213,483
Impairment of long lived assets	16,166	—	16,294	675
(Gain) loss on sale of property and equipment and assets of unconsolidated subsidiary	(83,559)	—	(143,461)	451
Acquisition transaction expenses	—	—	—	68
General and administrative expenses	35,365	28,741	100,565	77,916
Total Operating Expenses	139,999	175,699	462,381	426,033
Operating Income (Loss)	142,161	5,162	310,190	(35,767)
Other Income (Expense):				
Commodity derivatives gain (loss)	(35,913)	(37,875)	(175,752)	46,423
Interest expense	(20,725)	(15,080)	(103,229)	(33,761)
Other income	1,827	891	3,094	1,709
Total Other Income (Expense)	(54,811)	(52,064)	(275,887)	14,371
Income (Loss) Before Income Taxes	87,350	(46,902)	34,303	(21,396)
Income tax (expense) benefit	(22,200)	17,106	(12,300)	7,556
Net Income (Loss)	$ 65,150	$ (29,796)	$ 22,003	$ (13,840)

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 September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
Sales (MBoe):	6,963	5,785	19,855	12,809
Oil sales (MBbl)	3,618	3,184	10,394	6,496
Natural gas sales (MMcf)	11,838	8,953	33,612	21,713
NGL sales (MBbl)	1,372	1,109	3,860	2,695
Sales (BOE/d):	75,680	62,884	72,731	46,921
Oil sales (Bbl/d)	39,323	34,607	38,072	23,794
Natural gas sales (Mcf/d)	128,679	97,311	123,122	79,536
NGL sales (Bbl/d)	14,910	12,059	14,138	9,871
Average sales prices(1):				
Oil sales (per Bbl)	$ 62.32	$ 41.48	$ 59.58	$ 41.50
Oil sales with derivative settlements (per Bbl)	50.02	42.14	48.23	40.61
Natural gas sales (per Mcf)(2)	1.95	2.76	1.99	2.91
Natural gas sales with derivative settlements (per Mcf)	2.08	2.84	2.37	2.90
NGL sales (per Bbl)(2)	24.49	21.74	22.38	21.36
Average price (per BOE)	40.53	31.26	38.91	30.47
Average price with derivative settlements (per BOE)	34.35	31.76	33.62	30.00
Expense per BOE:				
Lease operating expenses	$ 2.91	$ 2.67	$ 3.11	$ 3.25
Transportation and gathering(2)	1.69	2.39	1.47	2.66
Production taxes	3.10	2.82	3.34	2.60
Exploration expenses	1.59	1.24	1.07	1.91
Depletion, depreciation, amortization and accretion	15.41	16.29	15.63	16.67
Impairment of long lived assets	2.32	—	0.82	0.05
General and administrative expenses	5.08	4.97	5.06	6.08
Cash general and administrative expenses	2.58	1.84	2.50	2.43
Stock-based compensation	2.50	3.13	2.56	3.65
Total operating expenses per BOE(3)	$ 32.10	$ 30.38	$ 30.50	$ 33.22

(1) 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.

(2) As a result of the adoption of ASC 606 on January 1, 2018, certain costs previously classified as transportation and gathering expenses are presented on a net basis for proceeds expected to be received. See below for further information.

(3) Excludes (gain) loss on sale of property and equipment and acquisition transaction expenses.

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017

Oil sales revenues. Crude oil sales revenues increased by $93.4 million to $225.5 million for the three months ended September 30, 2018 as compared to crude oil sales of $132.1 million for the three months ended September 30, 2017. An increase in sales volumes between these periods contributed an $18.0 million positive impact, while an increase in crude oil prices contributed a $75.4 million positive impact.

For the three months ended September 30, 2018, our crude oil sales averaged 39.3 MBbl/d. Our crude oil sales volume increased 14% to 3,618 MBbl for the three months ended September 30, 2018 compared to 3,184 MBbl for the three months ended September 30, 2017. The volume increase is primarily due to an increase in production from the completion of 183 gross wells from October 1, 2017 to September 30, 2018, partially offset by the natural decline of our existing properties.

The average price we realized on the sale of crude oil was $62.32 per Bbl for the three months ended September 30, 2018 compared to $41.48 per Bbl for the three months ended September 30, 2017.

Natural gas sales revenues. Natural gas sales revenues decreased by $1.6 million to $23.1 million for the three months ended September 30, 2018 as compared to natural gas sales revenues of $24.7 million for the three months ended September 30, 2017. An increase in sales volumes between these periods contributed a $8.0 million positive impact, while a decrease in natural gas prices contributed a $9.6 million negative impact. The decrease in pricing is partially attributable to our adoption of ASC 606. Adoption of this new standard was applied to all new contracts entered into on or after January 1, 2018 and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance. Amounts previously recognized as transportation and gathering ("T&G") under ASC 605 of $3.3 million are currently recognized within natural gas sales revenues.

For the three months ended September 30, 2018, our natural gas sales averaged 128.7 MMcf/d. Natural gas sales volumes increased by 32% to 11,838 MMcf for the three months ended September 30, 2018 as compared to 8,953 MMcf for the three months ended September 30, 2017. The volume increase is primarily due to the completion of 183 gross wells from October 1, 2017 to September 30, 2018, partially offset by the natural decline on existing producing properties.

The average price we realized on the sale of our natural gas was $1.95 per Mcf for the three months ended September 30, 2018 compared to $2.76 per Mcf for the three months ended September 30, 2017.

NGL sales revenues. NGL sales revenues increased by $9.5 million to $33.6 million for the three months ended September 30, 2018 as compared to NGL sales revenues of $24.1 million for the three months ended September 30, 2017. An increase in sales volumes between these periods contributed a $5.7 million positive impact, while an increase in price contributed a $3.8 million positive impact. The increase in pricing is partially offset by our adoption of ASC 606. Adoption of this new standard was applied to all new contracts entered into on or after January 1, 2018 and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance. Amounts previously recognized as T&G under ASC 605 of $5.6 million are currently recognized within NGL sales revenues, offset by an increase in NGL index price.

For the three months ended September 30, 2018, our NGL sales averaged 14.9 MBbl/d. NGL sales volumes increased by 24% to 1,372 MBbl for the three months ended September 30, 2018 as compared to 1,109 MBbl for the three months ended September 30, 2017. The volume increase is primarily due to the completion of 183 gross wells from October 1, 2017 to September 30, 2018, 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 $24.49 per Bbl for the three months ended September 30, 2018 compared to $21.74 per Bbl for the three months ended September 30, 2017.

Lease operating expenses. Our LOE increased by $4.8 million to $20.3 million for the three months ended September 30, 2018, from $15.5 million for the three months ended September 30, 2017. The increase in LOE was primarily the result of an increase in producing wells and an increase in equipment rental and other service rates, partially offset by optimization of our field cost structure during the twelve months ended September 30, 2018.

On a per unit basis, LOE increased to $2.91 per BOE sold for the three months ended September 30, 2018 from $2.67 per BOE for the three months ended September 30, 2017. The increase in LOE per BOE is primarily a result of production curtailment during the three months ended September 30, 2018.

Transportation and gathering. Our T&G expense decreased by $2.0 million to $11.8 million for the three months ended September 30, 2018, from $13.8 million for the three months ended September 30, 2017. The decrease in T&G was primarily due to the adoption of ASC 606. Adoption of this new standard was applied to all new contracts entered into on or after January 1, 2018 and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance. Amounts previously recognized as T&G under ASC 605 of $8.9 million are currently recognized within natural gas and NGL sales revenues. This decrease was partially offset by an increase in producing wells and the associated residue natural gas and NGL sales volumes, resulting in $6.9 million of collectively higher T&G.

Production taxes. Our production taxes increased by $5.3 million to $21.6 million for the three months ended September 30, 2018 as compared to $16.3 million for the three months ended September 30, 2017. 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 7.7% for the three months ended September 30, 2018 as compared to 9.0% for the three months ended September 30, 2017. The decrease in production taxes as a percentage of sales revenue relates to an decrease in the estimated ad valorem and severance tax rates for the three months ended September 30, 2018.

Exploration expenses. Our exploration expenses were $11.0 million for the three months ended September 30, 2018, which were primarily attributable to $1.1 million in expense for the extension of certain leases and $9.5 million in impairment expense related to the abandonment and impairment of unproved properties for the three months ended September 30, 2018. For the three months ended September 30, 2017, we recognized $7.2 million in exploration expenses.

Depletion, depreciation, amortization and accretion expense. Our DD&A expense increased $13.1 million to $107.3 million for the three months ended September 30, 2018 as compared to $94.2 million for the three months ended September 30, 2017. This increase is due to an increase in volumes sold for the three months ended September 30, 2018 as sales increased by approximately 1,177 MBoe. On a per unit basis, DD&A expense decreased to $15.41 per BOE for the three months ended September 30, 2018 from $16.29 per BOE for the three months ended September 30, 2017.

Impairment of long lived assets. Our impairment expense of $16.2 million for the three months ended September 30, 2018 was related to impairment of the proved oil and gas properties in our northern field. The fair value did not exceed the Company's carrying amount associated with its proved oil and gas properties in its northern field. No impairment expense was recognized for the three months ended September 30, 2017.

Gain on sale of property and equipment and assets of unconsolidated subsidiary. Our gain on sale of assets of unconsolidated subsidiary was $83.6 million related to our August 2018 Divestiture for the three months ended September 30, 2018. There was no gain or loss on sale of assets of unconsolidated subsidiary for the three months ended September 30, 2017.

General and administrative expenses. General and administrative (“G&A”) expenses increased by $6.7 million to $35.4 million for the three months ended September 30, 2018 as compared to $28.7 million for the three months ended September 30, 2017. This increase is primarily due to an increase in our employee head count for the three months ended September 30, 2018 compared to the three months ended September 30, 2017. On a per unit basis, G&A expense increased to $5.08 per BOE sold for the three months ended September 30, 2018 from $4.97 per BOE sold for the three months ended September 30, 2017.

Our G&A expenses include the non-cash expense for stock-based compensation for equity awards granted to our employees and directors. For the three months ended September 30, 2018 and 2017, stock-based compensation expense was $17.4 million and $18.1 million, respectively.

Commodity derivative gain (loss). Primarily due to the increase in NYMEX crude oil futures prices at September 30, 2018 as compared to June 30, 2018 and change in fair value from the execution of new positions, we incurred a net loss on our commodity derivatives of $35.9 million for the three months ended September 30, 2018, including the amortization of premiums. Primarily due to the increase in NYMEX crude oil futures prices at September 30, 2017 as compared to June 30, 2017 and change in fair value from the execution of new positions, we incurred a net loss on our commodity derivatives of $37.9 million for the three months ended September 30, 2017, 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 in the future. Therefore, we expect our net income (loss) to reflect the volatility of commodity price forward markets. Our cash flow will only be affected upon settlement of the transactions at the current market prices at that time. During the three months ended September 30, 2018, we paid cash settlements of commodity derivatives totaling $41.0 million. During the three months ended September 30, 2017, we received cash settlements of commodity derivatives totaling $3.2 million.

Interest expense. Interest expense consists of interest expense on our long-term debt and amortization of debt issuance costs, net of capitalized interest. For the three months ended September 30, 2018, we recognized interest expense of $20.7 million as compared to $15.1 million for the three months ended September 30, 2017, as a result of borrowings under our revolving credit facility, our 2021 Senior Notes, 2024 Senior Notes, our 2026 Senior Notes and the amortization of debt issuance costs.

We incurred interest expense for the three months ended September 30, 2018 of $21.5 million related to our 2024 Senior Notes, 2026 Senior Notes, and revolving credit facility. We incurred interest expense for the three months ended September 30, 2017 of approximately $16.5 million related to our credit facility and our 2021 Senior Notes. Also included in interest expense for the three months ended September 30, 2018 and 2017 was the amortization of debt issuance costs of $0.9 million and $1.5 million, respectively. For the three months ended September 30, 2018 and 2017, we capitalized interest expense of $1.7 million and $2.9 million, respectively.

Income tax (expense) benefit. We recorded income tax expense of $22.2 million and income tax benefit of $17.1 million for the three months ended September 30, 2018 and 2017, respectively. This resulted in an effective tax rate of approximately 25.4% and 36.5% for the three months ended September 30, 2018 and 2017, respectively. The difference in effective rates for the three months ended September 30, 2018 and 2017 is primarily due to the Tax Cut and Jobs Act signed into law in December 2017, reducing the U.S. statutory rate to 21.0% from 35.0%. Our effective tax rate for the three months ended September 30, 2018 and 2017 differs from the U.S. statutory income tax rates of 21.0% and 35.0% primarily due to the effects of state income taxes and estimated taxable permanent differences.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017

Oil sales revenues. Crude oil sales revenues increased by $349.6 million to $619.2 million for the nine months ended September 30, 2018 as compared to crude oil sales of $269.6 million for the nine months ended September 30, 2017. An increase in sales volumes between these periods contributed a $161.8 million positive impact, while an increase in crude oil prices contributed a $187.8 million positive impact.

For the nine months ended September 30, 2018, our crude oil sales averaged 38.1 MBbl/d. Our crude oil sales volume increased 60% to 10,394 MBbl for the nine months ended September 30, 2018 compared to 6,496 MBbl for the nine months ended September 30, 2017. The volume increase is primarily due to an increase in production from the completion of 183 gross wells from October 1, 2017 to September 30, 2018, partially offset by the natural decline of our existing properties.

The average price we realized on the sale of crude oil was $59.58 per Bbl for the nine months ended September 30, 2018 compared to $41.50 per Bbl for the nine months ended September 30, 2017.

Natural gas sales revenues. Natural gas sales revenues increased by $3.9 million to $67.0 million for the nine months ended September 30, 2018 as compared to natural gas sales revenues of $63.1 million for the nine months ended September 30, 2017. An increase in sales volumes between these periods contributed a $34.6 million positive impact, while a decrease in natural gas prices contributed a $30.7 million negative impact. The decrease in pricing is partially attributable to our adoption of ASC 606. Adoption of this new standard was applied to all new contracts entered into on or after January 1, 2018 and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance. Amounts previously recognized as T&G under ASC 605 of $9.5 million are currently recognized within natural gas sales revenues.

For the nine months ended September 30, 2018, our natural gas sales averaged 123.1 MMcf/d. Natural gas sales volumes increased by 55% to 33,612 MMcf for the nine months ended September 30, 2018 as compared to 21,713 MMcf for the nine months ended September 30, 2017. The volume increase is primarily due to the completion of 183 gross wells from October 1, 2017 to September 30, 2018, partially offset by the natural decline on existing producing properties.

The average price we realized on the sale of our natural gas was $1.99 per Mcf for the nine months ended September 30, 2018 compared to $2.91 per Mcf for the nine months ended September 30, 2017.

NGL sales revenues. NGL sales revenues increased by $28.8 million to $86.4 million for the nine months ended September 30, 2018 as compared to NGL sales revenues of $57.6 million for the nine months ended September 30, 2017. An increase in sales volumes between these periods contributed a $24.9 million positive impact, while an increase in price contributed a $3.9 million positive impact. The increase in pricing was partially offset by our adoption of ASC 606. Adoption of this new standard was applied to all new contracts entered into on or after January 1, 2018 and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance. Amounts previously recognized as T&G under ASC 605 of $15.0 million are currently recognized within NGL sales revenues, offset by an increase in NGL index price.

For the nine months ended September 30, 2018, our NGL sales averaged 14.1 MBbl/d. NGL sales volumes increased by 43% to 3,860 MBbl for the nine months ended September 30, 2018 as compared to 2,695 MBbl for the nine months ended September 30, 2017. The volume increase is primarily due to the completion of 183 gross wells from October 1, 2017 to September 30, 2018, 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 $22.38 per Bbl for the nine months ended September 30, 2018 compared to $21.36 per Bbl for the nine months ended September 30, 2017.

Lease operating expenses. Our LOE increased by $20.2 million to $61.8 million for the nine months ended September 30, 2018, from $41.6 million for the nine months ended September 30, 2017. The increase in LOE was primarily the result of an increase in producing wells and an increase in equipment rental and other service rates, partially offset by optimization of our field cost structure during the twelve months ended September 30, 2018.

On a per unit basis, LOE decreased to $3.11 per BOE sold for the nine months ended September 30, 2018 from $3.25 per BOE sold for the nine months ended September 30, 2017. The decrease in LOE per BOE is primarily a result of flush production on several new pads turned-in-line during the nine months ended September 30, 2018.

Transportation and gathering. Our T&G expense decreased by $4.8 million to $29.3 million for the nine months ended September 30, 2018, from $34.1 million for the nine months ended September 30, 2017. The decrease in T&G is primarily attributable to adoption of ASC 606. Adoption of this new standard was applied to all new contracts entered into on or after January 1, 2018 and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance. Amounts previously recognized as T&G under ASC 605 of $24.5 million are currently recognized within natural gas and NGL sales revenues. This decrease was offset by an increase in producing wells and in both residue natural gas and NGL sales volumes, resulting in $19.7 million of collectively higher T&G.

On a per unit basis, T&G decreased to $1.47 per BOE sold for the nine months ended September 30, 2018 from $2.66 per BOE sold for the nine months ended September 30, 2017. The decrease in T&G per BOE is primarily the result of the adoption of ASC 606.

Production taxes. Our production taxes increased by $33.0 million to $66.3 million for the nine months ended September 30, 2018 as compared to $33.3 million for the nine months ended September 30, 2017. 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 8.6% for the nine months ended September 30, 2018 as compared to 8.5% for the nine months ended September 30, 2017. Production taxes as a percentage of sales revenue were consistent for the nine months ended September 30, 2018 and 2017.

Exploration expenses. Our exploration expenses were $21.3 million for the nine months ended September 30, 2018, which were primarily attributable to $4.2 million in expense for the extension of certain leases, $15.5 million in impairment expense related to the abandonment and impairment of unproved properties for the nine months ended September 30, 2018. For the nine months ended September 30, 2017, we recognized $24.4 million in exploration expenses.

Depletion, depreciation, amortization and accretion expense. Our DD&A expense increased $96.8 million to $310.3 million for the nine months ended September 30, 2018 as compared to $213.5 million for the nine months ended September 30, 2017. This increase is due to an increase in volumes sold for the nine months ended September 30, 2018 as sales increased by approximately 7,046 MBoe. On a per unit basis, DD&A expense decreased to $15.63 per BOE for the nine months ended September 30, 2018 from $16.67 per BOE for the nine months ended September 30, 2017.

Impairment of long lived assets. Our impairment expense was $16.3 million for the nine months ended September 30, 2018 was related to impairment of the proved oil and gas properties in our northern field. The fair value did not exceed the Company's carrying amount associated with its proved oil and gas properties in its northern field. Our impairment expense was $0.7 million for the nine months ended September 30, 2017.

(Gain) loss on sale of property and equipment and assets of unconsolidated subsidiary. Our gain on sale of property and equipment and assets of unconsolidated subsidiary was $143.5 million related to our April 2018 Divestitures and August 2018 Divestiture for the nine months ended September 30, 2018, as compared to a $0.5 million loss on the sale of property and equipment for the nine months ended September 30, 2017.

General and administrative expenses. G&A expenses increased by $22.7 million to $100.6 million for the nine months ended September 30, 2018 as compared to $77.9 million for the nine months ended September 30, 2017. This increase is primarily due to an increase in our employee head count for the nine months ended September 30, 2018 compared to nine months ended September 30, 2017. On a per unit basis, G&A expense decreased to $5.06 per BOE sold for the nine months ended September 30, 2018 from $6.08 per BOE sold for the nine months ended September 30, 2017.

Our G&A expenses include the non-cash expense for stock-based compensation for equity awards granted to our employees and directors. For the nine months ended September 30, 2018 and 2017, stock-based compensation expense was $50.9 million and $46.7 million, respectfully.

Commodity derivative gain (loss). Primarily due to the increase in NYMEX crude oil futures prices at September 30, 2018 as compared to December 31, 2017 and change in fair value from the execution of new positions, we incurred a net loss on our commodity derivatives of $175.8 million for the nine months ended September 30, 2018. Primarily due to the decrease in NYMEX crude oil futures prices at September 30, 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 $46.4 million for the nine months ended September 30, 2017, 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 in the future. Therefore, we expect our net income (loss) to reflect the volatility of commodity price forward markets. Our cash flow will only be affected upon settlement of the transactions at the current market prices at that time. During the nine months ended September 30, 2018 and 2017, we paid cash settlements of commodity derivatives totaling $99.9 million and $6.0 million, respectively.

Interest expense. Interest expense consists of interest expense on our long-term debt, amortization of debt issuance costs, net of capitalized interest. For the nine months ended September 30, 2018, we recognized interest expense of approximately $103.2 million as compared to $33.8 million for the nine months ended September 30, 2017, as a result of borrowings under our revolving credit facility, our 2021 Senior Notes and the associated make-whole premium upon redemption, our 2024 Senior Notes, our 2026 Senior Notes, and the amortization of debt issuance costs.

We incurred interest expense for the nine months ended September 30, 2018 of $61.6 million related to our 2021 Senior Notes, 2024 Senior Notes, 2026 Senior Notes and credit facility, as well as a make-whole premium of $35.6 million related to our repayment of our 2021 Senior Notes in January and February 2018. We incurred interest expense for the nine months ended September 30, 2017 of $39.2 million related to our credit facility and our 2021 Senior Notes and 2024 Senior Notes. Also included in interest expense for the nine months ended September 30, 2018 and 2017 was the amortization of debt issuance costs of $12.3 million and $3.2 million, respectively. Amortization expense for the nine months ended September 30, 2018 includes $9.4 million of acceleration of amortization expense upon the repayment of our 2021 Senior Notes. For the nine months ended September 30, 2018 and 2017, we capitalized interest expense of $6.3 million and $8.6 million, respectively.

Income tax (expense) benefit. We recorded income tax expense of $12.3 million and income tax benefit of $7.6 million for the nine months ended September 30, 2018 and 2017, respectively. This resulted in an effective tax rate of approximately 35.9% and 35.3% for the nine months ended September 30, 2018 and 2017, respectively. The difference in effective rates for the nine months ended September 30, 2018 and 2017 is primarily due to the Tax Cut and Jobs Act signed into law in December 2017, reducing the U.S. statutory rate to 21.0% from 35.0% and a greater tax deficiency related to equity compensation in excess of compensation recognized for financial reporting for the nine months ended September 30, 2018. Our effective tax rate for the nine months ended September 30, 2018 and 2017 differs from the U.S. statutory income tax rates of 21.0% and 35.0% primarily due to the effects of state income taxes and estimated permanent taxable differences.

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, proceeds from the offerings of our 2021 Senior Notes, 2024 Senior Notes and 2026 Senior Notes (please refer to *Note 4 - Long Term Debt)*, equity provided by investors, including our management team, cash from the IPO and Private Placement, cash from the issuance of preferred units, 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 issuance costs, were approximately $1,422.1 million and $1,023.4 million at September 30, 2018, and December 31, 2017, respectively. We also have other contractual commitments, which are described in *Note 11 – Commitments and Contingencies* in Part I, Item I, Financial Information of this 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 70% of our projected oil and natural gas 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 2024 Senior Notes, 2026 Senior Notes and credit facility and pay dividends on our Series A Preferred Stock and the Elevation Preferred Units.

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 2018 revised capital budget was approximately $890 million to $990 million, substantially all of which we intend to allocate to the Core DJ Basin. We intend to allocate approximately $770 million to $840 million of our 2018 capital budget to operated and non-operated drilling and completion of new wells. We expect to drill between 168 to 173 gross operated wells, complete between 170 to 175 gross operated wells and turn to sales between 163 to 168 gross operated wells. Approximately $120 million to $150 million is expected to be allocated to acreage leasing, midstream, and other capital expenditures. Our capital budget anticipates a two to three operated rig drilling program and excludes any amounts that may have been paid for potential acquisitions.

Cash Flows

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

	For the Nine Months Ended September 30,	
	2018	2017
Net cash provided by operating activities	$ 468,362	$ 141,736
Net cash used in investing activities	$ (678,133)	$ (1,037,262)
Net cash provided by financing activities	$ 477,068	$ 378,729

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017

Net cash provided by operating activities. For the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017, our net cash provided by operating activities increased by $326.6 million, primarily due to an increase in operating revenues, net of expenses, of $346.8 million from increased sales volumes and prices, partially offset by additional settlement payments on commodity derivatives of $84.6 million.

Net cash used in investing activities. For the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017, our net cash used in investing activities decreased by $359.1 million primarily due to a decrease of $197.2 million used in drilling and completion activities, gathering systems and facilities additions and other property and equipment additions, an increase of $83.6 million from the sale of assets of an unconsolidated subsidiary, an increase of $67.2 million from the sale of property and equipment and a decrease of $17.2 million used for the acquisition of oil and gas properties for the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017.

Net cash provided by financing activities. For the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017, our net cash provided by financing activities increased by $98.3 million, as a result of an increase of $345.7 million from the issuance of the 2026 Senior Notes, an increase of $200.0 million from the net borrowings under the credit facility, and an increase of $141.6 million from the issuance of Elevation Preferred Units, partially offset by a decrease from redemption of the 2021 Senior Notes for $585.6 million, including a make-whole premium of $35.6 million.

Working Capital

Our working capital deficit was $85.0 million and $236.7 million at September 30, 2018 and December 31, 2017, respectively. Our cash balances totaled $274.1 million and $6.8 million at September 30, 2018 and December 31, 2017, 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 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 $1.5 billion, subject to a borrowing base of $800.0 million, subject to the current elected commitments of $650.0 million, and certain of our current and future subsidiaries are or 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 2021 Senior Notes that resulted in net proceeds of approximately $537.2 million. Our 2021 Senior Notes bore interest at an annual rate of 7.875%. Interest on our 2021 Senior Notes was payable on January 15 and July 15 of each year, and the first interest payment was made on January 15, 2017. Our 2021 Senior Notes would have matured on July 15, 2021. Our 2021 Senior Notes were guaranteed by all of our current and future restricted subsidiaries (other than Extraction Finance Corp., the co-issuer of our 2021 Senior Notes). In the first quarter of 2018, we closed a tender offer for the 2021 Senior Notes and subsequently redeemed all remaining outstanding 2021 Senior Notes. No 2021 Senior Notes remain outstanding.

In August 2017, we closed a private offering of our 2024 Senior Notes that resulted in net proceeds of approximately $392.6 million. Our 2024 Senior Notes bear interest at an annual rate of 7.375%. Interest on our 2024 Senior Notes is payable on May 15 and November 15 of each year, and the first interest payment was made on November 15, 2017. Our 2024 Senior Notes will mature on May 15, 2024. Our 2024 Senior Notes are guaranteed by certain of our current subsidiaries and by certain future restricted subsidiaries that guarantee our indebtedness under a credit facility.

In January 2018, we closed a private offering of our 2026 Senior Notes that resulted in net proceeds of approximately $737.9 million. Our 2026 Senior Notes bear interest at an annual rate of 5.625%. Interest on our 2026 Senior Notes is payable on February 1 and August 1 of each year, and the first interest payment was made on August 1, 2018. Our 2026 Senior Notes will mature on February 1, 2026. Our 2026 Senior Notes are guaranteed by certain of our current subsidiaries and by certain future restricted subsidiaries that guarantee our indebtedness under a credit facility.

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 (except that the November 1, 2018 redetermination was postponed to December 15, 2018 with the consent of the lenders), 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. In January 2018, we completed the November 1, 2017 borrowing base redetermination. As a result of this redetermination, the borrowing base increased to $750.0 million and then automatically reduced to $700.0 million in connection with the issuance of the 2026 Senior Notes. In May 2018, we entered into an amendment to the credit facility which provided for an increase of the borrowing base to $800.0 million, subject to current elected commitments of $650.0 million, and reduced each of the applicable interest rate margins for borrowings under the credit facility by 0.50%.

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 150 to 250 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 50 to 150 basis points, depending on the percentage of our borrowing base utilized. As of September 30, 2018, we had $290.0 million of 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 certain of our 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;

- 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 net leverage ratio, which is the ratio of (i) consolidated debt less cash balances 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.

2021 Senior Notes

In July 2016, we closed a private offering of our 2021 Senior Notes that resulted in net proceeds of approximately $537.2 million. Our 2021 Senior Notes bore interest at an annual rate of 7.875%. Interest on our 2021 Senior Notes was payable on January 15 and July 15 of each year, and the first interest payment was made on January 15, 2017. Our 2021 Senior Notes would have matured on July 15, 2021.

Concurrent with the 2026 Senior Notes Offering, we commenced a cash tender offer to purchase any and all of our 2021 Senior Notes. On January 24, 2018 we received approximately $500.6 million aggregate principal amount of the 2021 Senior Notes which were validly tendered (and not validly withdrawn). As a result, on January 25, 2018 we made a cash payment of approximately $534.2 million, which included principal of approximately $500.6 million, a make-whole premium of approximately $32.6 million and accrued and unpaid interest of approximately $1.0 million.

On February 17, 2018, we redeemed the approximately $49.4 million aggregate principal amount of the 2021 Senior Notes that remained outstanding after the Tender Offer and made a cash payment of approximately $52.7 million to the remaining holders of the 2021 Senior Notes, which included a make-whole premium of $3.0 million and accrued and unpaid interest of approximately $0.3 million. No 2021 Senior Notes remain outstanding.

2024 Senior Notes

In August 2017, we closed a private offering of our 2024 Senior Notes that resulted in net proceeds of approximately $392.6 million. Our 2024 Senior Notes bear interest at an annual rate of 7.375%. Interest on our 2024 Senior Notes is payable on May 15 and November 15 of each year, and the first interest payment was made on November 15, 2017. Our 2024 Senior Notes will mature on May 15, 2024.

We may, at our option, redeem all or a portion of our 2024 Senior Notes at any time on or after May 15, 2020 at the redemption prices set forth in the indenture governing the 2024 Senior Notes. We are also entitled to redeem up to 35% of the aggregate principal amount of our 2024 Senior Notes before May 15, 2020, with an amount of cash not greater than the net proceeds that we raise in certain equity offerings at a redemption price equal to 107.375% of the principal amount of our 2024 Senior Notes being redeemed plus accrued and unpaid interest, if any, to the redemption date. In addition, prior to May 15, 2020, we may redeem some or all of our 2024 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 2024 Senior Notes may have the right to require us to repurchase their 2024 Senior Notes at 101% of the principal amount of the 2024 Senior Notes, plus accrued and unpaid interest, if any, to the date of purchase.

Our 2024 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 2024 Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by certain of our current subsidiaries and by certain future restricted subsidiaries that guarantee our indebtedness under a credit facility. The 2024 Senior 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 of our future subsidiaries that do not guarantee the 2024 Senior Notes.

2026 Senior Notes

On January 25, 2018, we closed a private offering of our 2026 Senior Notes that resulted in net proceeds of approximately $737.9 million. Our 2026 Senior Notes bear interest at an annual rate of 5.625%. Interest on the 2026 Senior Notes is payable on February 1 and August 1 of each year, and the first interest payment was made on August 1, 2018. Our 2026 Senior Notes will mature on February 1, 2026.

We may, at our option, redeem all or a portion of our 2026 Senior Notes at any time on or after February 1, 2021 at the redemption prices set forth in the indenture governing the 2026 Senior Notes. We are also entitled to redeem up to 35% of the aggregate principal amount of our 2026 Senior Notes before February 1, 2021, with an amount of cash not greater than the net proceeds that we raise in certain equity offerings at a redemption price equal to 105.625% of the principal amount of our 2026 Senior Notes being redeemed plus accrued and unpaid interest, if any, to the redemption date. In addition, prior to February 1, 2021, we may redeem some or all of our 2026 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 2026 Senior Notes may have the right to require us to repurchase their 2026 Senior Notes at 101% of the principal amount of the 2026 Senior Notes, plus accrued and unpaid interest, if any, to the date of purchase.

Our 2026 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 2026 Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by certain of our current subsidiaries and by certain future restricted subsidiaries that guarantee our indebtedness under a credit facility. The 2026 Senior 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 of our future subsidiaries that do not guarantee the 2026 Senior Notes.

Series A Preferred Stock

The holders of our 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 10.0% 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.

Elevation Preferred Units

On July 3, 2018, Elevation entered into the Securities Purchase Agreement with the Purchaser, pursuant to which Elevation agreed to sell 150,000 Elevation Preferred Units at a price of $990 per Elevation Preferred Unit with an aggregate liquidation preference of $150.0 million, in a transaction exempt from the registration requirements under the Securities Act. The Private Placement closed on July 3, 2018 and resulted in net proceeds of approximately $141.9 million, $25.4 million of which was a reimbursement for previously incurred midstream capital expenditures and general and administrative expenses. These Elevation Preferred Units are non-recourse to Extraction, minimizing risk to our common shareholders, and represent the noncontrolling interest presented on the condensed consolidated statement of changes in stockholders' equity. Elevation is a separate entity and the assets and credit of Elevation are not available to satisfy the debts and other obligations of the Company or its other subsidiaries. As of September 30, 2018, $182.0 million of cash was held by Elevation and is earmarked for construction of pipeline infrastructure to serve the development of acreage in its Hawkeye and Southwest Wattenberg areas.

During the Commitment Period, subject to the satisfaction of certain financial and operational metrics and certain other customary closing conditions, Elevation has the right to require the Purchaser to purchase additional Elevation Preferred Units on the terms set forth in the Securities Purchase Agreement. Elevation may require the Purchaser to purchase additional Elevation Preferred Units, in increments of at least $25.0 million, up to an aggregate amount of $350.0 million. During the

Commitment Period, Elevation is required to pay the Purchaser a quarterly commitment fee payable in cash or in kind of 1.0% per annum on any undrawn amounts of such additional $350.0 million commitment.

The Elevation Preferred Units will entitle the Purchaser to receive quarterly dividends at a rate of 8.0% per annum. In respect of quarters ending prior to and including June 30, 2020, the Dividend is payable in cash or in kind at the election of Elevation. After June 30, 2020, the Dividend is payable solely in cash.

Critical Accounting Policies and Estimates

Adoption of ASC 606

On January 1, 2018, we adopted ASC 606 - Revenue from Contracts with Customers ("ASC 606"). We adopted using the modified retrospective method to apply the new standard to all new contracts entered into on or after January 1, 2018 and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance. ASC 606 supersedes previous revenue recognition requirements in ASC 605 and includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which we expect to be entitled in exchange for those goods or services.

The impact of adoption in the current period results as follows (in thousands):

	For the Three Months Ended September 30, 2018			For the Nine Months Ended September 30, 2018		
	Under ASC 606	Under ASC 605	Change	Under ASC 606	Under ASC 605	Change
Revenues:						
Oil sales	$ 225,467	$ 225,467	$ —	$ 619,211	$ 619,211	$ —
Natural gas sales	23,103	26,394	(3,291)	66,991	76,492	(9,501)
NGL sales	33,590	39,154	(5,564)	86,369	101,349	(14,980)
Total Revenues	282,160	291,015	(8,855)	772,571	797,052	(24,481)
Operating Expenses:						
Transportation and gathering	$ 11,786	$ 20,641	$ (8,855)	$ 29,284	$ 53,765	$ (24,481)
Net Income	$ 65,150	$ 65,150	$ —	$ 22,003	$ 22,003	$ —

Changes to sales of natural gas and NGL, and transportation and gathering expenses are due to the conclusion that certain midstream processing entities are our customers in natural gas processing and marketing agreements in accordance with the five-step process in ASC 606. This is a change from previous conclusions reached for these agreements utilizing the principal versus agent indicators under ASC 605 where we determined we were the principal, the midstream processor was our agent and the third-party end user was our customer. As a result, we modified our presentation of revenues and operating expenses for these agreements. Revenues related to these agreements are now presented on a net basis for proceeds expected to be received from the midstream processing entity.

Transportation and gathering expense related to other agreements incurred prior to the transfer of control to the customer at the tailgate of the natural gas processing facilities will continue to be presented as transportation and gathering expense.

Revenues from Contracts with Customers

Sales of oil, natural gas and NGL are recognized at the point control of the commodity is transferred to the customer and collectability is reasonably assured. The majority of our contracts' pricing provisions are tied to a commodity market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of the oil or natural gas, and prevailing supply and demand conditions. As a result, the price of the oil, natural gas and NGL fluctuates to remain competitive with the other available oil, natural gas and NGL supplies.

Oil Sales

Under our crude purchase and marketing contracts, we generally sell oil production at the wellhead and collect an agreed-upon index price, net of pricing differentials. In this scenario, we recognize revenue when control transfers to the purchaser at the wellhead at the net price received.

Natural Gas and NGL Sales

Under our natural gas processing contracts, we deliver natural gas to a midstream processing entity at the wellhead or the inlet of the midstream processing entity's system. The midstream processing entity gathers and processes the natural gas and remits proceeds to us for the resulting sales of NGL and residue gas. In these scenarios, we evaluate whether we are the principal or the agent in the transaction, and the point at which control of the hydrocarbons transfer to the customer. For those contracts where we have concluded the midstream processing entity is our agent and the third-party end user is our customer (generally our fixed-fee gathering and processing agreements), we recognize revenue on a gross basis, with transportation and gathering expense presented as an operating expense in the consolidated statements of operations. Alternatively, for those contracts where we have concluded the midstream processing entity is our customer and controls the hydrocarbons (generally our percentage of proceeds gathering and processing agreements), we recognize natural gas and NGL revenues based on the net amount of the proceeds received from the midstream processing company.

In certain natural gas processing agreements, we may elect to take our residue gas and/or NGL in-kind at the tailgate of the midstream entity's processing plant and subsequently market the product. Through the marketing process, we deliver product to the third-party purchaser at a contractually agreed-upon delivery point and receive a specified index price from the purchaser. In this scenario, we recognize revenue when the control transfers to the purchaser at the delivery point based on the index price received from the purchaser. The gathering and processing expense attributable to the gas processing contracts, as well as any transportation expense incurred to deliver the product to the purchase, are presented as transportation and gathering expense in the consolidated statement of operations.

Performance Obligations

A significant number of our product sales are short-term in nature with a contract term of one year or less. For those contracts, we have utilized the practical expedient in ASC 606-10-50-14 exempting us from disclosure of the transaction price of a contract that has an original expected duration of one year or less.

For our product sales that have a contract term greater than one year, we have utilized the practical expedient in ASC 606-10-50-14(a), which states we are not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

We record revenue on our oil, natural gas and NGL sales at the time production is delivered to the purchaser. However, settlement statements for certain oil, natural gas and NGL sales may not be received for 30 to 90 days after the date production is delivered, and as a result, we are required to estimate the amount of production delivered to the customer and the net commodity price that will be received for the sale of these commodity products. We record the differences between our estimates and the actual amounts received for product sales in the month that payment is received from the customer. We have internal controls over our revenue estimation process and related accruals, and any identified differences between our revenue estimates and actual revenue received historically have not been significant. For the period from December 31, 2017 to September 30, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

Contract Balances

Under our various sales contracts, we invoice customers once our performance obligations have been satisfied, at which point payment is unconditional. Accordingly, our product sales contracts do not give rise to contract assets or liabilities under ASC 606.

The following table presents our revenues disaggregated by revenue source (in thousands). Transportation and gathering costs in the following table are not all of the transportation and gathering expenses that we incur, only the expenses that are netted against revenues pursuant to ASC 606. Prior period amounts have not been adjusted under the modified retrospective method.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2018	2017	2018	2017
Revenues:				
Oil sales	$ 225,467	$ 132,075	$ 619,211	$ 269,597
Natural gas sales	26,394	24,672	76,492	63,095
NGL sales	39,154	24,114	101,349	57,574
Transportation and gathering included in revenues	(8,855)	—	(24,481)	—
Total Revenues	$ 282,160	$ 180,861	$ 772,571	$ 390,266

There were no other changes to our critical accounting policies from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2017.

Recent Accounting Pronouncements

Please read Note 2 of the notes to the unaudited condensed consolidated financial statements included in Item 1 of this Quarterly Report for a detailed list of recent accounting pronouncements.

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 year ended December 31, 2015, commodity prices decreased, while during the years ended December 31, 2016 and 2017, commodity prices increased. During the nine months ended September 30, 2018, commodity prices increased. 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.

Off-Balance Sheet Arrangements

As of September 30, 2018, we did not have material off-balance sheet arrangements, except for our agreement with our oil marketer. 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, 2019. Please see *Note 11 – Commitments and Contingencies* in Part 1, Item 1 of this Quarterly Report.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

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

Commodity Price Risk

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

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

The following tables present our derivative positions related to crude oil and natural gas sales in effect as of September 30, 2018:

	December 31, 2018	March 31, 2019	June 30, 2019	September 30, 2019	December 31, 2019
NYMEX WTI Crude Swaps:					
Notional volume (Bbl)	1,050,000	—	—	—	—
Weighted average fixed price ($/Bbl)	$ 52.91	$ —	$ —	$ —	$ —
NYMEX WTI Crude Purchased Puts:					
Notional volume (Bbl)	2,250,000	2,850,000	2,850,000	1,800,000	1,800,000
Weighted average purchased put price ($/Bbl)	$ 49.81	$ 49.72	$ 49.72	$ 54.17	$ 54.17
NYMEX WTI Crude Sold Calls:					
Notional volume (Bbl)	2,250,000	2,850,000	2,850,000	1,800,000	1,800,000
Weighted average fixed price ($/Bbl)	$ 58.33	$ 60.77	$ 60.77	$ 71.13	$ 71.13
NYMEX WTI Crude Sold Puts:					
Notional volume (Bbl)	3,300,000	2,850,000	2,850,000	1,500,000	1,500,000
Weighted average purchased put price ($/Bbl)	$ 40.00	$ 40.16	$ 40.16	$ 44.60	$ 44.60
NYMEX HH Natural Gas Swaps:					
Notional volume (MMBtu)	9,900,000	4,200,000	7,200,000	7,200,000	7,200,000
Weighted average fixed price ($/MMBtu)	$ 3.02	$ 3.07	$ 2.71	$ 2.71	$ 2.71
NYMEX HH Natural Gas Purchased Puts:					
Notional volume (MMBtu)	600,000	3,000,000	—	—	—
Weighted average sold call price ($/MMBtu)	$ 3.00	$ 2.99	$ —	$ —	$ —
NYMEX HH Natural Gas Sold Calls:					
Notional volume (MMBtu)	600,000	3,000,000	—	—	—
Weighted average purchased put price ($/MMBtu)	$ 3.15	$ 3.36	$ —	$ —	$ —
NYMEX HH Natural Gas Sold Puts:					
Notional volume (MMBtu)	—	3,000,000	—	—	—
Weighted average sold put price ($/MMBtu)	$ —	$ 2.50	$ —	$ —	$ —
CIG Basis Gas Swaps:					
Notional volume (MMBtu)	11,040,000	7,800,000	7,800,000	7,800,000	7,800,000
Weighted average fixed basis price ($/MMBtu)	$ (0.68)	$ (0.75)	$ (0.75)	$ (0.75)	$ (0.75)

As of September 30, 2018, the fair market value of our oil derivative contracts was a net liability of $140.8 million. Based on our open oil derivative positions at September 30, 2018, a 10% increase in the NYMEX WTI price would increase our net oil derivative liability by approximately $77.5 million, while a 10% decrease in the NYMEX WTI price would decrease our net oil derivative liability by approximately $69.6 million. As of September 30, 2018, the fair market value of our natural gas derivative contracts was a net asset of $1.7 million. Based upon our open commodity derivative positions at September 30, 2018, a 10% increase in the NYMEX Henry Hub price would decrease our net natural gas derivative asset by approximately $7.4 million, while a 10% decrease in the NYMEX Henry Hub price would increase our net natural gas derivate asset by approximately $7.5 million. Please see "—How We Evaluate Our Operations—Derivative Arrangements."

Counterparty and Customer Credit Risk

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

We sell oil, natural gas and NGL to various types of customers, including pipelines and refineries. Credit is extended based on an evaluation of the customer's financial conditions and historical payment record. The future availability of a ready market for oil, natural gas and NGL depends on numerous factors outside of our control, none of which can be predicted with certainty. For the nine months ended September 30, 2018, 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 September 30, 2018, we had commodity derivative contracts with twelve 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. For the three and nine months ended September 30, 2018 and 2017, we did not incur any losses with respect to counterparty contracts. None of our existing derivative instrument contracts contain credit risk related contingent features.

Interest Rate Risk

At September 30, 2018, we had $290.0 million variable-rate debt outstanding. The impact on interest expense of a 1% increase or decrease in the average interest rate would be approximately $2.9 million per year. We may begin entering into interest rate swap arrangements on a portion of our outstanding debt to mitigate the risk of fluctuations in LIBOR if we have variable-rate debt outstanding in the future. Please see "—Liquidity and Capital Resources—Debt Arrangements."

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Securities Exchange Act of 1934 (the "Exchange Act"), we have evaluated, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Quarterly Report on Form 10-Q. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of September 30, 2018.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the three months ended September 30, 2018 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

From time to time, we are party to ongoing legal proceedings in the ordinary course of business. While the outcome of these proceedings cannot be predicted with certainty, we do not believe the results of these proceedings, individually or in the aggregate, will have a material adverse effect on our business, financial condition, results of operations or liquidity.

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 below and under Item 1A "Risk Factors", included in our Annual Report on Form 10-K filed with the SEC on February 27, 2018. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

Colorado ballot Proposition 112, if approved by voters in November 2018, would likely have a material adverse impact on new oil and gas development in Colorado and on our business.

The Colorado Secretary of State has approved a citizen-initiated ballot measure, referred to as Proposition 112, for inclusion on the statewide voter ballot in November 2018. Proposition 112 seeks to amend the Colorado Revised Statutes to increase setback distances by requiring that all new oil and gas development on non-federal lands (i.e. state and private land) be located at least 2,500 feet away from certain occupied structures, including homes, schools and hospitals, as well as certain defined "vulnerable areas," including playgrounds, permanent sports fields, public parks and open spaces, public drinking water sources, reservoirs, lakes, rivers, perennial and intermittent streams, and creeks. In contrast, rules adopted and enforced by the Colorado Oil & Gas Conservation Commission ("COGCC") currently require that wells and production facilities be located at least 500 feet away from homes and 1,000 feet away from certain defined high occupancy building units, including schools, subject to certain exceptions. The term "oil and gas development" is broadly defined under Proposition 112 to include oil and gas exploration, drilling, hydraulic fracturing, flowlines, production and processing activities, including the development and production activities central to our operations. Under Proposition 112, state and local governments would be allowed to designate vulnerable areas beyond those that are defined in the measure, but the proposal provides no additional guidance on procedures or any limitations with respect to such designations. Proposition 112 further provides that the state or a local government may increase the setback to a distance larger than 2,500 feet, again without any defined procedure, limitations, or governing standards. Proposition 112 would take effect upon official certification of election results, is self-executing, and will apply to new oil and gas development (which includes the reentry of an oil or gas well previously plugged or abandoned) that is permitted on or after the date of certification, but is not expected to apply to previously permitted wells, including drilled but uncompleted wells.

The COGCC conducted a study in 2018 and determined that, if Proposition 112 were approved by state voters, an estimated 54% of Colorado's total land surface would be unavailable for new oil and gas development, or 85% of all non-federal lands. Focusing on Weld County, located in the DJ Basin, the 2018 COGCC study determined that approval and adoption of Proposition 112 would preclude new oil and gas development on approximately 78% of the total land surface and 85% of the non-federal land surface in the county. If Colorado voters approve Proposition 112 in November 2018, then we may be limited in our ability to develop our oil and natural gas reserves in Colorado and such limitation may have a significant and material effect on our expected future revenues and cash flows and results of operations.

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

The following table sets forth our share repurchase activity for each period presented:

Period	Total Number of Shares Purchased	Average Price Paid per Share
July 1, 2018 - July 31, 2018 (1)	153,812	$ 13.82
August 1, 2018 - August 31, 2018	—	—
September 1, 2018 - September 30, 2018	—	—
Total	153,812	$ 13.82

(1) These shares were withheld to satisfy tax withholding payments related to incentive restricted stock unit awards that vested during the period.

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.

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	Consent and Amendment No. 5 to Amended and Restated Credit Agreement, dated as of October 2, 2018, by and among Extraction Oil & Gas, Inc., as borrower, certain of its subsidiaries, as guarantors, the lenders party thereto, and Wells Fargo Bank, National Association, as administrative agent and issuing lender (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 9, 2018).
*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.

SIGNATURES

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

Date: November 6, 2018.

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)

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 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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) 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. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. 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

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

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

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

Date: November 6, 2018

/S/ MARK A. ERICKSON

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

Exhibit 31.2

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

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

1. I have reviewed this quarterly report 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 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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) 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. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. 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

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

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

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

Date: November 6, 2018

/S/ RUSSELL T. KELLEY, JR.

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

Exhibit 32.1

CERTIFICATION OF
CHIEF EXECUTIVE 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 September 30, 2018 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 and Chairman of the Company, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge:

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

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

Date: November 6, 2018

/S/ MARK A. ERICKSON

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

Exhibit 32.2

CERTIFICATION OF
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 September 30, 2018 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 and Chairman of the Company, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge:

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

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

Date: November 6, 2018

/S/ RUSSELL T. KELLEY, JR.

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