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, 2019

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)	

(720) 557-8300

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of exchange on which registered
Common Stock, par value $0.01	**XOG**	**NASDAQ Global Select Market**

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 5, 2019 was 138,628,707.

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.

"Dekatherms" means a unit of energy used primarily to measure natural gas equal to 1,000,000 Btus (MMBtu).

"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, 2019	December 31, 2018
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 57,728	$ 234,986
Accounts receivable		
Trade	55,095	41,695
Oil, natural gas and NGL sales	69,750	91,225
Inventory and prepaid expenses	19,489	26,816
Commodity derivative asset	66,480	48,907
Assets held for sale	—	21,008
Total Current Assets	268,542	464,637
Property and Equipment (successful efforts method), at cost:		
Proved oil and gas properties	4,494,226	3,916,622
Unproved oil and gas properties	572,400	609,284
Wells in progress	104,429	144,323
Less: accumulated depletion, depreciation and amortization	(1,498,608)	(1,152,590)
Net oil and gas properties	3,672,447	3,517,639
Gathering systems and facilities	307,038	114,469
Other property and equipment, net of accumulated depreciation	73,265	39,849
Net Property and Equipment	4,052,750	3,671,957
Non-Current Assets:		
Commodity derivative asset	41,520	8,432
Other non-current assets	66,346	21,001
Total Non-Current Assets	107,866	29,433
Total Assets	$ 4,429,158	$ 4,166,027
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 216,193	$ 186,218
Revenue payable	96,140	117,344
Production taxes payable	114,969	57,516
Commodity derivative liability	108	196
Accrued interest payable	17,272	22,249
Asset retirement obligations	26,426	15,729
Liabilities related to assets held for sale	—	3,146
Total Current Liabilities	471,108	402,398
Non-Current Liabilities:		
Credit facility	550,000	285,000
Senior Notes, net of unamortized debt issuance costs	1,085,217	1,132,659
Production taxes payable	70,560	115,607
Commodity derivative liability	83	—
Other non-current liabilities	23,412	8,072
Asset retirement obligations	67,500	54,062
Deferred tax liability	115,876	109,176
Total Non-Current Liabilities	1,912,648	1,704,576
Total Liabilities	2,383,756	2,106,974
Commitments and Contingencies—Note 11		
Series A Convertible Preferred Stock, $0.01 par value; 50,000,000 shares authorized; 185,280 issued and outstanding	169,282	164,367
Stockholders' Equity:		
Common stock, $0.01 par value; 900,000,000 shares authorized; 138,073,124 and 171,666,485 issued and outstanding	1,336	1,678
Treasury stock, at cost, 38,859,078 and 4,543,262 shares	(170,138)	(32,737)
Additional paid-in capital	2,164,921	2,153,661
Accumulated deficit	(378,220)	(375,788)
Total Extraction Oil & Gas, Inc. Stockholders' Equity	1,617,899	1,746,814
Noncontrolling interest	258,221	147,872
Total Stockholders' Equity	1,876,120	1,894,686
Total Liabilities and Stockholders' Equity	$ 4,429,158	$ 4,166,027

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,	
	2019	2018	2019	2018
Revenues:				
Oil sales	$ 171,074	$ 225,467	$ 521,623	$ 619,211
Natural gas sales	16,801	23,103	74,385	66,991
NGL sales	9,099	33,590	44,940	86,369
Total Revenues	196,974	282,160	640,948	772,571
Operating Expenses:				
Lease operating expenses	22,979	20,283	68,445	61,760
Transportation and gathering	6,922	11,786	29,142	29,284
Production taxes	9,711	21,605	46,419	66,317
Exploration expenses	13,245	11,038	32,725	21,326
Depletion, depreciation, amortization and accretion	114,996	107,315	352,134	310,296
Impairment of long lived assets	—	16,166	11,233	16,294
Gain on sale of property and equipment and assets of unconsolidated subsidiary	(1,011)	(83,559)	(1,329)	(143,461)
General and administrative expenses	27,445	35,365	85,835	100,565
Total Operating Expenses	194,287	139,999	624,604	462,381
Operating Income	2,687	142,161	16,344	310,190
Other Income (Expense):				
Commodity derivatives gain (loss)	87,956	(35,913)	39,383	(175,752)
Interest expense	(23,224)	(20,725)	(54,791)	(103,229)
Other income	1,337	1,827	3,332	3,094
Total Other Income (Expense)	66,069	(54,811)	(12,076)	(275,887)
Income Before Income Taxes	68,756	87,350	4,268	34,303
Income tax expense	(20,600)	(22,200)	(6,700)	(12,300)
Net Income (Loss)	$ 48,156	$ 65,150	$ (2,432)	$ 22,003
Net income attributable to noncontrolling interest	5,776	3,305	13,849	3,305
Net Income (Loss) Attributable to Extraction Oil & Gas, Inc.	42,380	61,845	(16,281)	18,698
Adjustments to reflect Series A Preferred Stock dividends and accretion of discount	(4,403)	(4,236)	(13,079)	(12,593)
Net Income (Loss) Attributable to Common Shareholders	37,977	57,609	(29,360)	6,105
Income (Loss) Per Common Share (Note 10)				
Basic and diluted	$ 0.28	$ 0.33	$ (0.19)	$ 0.03
Weighted Average Common Shares Outstanding				
Basic and diluted	137,789	175,814	155,847	175,269

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

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

	Common Stock		Treasury Stock		Additional Paid in Capital	Accumulated Deficit	Extraction Oil & Gas, Inc. Stockholders' Equity	Noncontrolling interest	Total Stockholders' Equity
	Shares	Amount	Shares	Amount				Amount	
Balance at January 1, 2019	176,210	$ 1,678	4,543	$ (32,737)	$ 2,153,661	$ (375,788)	$ 1,746,814	$ 147,872	$ 1,894,686
Preferred Units commitment fees & dividends paid-in-kind	—	—	—	—	(3,975)	—	(3,975)	3,975	—
Stock-based compensation	—	—	—	—	13,008	—	13,008	—	13,008
Series A Preferred Stock dividends	—	—	—	—	(2,721)	—	(2,721)	—	(2,721)
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	(1,596)	—	(1,596)	—	(1,596)
Repurchase of common stock	—	(77)	7,824	(32,135)	—	—	(32,212)	—	(32,212)
Restricted stock issued, including payment of tax withholdings using withheld shares	270	—	—	—	(454)	—	(454)	—	(454)
Net loss	—	—	—	—	—	(94,032)	(94,032)	—	(94,032)
Balance at March 31, 2019	176,480	$ 1,601	12,367	$ (64,872)	$ 2,157,923	$ (469,820)	$ 1,624,832	$ 151,837	$ 1,776,669
Preferred Units commitment fees & dividends paid-in-kind	—	—	—	—	(4,098)	—	(4,098)	4,098	—
Stock-based compensation	—	—	—	—	14,957	—	14,957	—	14,957
Series A Preferred Stock dividends	—	—	—	—	(2,722)	—	(2,722)	—	(2,722)
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	(1,637)	—	(1,637)	—	(1,637)
Repurchase of common stock	—	(217)	21,685	(84,067)	—	—	(84,284)	—	(84,284)
Restricted stock issued, including payment of tax withholdings using withheld shares	108	—	—	—	(128)	—	(128)	—	(128)
Net income	—	—	—	—	—	43,444	43,444	—	43,444
Balance at June 30, 2019	176,588	$ 1,384	34,052	$ (148,939)	$ 2,164,295	$ (426,376)	$ 1,590,364	$ 155,945	$ 1,746,309
Preferred Units issued	—	—	—	—	—	—	—	99,000	99,000
Preferred Units issuance costs	—	—	—	—	—	—	—	(2,500)	(2,500)
Preferred Units commitment fees & dividends paid-in-kind	—	—	—	—	(5,776)	—	(5,776)	5,776	—
Stock-based compensation	—	—	—	—	11,387	—	11,387	—	11,387
Series A Preferred Stock dividends	—	—	—	—	(2,721)	—	(2,721)	—	(2,721)
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	(1,682)	—	(1,682)	—	(1,682)
Repurchase of common stock	—	(48)	4,807	(21,199)	—	—	(21,247)	—	(21,247)
Restricted stock issued, including payment of tax withholdings using withheld shares	344	—	—	—	(582)	—	(582)	—	(582)
Net income	—	—	—	—	—	48,156	48,156	—	48,156
Balance at September 30, 2019	176,932	$ 1,336	38,859	$ (170,138)	$ 2,164,921	$ (378,220)	$ 1,617,899	$ 258,221	$ 1,876,120

	Common Stock		Treasury Stock		Additional Paid in Capital	Accumulated Deficit	Extraction Oil & Gas, Inc. Stockholders' Equity	Noncontrolling interest	Total Stockholders' Equity
	Shares	Amount	Shares	Amount				Amount	
Balance at January 1, 2018	172,060	$ 1,718	165	$ (2,105)	$ 2,114,795	$ (497,643)	$ 1,616,765	$ —	$ 1,616,765
Stock-based compensation	2,794	—	—	—	15,721	—	15,721	—	15,721
Series A Preferred Stock dividends	—	—	—	—	(2,721)	—	(2,721)	—	(2,721)
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	(1,438)	—	(1,438)	—	(1,438)
Repurchase of common stock	—	—	166	(2,309)	—	—	(2,309)	—	(2,309)
Restricted stock issued, including payment of tax withholdings using withheld shares	852	—	—	—	(2,305)	—	(2,305)	—	(2,305)
Net loss	—	—	—	—	—	(51,995)	(51,995)	—	(51,995)
Balance at March 31, 2018	175,706	$ 1,718	331	$ (4,414)	$ 2,124,052	$ (549,638)	$ 1,571,718	$ —	$ 1,571,718
Stock-based compensation	—	—	—	—	17,743	—	17,743	—	17,743
Series A Preferred Stock dividends	—	—	—	—	(2,722)	—	(2,722)	—	(2,722)
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	(1,477)	—	(1,477)	—	(1,477)
Repurchase of common stock	—	—	—	—	—	—	—	—	—
Restricted stock issued, including payment of tax withholdings using withheld shares	92	—	—	—	(226)	—	(226)	—	(226)
Net income	—	—	—	—	—	8,848	8,848	—	8,848
Balance at June 30, 2018	175,798	$ 1,718	331	$ (4,414)	$ 2,137,370	$ (540,790)	$ 1,593,884	$ —	$ 1,593,884
Preferred Units issued	—	—	—	—	—	—	—	148,500	148,500
Preferred Units issuance costs	—	—	—	—	—	—	—	(7,933)	(7,933)
Preferred Units commitment fees & dividends paid-in-kind	—	—	—	—	(3,305)	—	(3,305)	3,305	—
Stock-based compensation	—	—	—	—	17,420	—	17,420	—	17,420
Series A Preferred Stock dividends	—	—	—	—	(2,721)	—	(2,721)	—	(2,721)
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	(1,515)	—	(1,515)	—	(1,515)
Repurchase of common stock	—	—	154	(2,125)	—	—	(2,125)	—	(2,125)
Restricted stock issued, including payment of tax withholdings using withheld shares	63	—	—	—	(331)	—	(331)	—	(331)
Net income	—	—	—	—	—	65,150	65,150	—	65,150
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,	
	2019	**2018**
Cash flows from operating activities:		
Net income (loss)	$ (2,432)	$ 22,003
Reconciliation of net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, amortization and accretion	352,134	310,296
Abandonment and impairment of unproved properties	26,166	15,463
Impairment of long lived assets	11,233	16,294
Gain on sale of property and equipment	(319)	(59,849)
Gain on sale of assets of unconsolidated subsidiary	(1,010)	(83,612)
Gain on repurchase of 2026 Senior Notes	(10,486)	—
Amortization of debt issuance costs	3,799	12,303
Non-cash lease expense	7,739	—
Deferred rent	—	442
Commodity derivatives (gain) loss	(39,383)	175,752
Settlements on commodity derivatives	(18,527)	(93,482)
Premiums paid on commodity derivatives	(2,852)	(17,271)
Earnings in unconsolidated subsidiaries	(1,217)	(1,886)
Distributions from unconsolidated subsidiaries	2,630	1,684
Make-whole premium paid on 2021 Senior Notes	—	35,600
Deferred income tax expense	6,700	12,300
Stock-based compensation	39,306	50,883
Changes in current assets and liabilities:		
Accounts receivable—trade	(1,395)	4,573
Accounts receivable—oil, natural gas and NGL sales	16,293	(13,865)
Inventory and prepaid expenses	(3,479)	(637)
Accounts payable and accrued liabilities	231	(14,780)
Revenue payable	(21,723)	60,946
Production taxes payable	12,211	49,657
Accrued interest payable	(4,977)	(5,015)
Asset retirement expenditures	(14,081)	(9,437)
Net cash provided by operating activities	356,561	468,362
Cash flows from investing activities:		
Oil and gas property additions	(526,187)	(774,787)
Sale of property and equipment	41,982	72,345
Gathering systems and facilities additions	(169,180)	(41,359)
Other property and equipment additions	(32,575)	(11,944)
Investment in unconsolidated subsidiaries	(22,487)	(6,000)
Distributions from unconsolidated subsidiary, return of capital	569	—
Sale of assets of unconsolidated subsidiary	1,010	83,612
Net cash used in investing activities	(706,868)	(678,133)
Cash flows from financing activities:		
Borrowings under credit facility	375,000	590,000
Repayments under credit facility	(110,000)	(390,000)
Proceeds from the issuance of 2026 Senior Notes	—	739,664
Repayments of 2021 Senior Notes	—	(550,000)
Make-whole premium paid on 2021 Senior Notes	—	(35,600)
Repurchase of 2026 Senior Notes	(39,325)	—
Repurchase of commons stock	(137,743)	(4,434)
Payment of employee payroll withholding taxes	(1,164)	(2,862)
Dividends on Series A Preferred Stock	(8,164)	(8,164)
Debt and equity issuance costs	(2,055)	(3,103)
Proceeds from issuance of Preferred Units	99,000	148,500
Preferred Unit issuance costs	(2,500)	(6,933)
Net cash provided by financing activities	173,049	477,068
(Decrease) increase in cash and cash equivalents	(177,258)	267,297
Cash, cash equivalents and restricted cash at beginning of period	234,986	6,768
Cash, cash equivalents and restricted cash at end of the period	$ 57,728	$ 274,065
Supplemental cash flow information:		
Property and equipment included in accounts payable and accrued liabilities	$ 158,178	$ 148,156
Cash paid for interest	$ 71,878	$ 66,673
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	$ 4,915	$ 4,429
Preferred Units paid-in-kind commitment fees and dividends	$ 13,849	$ 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".

Elevation Midstream, LLC (“Elevation”), a Delaware limited liability company and an unrestricted subsidiary of the Company, is focused on the construction of gathering systems and facilities operations to serve the development of acreage in the Company’s Hawkeye and Southwest Wattenberg areas. Midstream assets of Elevation are represented as the gathering systems and facilities line item within the condensed consolidated balance sheets. As of September 30, 2019, these gathering systems and facilities operations were not in service, therefore, there were no associated revenues for the three and nine months then ended. On October 3, 2019, Elevation commenced moving crude oil, natural gas and water through its Badger central gathering facility, which enables Extraction to efficiently transport its crude oil and natural gas production along with water used during the completion process. The use of this gathering facility allows for the elimination of oil or water storage on the well pad site and reduces truck traffic, which minimizes the impact to the surrounding environment and communities.

On July 10, 2019, Elevation closed on the issuance of an additional 100,000 Preferred Units of Elevation (the "Elevation Preferred Units") under an existing securities purchase agreement with a third party, pursuant to which Elevation had agreed to sell an additional 100,000 Elevation Preferred Units at a price of $990 per Elevation Preferred Unit with an aggregate liquidation preference of $100.0 million, and resulting in net proceeds of approximately $96.5 million, after deducting discounts and related offering expenses. These Elevation Preferred Units are non-recourse to Extraction.

On November 19, 2018, the Company announced that the Board of Directors had authorized a program to repurchase up to $100.0 million of the Company's common stock ("Stock Repurchase Program"). On April 1, 2019, the Company announced the Board of Directors had authorized an extension and increase to the ongoing Stock Repurchase Program bringing the total amount authorized to $163.2 million ("Extended Stock Repurchase Program"). Prior to commencing the Extended Stock Repurchase Program, the Company had purchased approximately 13.0 million shares of its common stock for $63.2 million under the Stock Repurchase Program. The Company was authorized to repurchase an incremental $100.0 million in common stock, which repurchases were completed in the third quarter of 2019, bringing the total amount of common stock repurchased to $163.2 million. During the three and nine months ended September 30, 2019, the Company repurchased approximately 4.8 million and 34.1 million shares of its common stock for $21.2 million and $136.9 million, respectively.

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 unaudited 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.

Leases

The Company accounts for leases in accordance with Accounting Standards Codification ("ASC") 842, *Leases*, which it adopted on January 1, 2019, applying the modified retrospective transition approach as of the effective date of adoption (see *"Recent Accounting Pronouncements"* for impacts of adoption).

The Company enters into operating leases for certain drilling equipment, completions equipment, equipment ancillary to drilling and completions, office facilities, compressors and office equipment. Under ASC 842, a contract is or contains a lease when (i) the contract contains an explicitly or implicitly identified asset and (ii) the customer obtains substantially all of the economic benefits from the use of that underlying asset and directs how and for what purpose the asset is used during the term of the contract in exchange for consideration. The Company assesses whether an arrangement is or contains a lease at inception of the contract. All leases (operating leases), other than those that qualify for the short-term recognition exemption, are recognized as of the lease commencement date on the balance sheet as a liability for its obligation related to the lease and a corresponding asset representing its right to use the underlying asset over the period of use.

The Company's leases have remaining terms up to nine years. Certain of our lease agreements contain options to extend or early terminate the agreement. The lease term used to calculate the lease asset and liability at commencement includes options to extend or terminate the lease when it is reasonably certain that we will exercise that option. When determining whether it is reasonably certain that the Company will exercise an option at commencement, it considers various economic factors, including capital expenditure strategies, the nature, length, and underlying terms of the agreement, as well as the uncertainty of the condition of leased equipment at the end of the lease term. Based on these determinations, the Company generally determines that the exercise of renewal options would not be reasonably certain in determining the expected lease term for leases, other than certain operating compressor leases.

The discount rate used to calculate the present value of the future minimum lease payments is the rate implicit in the lease, when readily determinable. As the Company's leases generally do not provide an implicit rate, the Company uses its incremental borrowing rate based on its revolving credit facility, which includes consideration of the nature, term, and geographic location of the leased asset.

Certain of the Company's leases include variable lease payments, including payments that depend on an index or rate, as well as variable payments for items such as property taxes, insurance, maintenance, and other operating expenses associated with leased assets. Payments that vary based on an index or rate are included in the measurement of the Company's lease assets and liabilities at the rate as of the commencement date. All other variable lease payments are excluded from the measurement of the Company's lease assets and liabilities and are recognized in the period in which the obligation for those payments is incurred. The Company's lease agreements do not contain any material residual value guarantees or material restrictive covenants.

The Company has elected, for all classes of underlying assets, to not apply the balance sheet recognition requirements of ASC 842 to leases with a term of one year or less, and instead, recognize the lease payments in the condensed consolidated statements of operations on a straight-line basis over the lease term. The Company has also made the election, for its certain drilling equipment, completions equipment, equipment ancillary to drilling and completions, compressors and office equipment classes of underlying assets, to account for lease and non-lease components in a contract as a single lease component.

For the three and nine months ended September 30, 2019, lease costs, which represent the straight-line lease expense of right-of-use ("ROU") assets and short-term leases, were as follows (in thousands):

	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2019
Lease Costs included in the Condensed Consolidated Balance Sheets		
Proved oil and gas properties, including drilling, completions and ancillary equipment, and gathering systems and facilities (1)	$ 92,023	$ 230,940
Lease Costs included in the Condensed Consolidated Statements of Operations		
Operating lease costs (2)	$ 9,210	$ 22,627
General and administrative expenses (3)	$ 1,054	$ 2,811
Total operating lease costs	$ 10,264	$ 25,438
Total lease costs	$ 102,287	$ 256,378

(1) Represents short-term lease capital expenditures related to drilling rigs, completions equipment and other equipment ancillary to the drilling and completion of wells.
(2) Includes $2.3 million and $6.5 million of lease costs and $0.2 million and $0.4 million of variable costs associated with operating leases for the three and nine months ended September 30, 2019, respectively.
(3) Includes $0.3 million and $1.0 million of lease costs and $0.4 million and $1.0 million of variable costs associated with operating leases, as well as $0.1 million and $0.2 million of sublease income for the three and nine months ended September 30, 2019, respectively.

Supplemental cash flow information related to operating leases for the nine months ended September 30, 2019, was as follows (in thousands):

	Nine Months Ended September 30, 2019
Cash paid for amounts included in the measurements of lease liabilities	
Operating cash flows from operating leases	$ (9,014)
Right-of-use assets obtained in exchange for lease obligations	
Operating leases	$ (2,997)

Supplemental balance sheet information related to operating and finance leases as of September 30, 2019, were as follows (in thousands, except lease term and discount rate):

	Classification	As of September 30, 2019
Operating Leases		
Operating lease right-of-use assets	Other non-current assets	$ 20,470
Operating lease obligation - short-term	Accounts payable and accrued liabilities	9,236
Operating lease obligation - long-term	Other non-current liabilities	16,827
Total operating lease liabilities		$ 26,063
Weighted Average Remaining Lease Term in Years		
Operating leases		5.8
Weighted Average Discount Rate		
Operating leases		4.7 %

As of September 30, 2019, the Company was subject to commitments on one drilling rig contracted through November 2019. These costs are capitalized within proved oil and gas properties on the condensed consolidated balance sheets and are included as short-term lease costs. Beginning in November 2019, the Company will be subject to commitments on one drilling rig contracted through February 2021. As of September 30, 2019, the Company had an insignificant amount of additional operating leases that have not yet commenced, of which none included involvement with the construction or design of the underlying asset.

Recent Accounting Pronouncements

In February 2016, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2016-02—Leases (Topic 842), 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. The FASB subsequently issued ASU No. 2017-13, ASU No. 2018-01, ASU No. 2018-10, ASU No. 2018-11 and ASU No. 2019-01, which provided additional implementation guidance. The Company adopted the accounting standard using a modified retrospective transition approach, which applies the provisions of the new guidance at the effective date without adjusting the comparative periods presented. The Company has elected the package of practical expedients permitted under the transition guidance with the new standard, which among other things, requires no reassessment of whether existing contracts are or contain leases as well as no reassessment of lease classification for existing leases upon adoption. The Company has also elected the optional practical expedient permitted under the transition guidance within the new standard related to land easements that allows it to carry forward its current accounting treatment for land easements on existing agreements upon adoption. The Company made an accounting policy election to keep leases with an initial term of twelve months or less off of the condensed consolidated balance sheet.

The adoption of this guidance resulted in the recognition of right-of-use ("ROU") assets of approximately $26.3 million, and current and non-current lease liabilities for operating leases of approximately $10.1 million and $21.1 million, respectively, as of January 1, 2019, including immaterial reclassifications of prepaid rent, deferred rent and lease incentive liability balances. The adoption of this guidance did not have a material impact to the Company's cash flows from operating, investing, or financing activities.

In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments—Credit Losses. In May 2019, ASU No. 2016-13 was subsequently amended by ASU No. 2019-04, Codification Improvements to Topic 326, Financial Instruments—Credit Losses and ASU No. 2019-05, Financial Instruments—Credit Losses (Topic 326): Targeted Transition Relief. ASU No. 2016-13, as amended, affects trade receivables, financial assets and certain other instruments that are not measured at fair value through net income. This ASU will replace the currently required incurred loss approach with an expected loss model for instruments measured at amortized cost and is effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. ASU No. 2016-13 will be applied using a modified retrospective approach through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. The Company does not believe the adoption of this ASU will have a material impact on the Company’s consolidated financial statements as the Company does not have a history of material credit losses.

In August 2018, the FASB issued Accounting Standards Update 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.

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 unaudited condensed 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 2019 Divestiture

On August 22, 2019, the Company completed the sale of certain non-operated producing properties for aggregate sales proceeds of approximately $22.0 million, subject to customary purchase price adjustments. No gain or loss was recognized for the August 2019 Divestiture. The Company continues to explore divestitures, as part of our ongoing initiative to divest of non-strategic assets.

March 2019 Divestiture

On March 27, 2019, the Company completed the sale of its interests in approximately 5,000 net acres of leasehold and producing properties for aggregate sales proceeds of approximately $22.4 million. The effective date for the March 2019 Divestiture was July 1, 2018 with purchase price adjustments calculated as of the closing date of $5.9 million, resulting in net proceeds of $16.5 million. No gain or loss was recognized for the March 2019 Divestiture.

December 2018 Divestitures

In December 2018, the Company completed various sales of its interests in approximately 31,200 net acres of leasehold and primarily non-producing properties, for aggregate sales proceeds of approximately $8.5 million, subject to customary purchase price adjustments, and recognized a loss of $6.1 million for the year ended December 31, 2018.

August 2018 Divestiture

On August 3, 2018, Elevation received proceeds of $83.6 million and recognized a gain of $83.6 million for the year ended December 31, 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 $59.3 million for the year ended December 31, 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. 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. 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.

Note 4—Long-Term Debt

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

	September 30, 2019	December 31, 2018
Credit facility due August 16, 2022 (or an earlier time as set forth in the credit facility)	$ 550,000	$ 285,000
2024 Senior Notes due May 15, 2024	400,000	400,000
2026 Senior Notes due February 1, 2026	700,189	750,000
Unamortized debt issuance costs on Senior Notes	(14,972)	(17,341)
Total long-term debt	1,635,217	1,417,659
Less: current portion of long-term debt	—	—
Total long-term debt, net of current portion	$ 1,635,217	$ 1,417,659

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 2019, the Company amended its revolving credit facility to permit prepayments and redemptions of its unsecured bonds, subject to certain term, conditions and financial thresholds.

In June 2019, the Company amended its revolving credit facility to (i) increase the elected commitments from $650.0 million to $900.0 million, (ii) increase the amount for permitted letters of credit from $50.0 million to $100.0 million and increase in the letter of credit for the Company's oil marketer from $35.0 million to $40.0 million, (iii) decrease the borrowing base from $1.2 billion to $1.1 billion and (iv) increase the limitation on permitted investments from $15.0 million to $20.0 million.

In August 2019, the Company amended its revolving credit facility to increase the elected commitments from $900.0 million to $1.0 billion.

As of September 30, 2019, the credit facility was subject to a borrowing base of $1.1 billion, subject to current elected commitments of $1.0 billion. As of September 30, 2019 and December 31, 2018, the Company had outstanding borrowings of $550.0 million and $285.0 million, respectively, and had standby letters of credit of $49.4 million and $35.7 million, respectively, which reduces the availability of the undrawn borrowing base. At September 30, 2019, the undrawn balance under the credit facility was $450.0 million before letters of credit. This undrawn balance may be constrained by the Company's quantitative covenants under the credit facility, including the current ratio and ratio of consolidated debt less cash balances to its consolidated EBITDAX, at the next required quarterly compliance date. As of October 31, 2019, the Company has $550.0 million in borrowings outstanding under the credit facility.

On November 4, 2019, the Company amended its revolving credit facility to decrease the borrowing base from $1.1 billion to $950.0 million, associated with the scheduled borrowing base redetermination. The current elected commitments were also decreased to $950.0 million.

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, 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 on the last day of each quarter with a current ratio of its restricted subsidiaries' current assets (includes availability under the revolving credit facility and unrestricted cash and excludes derivative assets) to its restricted subsidiaries' 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 its restricted subsidiaries' debt less cash balances to its restricted subsidiaries EBITDAX (EBITDAX is defined as net income adjusted for interest expense, income tax expense/benefit, DD&A, exploration expenses as well as certain non-recurring cash and non-cash charges and income (such as stock-based compensation expense, unrealized gains/losses on commodity derivatives and impairment of long-lived assets), subject to pro forma adjustments for non-ordinary course acquisitions and divestitures) 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, 2019 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, 2019, $49.9 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, 2019, the Company had debt issuance costs, net of accumulated amortization, of $3.9 million related to its credit facility which has been reflected on the Company’s condensed consolidated balance sheet within the line item other non-current assets. As of September 30, 2019, the Company had debt issuance costs, net of accumulated amortization, of $15.0 million related to its 2024 and 2026 Senior Notes (collectively, the "Senior Notes") which has been reflected on the Company's balance sheet within the line item Senior Notes, net of unamortized debt issuance costs. Debt issuance costs include origination, legal, engineering and other fees incurred in connection with the Company’s credit facility and Senior Notes. For the three and nine months ended September 30, 2019, the Company recorded amortization expense related to debt issuance costs of $1.0 million and $3.8 million, respectively, as compared to $0.9 million and $12.3 million for the three and nine months ended September 30, 2018, respectively. Debt issuance costs for the nine months ended September 30, 2018 included $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 and nine months ended September 30, 2019 and the three and nine months ended September 30, 2018.

Interest Incurred on Long-Term Debt

For the three and nine months ended September 30, 2019, the Company incurred interest expense on long-term debt of $23.8 million and $66.9 million, respectively, as compared to $21.5 million and $61.6 million for the three and nine months ended September 30, 2018, respectively. For the three and nine months ended September 30, 2019, the Company capitalized interest expense on long term debt of $1.6 million and $5.4 million, respectively, as compared to $1.7 million and $6.3 million for the three and nine months ended September 30, 2018, 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 was 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 and nine months ended September 30, 2019 and the three months ended September 30, 2018.

Senior Note Repurchase Program

On January 4, 2019, the Board of Directors authorized a program to repurchase up to $100.0 million of the Company’s Senior Notes. The Company’s Senior Notes Repurchase Program is subject to restrictions under our Credit Facility and does not obligate it to acquire any specific nominal amount of Senior Notes. For the three months ended September 30, 2019, the Company did not repurchase 2026 Senior Notes. For the nine months ended September 30, 2019, the Company repurchased a nominal value of $49.8 million for $39.3 million in connection with the Senior Notes Repurchase Program. Interest expense for the nine months ended September 30, 2019 included a $10.5 million gain on debt repurchase related to the Company's Senior Note Repurchase Program. The Senior Note Repurchase Program had no impact to interest expense for three and nine 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 nine 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 risks 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, 2019 are summarized below:

	2019	2020	2021	2022	2023
NYMEX WTI Crude Swaps:					
Notional volume (Bbl)	3,950,000	3,200,001	3,000,000	1,020,000	900,000
Weighted average fixed price ($/Bbl)	$ 57.86	$ 59.81	$ 57.80	$ 54.84	$ 54.87
NYMEX WTI Crude Purchased Puts:					
Notional volume (Bbl)	200,000	9,725,001	1,800,000	—	—
Weighted average purchased put price ($/Bbl)	$ 60.00	$ 54.99	$ 55.02	$ —	$ —
NYMEX WTI Crude Sold Calls:					
Notional volume (Bbl)	200,000	9,725,001	1,800,000	—	—
Weighted average sold call price ($/Bbl)	$ 64.00	$ 62.04	$ 63.70	$ —	$ —
NYMEX WTI Crude Sold Puts:					
Notional volume (Bbl)	1,000,000	12,250,002	4,200,000	600,000	600,000
Weighted average sold put price ($/Bbl)	$ 44.60	$ 42.91	$ 43.50	$ 43.00	$ 43.00
NYMEX HH Natural Gas Swaps:					
Notional volume (MMBtu)	9,000,000	35,400,000	—	—	—
Weighted average fixed price ($/MMBtu)	$ 2.75	$ 2.75	$ —	$ —	$ —
NYMEX HH Natural Gas Purchased Puts:					
Notional volume (MMBtu)	—	600,000	—	—	—
Weighted average purchased put price ($/MMBtu)	$ —	$ 2.90	$ —	$ —	$ —
NYMEX HH Natural Gas Sold Calls:					
Notional volume (MMBtu)	—	600,000	—	—	—
Weighted average sold call price ($/MMBtu)	$ —	$ 3.48	$ —	$ —	$ —
CIG Basis Gas Swaps:					
Notional volume (MMBtu)	11,100,000	43,200,000	—	—	—
Weighted average fixed basis price ($/MMBtu)	$ (0.72)	$ (0.61)	$ —	$ —	$ —

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, 2019				
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 [4]	$ 114,221	$ (47,741)	$ 66,480	$ (83)	$ 107,917
Non-current assets	$ 77,188	$ (35,668)	$ 41,520	$ —	$ —
Current liabilities [4]	$ (47,849)	$ 47,741	$ (108)	$ 83	$ (108)
Non-current liabilities	$ (35,751)	$ 35,668	$ (83)	$ —	$ —

	As of December 31, 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 [5]	$ 115,852	$ (66,945)	$ 48,907	$ (192)	$ 57,147
Non-current assets	$ 17,217	$ (8,785)	$ 8,432	$ —	$ —
Current liabilities [5]	$ (67,141)	$ 66,945	$ (196)	$ 192	$ (4)
Non-current liabilities	$ (8,785)	$ 8,785	$ —	$ —	$ —

(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.
(4) Gross current liabilities include a deferred premium liability of $1.7 million related to the Company's deferred premiums. Gross current assets include a deferred premium asset of $0.4 million related to the Company's deferred premiums.
(5) Gross current liabilities include a deferred premium liability of $7.7 million related to the Company's deferred put premiums. Gross current assets include a deferred premium asset of $0.8 million related to the Company's deferred put premiums.

The table below sets forth the commodity derivatives gain (loss) for the three and nine months ended September 30, 2019 and 2018 (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,	
	2019	**2018**	**2019**	**2018**
Commodity derivatives gain (loss)	$ 87,956	$ (35,913)	$ 39,383	$ (175,752)

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, 2019
Balance beginning of period	$	69,791
Liabilities incurred or acquired	$	315
Liabilities settled	$	(15,484)
Revisions in estimated cash flows	$	35,466
Accretion expense	$	3,838
Balance end of period	$	93,926

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, 2019 and December 31, 2018 by level within the fair value hierarchy (in thousands):

	Fair Value Measurement at September 30, 2019							
	Level 1		Level 2		Level 3		Total	
Financial Assets:								
Commodity derivative assets	$	—	$	108,000	$	—	$	108,000
Financial Liabilities:								
Commodity derivative liabilities	$	—	$	191	$	—	$	191

	Fair Value Measurement at December 31, 2018							
	Level 1		Level 2		Level 3		Total	
Financial Assets:								
Commodity derivative assets	$	—	$	57,339	$	—	$	57,339
Financial Liabilities:								
Commodity derivative liabilities	$	—	$	196	$	—	$	196

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 2024 Senior Notes and 2026 Senior Notes were derived from available market data. As such, the Company has classified the 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, 2019		At December 31, 2018	
	Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
Credit Facility	$ 550,000	$ 550,000	$ 285,000	$ 285,000
2024 Senior Notes[(1)]	$ 394,577	$ 262,000	$ 393,866	$ 330,000
2026 Senior Notes[(2)]	$ 690,640	$ 428,865	$ 738,793	$ 558,750

(1) The carrying amount of the 2024 Senior Notes includes unamortized debt issuance costs of $5.4 million and $6.1 million as of September 30, 2019 and December 31, 2018, respectively.

(2) The carrying amount of the 2026 Senior Notes includes unamortized debt issuance costs of $9.5 million and $11.2 million as of September 30, 2019 and December 31, 2018, respectively.

Non-Recurring Fair Value Measurements

The Company applies the provisions of the fair value measurement standard on a non-recurring basis to its non-financial assets and liabilities, including proved property. 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 months ended September 30, 2019, the Company recognized no impairment expense on its proved oil and gas properties. For the nine months ended September 30, 2019, the Company recognized $11.2 million of impairment expense on its proved oil and gas properties.

The fair value did not exceed the Company's carrying amount associated with its proved oil and gas properties in its northern field. 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.

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. 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, 2019 was 156.8%. During the nine months ended September 30, 2019, the Company recognized income tax expense of $6.7 million. The effective rate for the nine months ended September 30, 2019 differs from the statutory U.S. federal income tax rate of 21.0% primarily due to state income taxes and estimated permanent differences. The significant differences during the nine months ended September 30, 2019 as compared with nine months ended months ended September 30, 2018 included income attributable to non-controlling interest and a discrete item regarding the tax deficiency of the stock-based compensation compared to the compensation recognized for financial reporting purposes. The cumulative effect of the estimated permanent differences and discrete items applied to the pre-tax book income for the nine months ended September 30, 2019 resulted in an income tax expense that exceeds book income. 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.

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. In May 2019, the Company's stockholders approved the amendment and restatement of the Company's 2016 Long Term Incentive Plan. The amended and restated 2016 Long Term Incentive Plan provides a total reserve of 32.2 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, performance stock awards, performance stock units, performance cash awards and cash 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 pursuant to the terms of the LTIP. The Company assumed a forfeiture rate of zero as part of the grant date estimate of compensation cost.

The Company recorded $6.6 million and $20.6 million of stock-based compensation costs related to RSUs for the three and nine months ended September 30, 2019, respectively, as compared to $7.1 million and $20.7 million for the three and nine months ended September 30, 2018, respectively. These costs were included in the condensed consolidated statements of operations within the general and administrative expenses line item. As of September 30, 2019, there was $16.5 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 1.5 years.

The following table summarizes the RSU activity from January 1, 2019 through September 30, 2019 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, 2019	3,102,335	$ 16.91
Granted	1,901,418	$ 4.76
Forfeited	(280,029)	$ 12.91
Vested	(1,011,340)	$ 15.33
Non-vested RSUs at September 30, 2019	3,712,384	$ 11.42

Performance Stock Awards

The Company granted performance stock awards ("PSAs") to certain executives under the LTIP in October 2017, March 2018 and April 2019. The number of shares of the Company's common stock that may be issued to settle these various PSAs ranges from zero to two times the number of PSAs awarded. PSA's that settle in cash are presented as liability based awards. 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") or return on invested capital ("ROIC") 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 total 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 and ROIC are 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 $0.7 million and $6.8 million of stock-based compensation costs related to PSAs for the three and nine months ended September 30, 2019, respectively, as compared to $1.6 million and $4.2 million of stock-based compensation related to PSAs for the three and nine months ended September 30, 2018, respectively. These costs were included in the condensed consolidated statements of operations within the general and administrative expenses line item. As of September 30, 2019, there was $9.3 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 1.2 years.

The following table summarizes the PSA activity from January 1, 2019 through September 30, 2019 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, 2019	2,794,083	$ 9.00
Granted	1,646,218	$ 5.44
Forfeited	—	$ —
Vested	—	$ —
Non-vested PSAs at September 30, 2019	4,440,301	$ 7.68

(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 for the 2017 and 2018 grants and ranges from zero to two for the 2019 grants, depending on the level of satisfaction of the vesting condition.

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 $4.0 million and $11.5 million of stock-based compensation costs related to the stock options for the three and nine months ended September 30, 2019, respectively, as compared to $3.8 million and $11.3 million for the three and nine months ended September 30, 2018, respectively. These costs were included in the condensed consolidated statements of operations within the general and administrative expenses line item. As of September 30, 2019, there was $0.7 million of unrecognized compensation cost related to the stock options that is expected to be recognized over a weighted average period of 0.1 years.

The following table summarizes the stock option activity from January 1, 2019 through September 30, 2019 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, 2019	1,748,148	$ 18.50
Granted	—	$ —
Forfeited	—	$ —
Vested	(543,977)	$ 18.72
Non-vested Stock Options at September 30, 2019	1,204,171	$ 18.41

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.

The Company recorded no stock-based compensation costs related to Incentive RSUs for the three months ended September 30, 2019. The Company recorded $0.8 million of stock-based compensation costs related to Incentive RSUs for the nine months ended September 30, 2019. 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. These costs were included in the condensed consolidated statements of operations within the general and administrative expenses line item. As of September 30, 2019, there are no remaining unrecognized compensation costs related to the Incentive RSUs granted to certain employees.

The following table summarizes the Incentive RSU activity from January 1, 2019 through September 30, 2019 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, 2019	476,000	$ 20.45
Granted	—	$ —
Forfeited	—	$ —
Vested	(476,000)	$ 20.45
Non-vested Incentive RSUs at September 30, 2019	—	$ —

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, 2019 and 2018.

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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,	
	2019	2018	2019	2018
Basic and Diluted Income (Loss) Per Share				
Net income (loss)	$ 48,156	$ 65,150	$ (2,432)	$ 22,003
Less: Noncontrolling interest	(5,776)	(3,305)	(13,849)	(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	(1,682)	(1,515)	(4,915)	(4,429)
Adjusted net loss available to common shareholders, basic and diluted	$ 37,977	$ 57,609	$ (29,360)	$ 6,105
Denominator:				
Weighted average common shares outstanding, basic and diluted (1) (2)	137,789	175,814	155,847	175,269
Income (Loss) Per Common Share				
Basic and diluted	$ 0.28	$ 0.33	$ (0.19)	$ 0.03

(1) For the three and nine months ended September 30, 2019, 8,956,812 potentially dilutive shares, including restricted stock awards and stock options outstanding, were not included in the calculation above, as they had an anti-dilutive effect on EPS. 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.

(2) Dilutive restricted stock awards of 347,343 and 537,706 for the three and nine months ended September 30, 2018, respectively, were excluded from the calculation above as the impact of these awards were inconsequential to dilutive weighted average shares outstanding and dilutive EPS. Additionally, for the three and nine months ended September 30, 2018, 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 also excluded, as they would have had an anti-dilutive effect on EPS.

Note 11—Commitments and Contingencies

General

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.

Leases

The Company has entered into operating leases for certain office facilities, compressors and office equipment. On January 1, 2019, the Company adopted ASC Topic 842, Leases, using the modified retrospective approach. Refer to *Note 2—Basis of Presentation, Significant Accounting Policies and Recent Accounting Pronouncements, Leases* for additional information.

Maturities of operating lease liabilities, associated with ROU assets and including imputed interest, as of September 30, 2019, were as follows (in thousands):

	Operating Leases
2019 - remaining	$ 2,956
2020	8,675
2021	3,340
2022	2,211
2023	2,246
Thereafter	10,573
Total lease payments	30,001
Less imputed interest (1)	(3,938)
Present value of lease liabilities (2)	$ 26,063

(1) Calculated using the estimated interest rate for each lease.

(2) Of the total present value of lease liabilities, $9.7 million was recorded in "Accounts payable and accrued liabilities" and$17.2 million was recorded in "Other non-current liabilities" on the condensed consolidated balance sheets.

As of December 31, 2018, minimum future contractual payments for operating leases under the scope of ASC 840 for certain office facilities and drilling rigs are as follows (in thousands):

	Operating Leases
2019 - remaining	$ 12,713
2020	3,371
2021	3,385
2022	3,360
2023	3,411
Thereafter	15,719
Total lease payments	$ 41,959

Drilling Rigs

As of September 30, 2019, the Company was subject to commitments on one drilling rig contracted through November 2019. These costs are capitalized within proved oil and gas properties on the condensed consolidated balance sheets and are included as short-term lease costs in *Note 2—Basis of Presentation, Significant Accounting Policies and Recent Accounting Pronouncements, Leases*. Beginning in November 2019, the Company will be subject to commitments on one drilling rig contracted through February 2021. In the event of early termination of these contracts, the Company would be obligated to pay an aggregate amount of approximately $11.7 million as of September 30, 2019, as required under the terms of the contracts.

Delivery Commitments

As of September 30, 2019, 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. In April 2019, the Company extended the term of this agreement through October 31, 2020, subject to an evergreen provision thereafter and has posted a letter of credit in the amount of $40.0 million. The Company evaluates its contracts for loss contingencies and accrues for such losses, if the loss can be reasonably estimated and deemed probable. During the third quarter of 2019, the Company determined that it likely will not be able to satisfy a portion of the minimum volume commitment in the future and therefore accrued estimated payments up to $6.7 million that will be amortized into oil revenues over the remaining term of the contract.

The Company has two long-term crude oil gathering commitments with an unconsolidated subsidiary, in which the Company has a minority ownership interest, and a long-term gas gathering agreement with a third party midstream provider. The summary of these minimum volume commitments as of September 30, 2019, was as follows:

	Oil (MBbl)	Gas (MMcf)	Total (MBOE)
2019 - Remaining	2,024	5,185	2,888
2020	8,935	33,550	14,527
2021	10,349	46,540	18,106
2022	9,128	49,758	17,421
2023	9,490	41,850	16,465
Thereafter	38,824	74,420	51,227
Total	78,750	251,303	120,634

The aggregate amount of estimated remaining payments under these agreements is $437.8 million.

Also, 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 commenced operations in July 2019. 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. The Company also has a long-term gas gathering agreement with a third party midstream provider that will commence in or around January 2020 and has a term of ten years with an annual minimum volume commitment of 13.0 Bcf in years one through ten. We may be required to pay an annual shortfall fee for any volume deficiencies under this commitment, calculated based on the weighted average sales price during the corresponding annual period. Under its current drilling plans, the Company expects to meet these volume commitments.

In July 2019, the Company entered into three long-term contracts to supply 125,000 dekatherms of residue gas per day for five years to a transportation company. While our production is expected to satisfy these contracts, the aggregate amount of estimated commitment assuming no production is $34.5 million.

Litigation and Legal Items

We are involved in various legal proceedings. We review the status of these proceedings on an ongoing basis and, from time to time, may settle or otherwise resolve these matters on terms and conditions that management believes are in the Company’s best interests. We have provided the necessary estimated accruals in the condensed consolidated balance sheets where deemed appropriate for litigation and legal related items that are ongoing and not yet concluded. Although the results cannot be known with certainty, we currently believe that the ultimate results of such proceedings will not have a material adverse effect on our business, financial position, results of operations or liquidity.

Environmental. Due to the nature of the natural gas and oil industry, we are exposed to environmental risks. We have various policies and procedures to minimize and mitigate the risks from environmental contamination or with respect to environmental compliance issues. Liabilities are recorded when environmental damages resulting from past events are probable and the costs can be reasonably estimated. Except as discussed herein, we are not aware of any material environmental claims existing as of September 30, 2019 which have not been provided for or would otherwise have a material impact on our financial statements; however, there can be no assurance that current regulatory requirements will not change or that unknown potential past non-compliance with environmental laws, compliance matters or other environmental liabilities will not be discovered on our properties. Accrued environmental liabilities are recorded in other accrued expenses on the condensed consolidated balance sheets. The liability ultimately incurred with respect to a matter may exceed the related accrual.

Colorado Bradenhead Testing Matter. In February 2019, we resolved by an administrative order by consent (“AOC”) with the COGCC administrative claims for allegations of noncompliance of State bradenhead testing rules at six pad sites in Weld County, Colorado. The AOC includes an administrative penalty of $0.8 million, of which $0.65 million of the total penalty is to be offset by our commensurate contribution to a public project and our requirement to undertake the required testing and improvements to the Company’s standard operating procedures. We have concluded that the resolution of this action did not have a material adverse effect on our financial position, results of operations or cash flows.

COGCC Notices of Alleged Violations (“NOAVs”). The Company has received NOAVs from the COGCC for alleged compliance violations that the Company has responded to. At this time, the COGCC has not alleged any specific penalty amounts in these matters. We do not believe that any penalties that could result from these NOAVs will have a material effect on our business, financial condition, results of operations or liquidity, but they may exceed $100,000.

Note 12—Related Party Transactions

Office Lease with Affiliate of a Director

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.

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.

Note 13—Segment Information

Beginning in the fourth quarter of 2018, the Company has two operating segments, (i) the exploration, development and production of oil, natural gas and NGL (the "exploration and production segment") and (ii) the construction and support of midstream assets to gather and process crude oil and gas production (the "gathering and facilities segment"). Prior to the fourth quarter of 2018, the Company had a single operating segment. The gathering systems and facilities operating segment was under development as of September 30, 2019. Capital expenditures associated with gathering systems and facilities are being incurred to develop midstream infrastructure to support the Company's development of its oil and gas leasehold along with third-party activity.

The Company's exploration and production segment revenues are derived from third parties. The Company's gathering and facilities segment was in the construction phase and no revenue generating activities had commenced as of September 30, 2019; however, on October 3, 2019, Elevation commenced moving crude oil, natural gas and water through its Badger central gathering facility.

Financial information of the Company's reportable segments was as follows for the three months ended September 30, 2019 and 2018 (in thousands).

	For the Three Months Ended September 30, 2019			
	Exploration and Production	Gathering and Facilities	Elimination of Intersegment Transactions	Consolidated Total
Revenues:				
Revenues from external customers	$ 196,974	$ —	$ —	$ 196,974
Intersegment revenues	—	—	—	—
Total Revenues	$ 196,974	$ —	$ —	$ 196,974
Operating Expenses and Other Income (Expense):				
Depletion, depreciation, amortization and accretion	$ (114,971)	$ (25)	$ —	$ (114,996)
Interest income	114	355	—	469
Interest expense	(23,224)	—	—	(23,224)
Earnings in unconsolidated subsidiaries	—	640	—	640
Subtotal Operating Expenses and Other Income (Expense):	$ (138,081)	$ 970	$ —	$ (137,111)
Segment Assets	$ 4,015,499	$ 395,224	$ 18,435	$ 4,429,158
Capital Expenditures	$ 134,998	$ 65,098	$ —	$ 200,096
Investment in Equity Method Investees	$ —	$ 35,992	$ —	$ 35,992
Segment EBITDAX	$ 158,523	$ (622)	$ —	$ 157,901

	For the Three Months Ended September 30, 2018			
	Exploration and Production	Gathering and Facilities	Elimination of Intersegment Transactions	Consolidated Total
Revenues:				
Revenues from external customers	$ 282,160	$ —	$ —	$ 282,160
Intersegment revenues	—	—	—	—
Total Revenues	$ 282,160	$ —	$ —	$ 282,160
Operating Expenses and Other Income (Expense):				
Depletion, depreciation, amortization and accretion	$ (107,315)	$ —	$ —	$ (107,315)
Interest income	135	635	—	770
Interest expense	(20,725)	—	—	(20,725)
Earnings in unconsolidated subsidiaries	—	843	—	843
Subtotal Operating Expenses and Other Income (Expense):	$ (127,905)	$ 1,478	$ —	$ (126,427)
Segment Assets	$ 3,894,535	$ 264,014	$ (224)	$ 4,158,325
Capital Expenditures	$ 202,811	$ 37,548	$ —	$ 240,359
Investment in Equity Method Investees	$ —	$ 14,510	$ —	$ 14,510
Segment EBITDAX	$ 170,004	$ (601)	$ —	$ 169,403

Financial information of the Company's reportable segments was as follows for the nine months ended September 30, 2019 and 2018 (in thousands).

	For the Nine Months Ended September 30, 2019			
	Exploration and Production	Gathering and Facilities	Elimination of Intersegment Transactions	Consolidated Total
Revenues:				
Revenues from external customers	$ 640,948	$ —	$ —	$ 640,948
Intersegment revenues	—	—	—	—
Total Revenues	$ 640,948	$ —	$ —	$ 640,948
Operating Expenses and Other Income (Expense):				
Depletion, depreciation, amortization and accretion	$ (352,062)	$ (72)	$ —	$ (352,134)
Interest income	372	1,286	—	1,658
Interest expense	(54,791)	—	—	(54,791)
Earnings in unconsolidated subsidiaries	—	1,179	—	1,179
Subtotal Operating Expenses and Other Income (Expense):	$ (406,481)	$ 2,393	$ —	$ (404,088)
Segment Assets	$ 4,015,499	$ 395,224	$ 18,435	$ 4,429,158
Capital Expenditures	$ 516,510	$ 192,568	$ —	$ 709,078
Investment in Equity Method Investees	$ —	$ 35,992	$ —	$ 35,992
Segment EBITDAX	$ 426,571	$ (1,168)	$ —	$ 425,403

	For the Nine Months Ended September 30, 2018			
	Exploration and Production	Gathering and Facilities	Elimination of Intersegment Transactions	Consolidated Total
Revenues:				
Revenues from external customers	$ 772,571	$ —	$ —	$ 772,571
Intersegment revenues	—	—	—	—
Total Revenues	$ 772,571	$ —	$ —	$ 772,571
Operating Expenses and Other Income (Expense):				
Depletion, depreciation, amortization and accretion	$ (310,296)	$ —	$ —	$ (310,296)
Interest income	280	635	—	915
Interest expense	(103,229)	—	—	(103,229)
Earnings in unconsolidated subsidiaries	—	1,567	—	1,567
Subtotal Operating Expenses and Other Income (Expense):	$ (413,245)	$ 2,202	$ —	$ (411,043)
Segment Assets	$ 3,894,535	$ 264,014	$ (224)	$ 4,158,325
Capital Expenditures	$ 730,878	$ 57,224	$ —	$ 788,102
Investment in Equity Method Investees	$ —	$ 14,510	$ —	$ 14,510
Segment EBITDAX	$ 463,415	$ 102	$ —	$ 463,517

The following table presents a reconciliation of Adjusted EBITDAX by segment to the GAAP financial measure of income (loss) before income taxes for the three and nine months ended September 30, 2019 and 2018 (in thousands).

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2019	2018	2019	2018
Reconciliation of Adjusted EBITDAX to Income Before Income Taxes				
Exploration and production segment EBITDAX	$ 158,523	$ 170,004	$ 426,571	$ 463,415
Gathering and facilities segment EBITDAX	(622)	(601)	(1,168)	102
Subtotal of Reportable Segments	$ 157,901	$ 169,403	$ 425,403	$ 463,517
Less:				
Depletion, depreciation, amortization and accretion	$ (114,996)	$ (107,315)	$ (352,134)	$ (310,296)
Impairment of long lived assets	—	(16,166)	(11,233)	(16,294)
Exploration expenses	(13,245)	(11,038)	(32,725)	(21,326)
Gain on sale of property and equipment and assets of unconsolidated subsidiary	1,011	83,559	1,329	143,461
Gain (loss) on commodity derivatives	87,956	(35,913)	39,383	(175,752)
Settlements on commodity derivative instruments	(16,101)	41,009	8,432	99,914
Premiums paid for derivatives that settled during the period	812	1,956	19,910	5,191
Stock-based compensation expense	(11,358)	(17,420)	(39,306)	(50,883)
Amortization of debt issuance costs	(974)	(935)	(3,799)	(12,303)
Make-whole premium on 2021 Senior Notes	—	—	—	(35,600)
Gain on repurchase of 2026 Senior Notes	—	—	10,486	—
Interest expense	(22,250)	(19,790)	(61,478)	(55,326)
Income Before Income Taxes	$ 68,756	$ 87,350	$ 4,268	$ 34,303

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, 2018 (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, 2019 and 2018.

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, as well as the design and support of midstream assets to gather and process crude oil and gas production focused in the DJ Basin.

Financial Results

For the three and nine months ended September 30, 2019, crude oil, natural gas and NGL sales, coupled with the impact of settled derivatives, decreased to $199.0 million and $599.3 million, respectively, as compared to $239.2 million and $667.5 million, respectively, in the same prior year periods due to a decrease of $7.43 and $6.58 in realized price per BOE, respectively, including settled derivatives, partially offset by an increase in sales volumes of 427 MBoe and 2,312 MBoe, respectively.

For the three and nine months ended September 30, 2019, we had net income of $48.2 million and net loss of $2.4 million, respectively, as compared to net income of $65.2 million and $22.0 million for the three and nine months ended September 30, 2018, respectively. The change in net income for the three months ended September 30, 2019 from the three months ended September 30, 2018 was primarily driven by a decrease in sales revenue of $85.2 million partially offset by an increase in commodity derivative gain of $123.9 million and an increase in operating expenses of $28.3 million excluding the gain on sale of property and equipment and assets of unconsolidated subsidiary of $82.5 million. The change to net loss for the nine months ended September 30, 2019 from net income for the nine months ended September 30, 2018 was primarily driven by a decrease in sales revenues of $131.6 million and a decrease in interest expense of $48.4 million related to redemption of the Company's 2021 Senior Notes during the nine months ended September 30, 2018 partially offset by an increase in operating expenses of $162.2 million and an increase in the commodity derivative gain of $215.1 million.

Adjusted EBITDAX was $157.9 million and $425.4 million for the three and nine months ended September 30, 2019, respectively, as compared to $169.4 million and $463.5 million for the three and nine months ended September 30, 2018, respectively, reflecting a 6.8% and an 8.2% decrease, 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, 2019, our aggregate drilling, completion, and leasehold capital expenditures, totaled $135.0 million, of which $122.3 million was drilling and completion additions and $12.7 million was leasehold and surface acreage additions. This excludes the impact of the decrease in outstanding elections of $3.9 million. In addition, Elevation Midstream, LLC, our wholly owned midstream subsidiary, incurred $65.1 million of capital expenditures during the three months ended September 30, 2019. These capital expenditures are funded entirely pursuant to the Elevation Midstream, LLC Securities Purchase Agreement.

During the three months ended September 30, 2019, we drilled 27 gross (20.0 net) wells with an average length of approximately 10,900 feet and completed 37 gross (31.2 net) wells with an average lateral length of approximately 8,900 feet. We turned to sales 22 gross (17.7 net) wells with an average lateral length of approximately 9,500 feet.

Recent Developments

Senate Bill 19-181 "Protect Public Welfare Oil And Gas Operations"

On April 16, 2019, Senate Bill 19-181 ("SB181") became law, increasing the regulatory authority of local governments in Colorado over the surface impacts of oil and gas development in a reasonable manner. Among other things, SB181 (i) repeals a prior law restricting local government land use authority over oil and gas mineral extraction areas to areas designated by the Colorado Oil and Gas Conservation Commission, (ii) directs the Colorado Air Quality Control Commission to review its leak detection and repair rules and to adopt rules to minimize emissions of certain air pollutants, (iii) clarifies that local governments have authority to regulate the siting of oil and gas locations in a reasonable manner, including the ability to inspect oil and gas facilities, impose fines for leaks, spills, and emissions, and impose fees on operators or owners to cover regulation and enforcement costs, (iv) allows local governments or oil and gas operators to request a technical review board to evaluate the effect of the local government's preliminary or final determination on the operator's application and (v) repeals an exemption for oil and gas production from counties' authority to regulate noise. Although industry trade associations opposed SB181, management believes that Extraction can continue to successfully operate our business. However, the enactment of SB181 could lead to delays and additional costs to our business.

Aurora and Commerce City Operator Agreements

Extraction entered into operator agreements with the city of Aurora and Commerce City on July 8, 2019 and September 18, 2019, respectively. The agreements established a framework for the permitting process and Extraction's Best Management Practices while operating within the cities, including electric drilling rigs and quiet hydraulic fracturing fleets. They also identified the wells to be drilled through year-end 2025 and 2024, respectively.

Rocky Mountain Midstream East Greeley Pipeline and Auburn Compressor

On October 14, 2019, Rocky Mountain Midstream commenced service on its East Greeley Pipeline and Auburn Compressor Station. This pipeline and compressor station enables us to flow our oil and gas from parts of our East Greeley area without the bottlenecks or constraints we have historically experienced in this area.

Badger Central Gathering Facility

On October 3, 2019, Elevation commenced moving crude oil, natural gas and water through its Badger central gathering facility, which enables Extraction to efficiently transport its crude oil and natural gas production along with water used during the completion process. The use of this gathering facility allows for the elimination of oil or water storage on the well pad site and reduces truck traffic, which minimizes the impact to the surrounding environment and communities.

Western Gas Outage

During portions of August and September 2019, Extraction’s production on Western Gas' gathering system was significantly curtailed due to an unplanned outage at their Lancaster gas plant. We estimate our third quarter production was negatively impacted by this outage by approximately 8,304 BOE/d. This plant resumed normal operations in October 2019.

November 2019 Credit Facility Amendment

On November 4, 2019, we amended its revolving credit facility to decrease the borrowing base from $1.1 billion to $950.0 million, associated with the scheduled borrowing base redetermination. The current elected commitments were also decreased to $950.0 million.

August 2019 Divestiture

On August 22, 2019, we completed the sale of certain non-operated producing properties for aggregate sales proceeds of approximately $22.0 million, subject to customary purchase price adjustments. No gain or loss was recognized for the August 2019 Divestiture. We continue to explore divestitures, as part of our ongoing initiative to divest of non-strategic assets.

Elevation Preferred Units

On July 10, 2019, Elevation closed on an additional 100,000 Elevation Preferred Units under an existing securities purchase agreement with a third party, pursuant to which Elevation had agreed to sell an additional 100,000 Elevation Preferred Units at a price of $990 per Elevation Preferred Unit with an aggregate liquidation preference of $100.0 million, and resulting in net proceeds of approximately $96.5 million, after deducting discounts and related offering expenses. These Elevation Preferred Units are non-recourse to Extraction.

August 2019 Credit Facility Amendment

In August 2019, we amended its revolving credit facility to increase the elected commitments from $900.0 million to $1.0 billion.

June 2019 Credit Facility Amendment

On June 26, 2019, we amended our revolving credit facility to (i) increase the elected commitments from $650.0 million to $900.0 million, (ii) increase the amount for permitted letters of credit from $50.0 million to $100.0 million and increase the letter of credit sublimit for the Company's oil marketer from $35.0 million to $40.0 million, (iii) decrease the borrowing base from $1.2 billion to $1.1 billion and (iv) increase the limitation on permitted investments from $15.0 million to $20.0 million.

Senior Notes Repurchase Program

On January 4, 2019, our Board of Directors authorized a program, subject to the amendment to our revolving credit facility, to repurchase up to $100.0 million of our Senior Notes (“Senior Notes Repurchase Program”). Our Senior Notes Repurchase Program is subject to restrictions under our Credit Facility and does not obligate us to acquire any specific nominal amount of Senior Notes. During the nine months ended September 30, 2019, we repurchased a nominal value of $49.8 million for $39.3 million in connection with the Senior Notes Repurchase Program.

Stock Repurchase Program

On November 19, 2018, we announced the Board of Directors had authorized a program to repurchase up to $100.0 million of our common stock ("Stock Repurchase Program"). On April 1, 2019, the Company announced the Board of Directors had authorized an extension and increase in our ongoing Stock Repurchase Program bringing the total amount authorized to $163.2 million ("Extended Stock Repurchase Program"). Prior to commencing the Extended Stock Repurchase Program, the Company had purchased approximately 13.0 million shares of its common stock for $63.2 million under the Stock Repurchase Program, which repurchases were completed in the third quarter of 2019, bringing the total amount of common stock repurchased to $163.2 million and completing the Extended Stock Repurchase Program. During the three and nine months ended September 30, 2019, the Company repurchased approximately 4.8 million and 34.1 million shares of its common stock for $21.2 million and $136.9 million, respectively.

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, 2019, our revenues were derived 87% from oil sales, 8% from natural gas sales and 5% from NGL sales. 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 nine months ended September 30, 2019, our revenues were derived 81% from oil sales, 12% from natural gas sales and 7% 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. 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 the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2019	2018	2019	2018
Oil (MBbl)	3,597	3,618	10,830	10,394
Natural gas (MMcf)	14,418	11,838	43,433	33,612
NGL (MBbl)	1,390	1,372	4,097	3,860
Total (MBoe)	7,390	6,963	22,167	19,855
Average net sales (BOE/d)	80,327	75,680	81,198	72,731

As reservoir pressures decline, production from a given well or formation decreases. Growth in our future production and reserves will depend on our ability to continue to add or develop 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, 2019, 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 also during 2018 and 2019 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. Also affecting the differential is the processing fee deduction retained by the natural gas processing plant, generally in the form of percentage of proceeds. The price we receive for our natural gas produced in the 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,	
	2019	2018	2019	2018
Oil				
NYMEX WTI High ($/Bbl)	$ 62.90	$ 74.14	$ 66.30	$ 74.15
NYMEX WTI Low ($/Bbl)	$ 51.09	$ 65.01	$ 46.54	$ 59.19
NYMEX WTI Average ($/Bbl)	$ 56.44	$ 69.43	$ 57.10	$ 66.79
Average Realized Price ($/Bbl)	$ 47.56	$ 62.32	$ 48.16	$ 59.58
Average Realized Price, with derivative settlements ($/Bbl)	$ 47.45	$ 50.02	$ 44.39	$ 48.23
Average Realized Price as a % of Average NYMEX WTI	84.3 %	89.8 %	84.3 %	89.2 %
Differential ($/Bbl) to Average NYMEX WTI (1)	$ (8.28)	$ (7.11)	$ (8.74)	$ (7.21)
Natural Gas				
NYMEX Henry Hub High ($/MMBtu)	$ 2.68	$ 3.08	$ 3.59	$ 3.63
NYMEX Henry Hub Low ($/MMBtu)	$ 2.07	$ 2.72	$ 2.07	$ 2.55
NYMEX Henry Hub Average ($/MMBtu)	$ 2.33	$ 2.86	$ 2.56	$ 2.85
NYMEX Henry Hub Average converted to a $/Mcf basis (factor of 1.1 to 1)	$ 2.56	$ 3.15	$ 2.82	$ 3.14
Average Realized Price ($/Mcf)	$ 1.17	$ 1.95	$ 1.71	$ 1.99
Average Realized Price, with derivative settlements ($/Mcf)	$ 1.33	$ 2.08	$ 1.69	$ 2.37
Average Realized Price as a % of Average NYMEX Henry Hub(1)	45.7 %	61.9 %	60.6 %	63.4 %
Differential ($/Mcf) to Average NYMEX Henry Hub	$ (1.39)	$ (1.20)	$ (1.11)	$ (1.15)
NGL				
Average Realized Price ($/Bbl)	$ 6.55	$ 24.49	$ 10.97	$ 22.38
Average Realized Price as a % of Average NYMEX WTI	11.6 %	35.3 %	19.2 %	33.5 %
BOE				
Average Realized Price per BOE	$ 26.65	$ 40.53	$ 28.91	$ 38.91
Average Realized Price per BOE with derivative settlements	$ 26.92	$ 34.35	$ 27.04	$ 33.62

(1) Excludes the unrealized impact of estimated payments associated with a minimum volume commitment pursuant to ASC 606, Revenue Recognition that may be incurred by our oil marketer.

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. For a summary of the Company's commodity derivative contracts as of September 30, 2019, please see *Note 5—Commodity Derivative Instruments* in Part 1, Item 1 of this Quarterly Report.

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, 2019	2018
NYMEX WTI Crude Swaps:		
Notional volume (Bbl)	5,580,000	4,000,000
Weighted average fixed price ($/Bbl)	$ 52.55	$ 51.23
NYMEX WTI Crude Purchased Puts:		
Notional volume (Bbl)	15,800,000	10,077,600
Weighted average purchased put price ($/Bbl)	$ 46.59	$ 43.70
NYMEX WTI Crude Purchased Calls:		
Notional volume (Bbl)	14,000,000	1,740,000
Weighted average purchased call price ($/Bbl)	$ 64.99	$ 58.90
NYMEX WTI Crude Sold Calls:		
Notional volume (Bbl)	17,750,000	6,730,000
Weighted average sold call price ($/Bbl)	$ 63.69	$ 57.14
NYMEX WTI Crude Sold Puts:		
Notional volume (Bbl)	15,300,000	10,088,800
Weighted average sold put price ($/Bbl)	$ 44.33	$ 38.80
NYMEX HH Natural Gas Swaps:		
Notional volume (MMBtu)	23,400,000	30,750,000
Weighted average fixed price ($/MMBtu)	$ 2.83	$ 3.12
NYMEX HH Natural Gas Purchased Puts:		
Notional volume (MMBtu)	3,600,000	1,800,000
Weighted average purchased put price ($/MMBtu)	$ 3.04	$ 3.00
NYMEX HH Natural Gas Sold Calls:		
Notional volume (MMBtu)	3,600,000	1,800,000
Weighted average sold call price ($/MMBtu)	$ 3.46	$ 3.15
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)	31,100,000	26,895,000
Weighted average fixed basis price ($/MMBtu)	$ (0.73)	$ (0.59)
Total Amounts Received/(Paid) from Settlement (in thousands)	$ (8,432)	$ (99,914)
Cash provided by changes in Accounts Receivable and Accounts Payable related to Commodity Derivatives	$ (10,095)	$ 6,432
Cash Settlements on Commodity Derivatives per Consolidated Statements of Cash Flows	$ (18,527)	$ (93,482)

Lease Operating Expenses

All direct and allocated indirect costs of lifting hydrocarbons from a producing formation to the surface constitutes 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 or drilling or completion expenses.

Capital Expenditures

For the nine months ended September 30, 2019, we incurred approximately $472.0 million in drilling and completion capital expenditures, excluding the impact of a decrease in outstanding elections of $7.9 million. For the nine months ended September 30, 2019, we drilled 91 gross (74.57 net) wells with an average lateral length of approximately 9,100 feet and completed 113 gross (98.17 net) wells with an average lateral length of approximately 8,700 feet. We turned to sales 65 gross (56.7 net) wells with an average lateral length of approximately 8,000 feet. In addition, we incurred approximately $44.5 million of leasehold and surface acreage additions, excluding the impact of the increase in outstanding elections of $3.0 million. In addition, Elevation Midstream, LLC, our wholly owned midstream subsidiary, incurred $192.6 million of capital expenditures during the nine months ended September 30, 2019. These capital expenditures are funded entirely pursuant to the Elevation Midstream, LLC Securities Purchase Agreement.

In October 2019, we revised our 2019 capital budget for the drilling and completion of operated and non-operated wells from a range of $585.0 million to $675.0 million to approximately $520.0 million to $550.0 million. We intend to allocate substantially all our capital budget to the Core DJ Basin. We expected to drill 125 gross operated wells, complete 122 gross operated wells and turn-in-line 111 gross operated wells. As a result of the change in our capital budget, we expect to drill 108 gross operated wells, complete 118 gross operated wells and turn-in-line 113 gross operated wells. Our capital budget still anticipates a one to two operated rig drilling program and excludes up to $250.0 million for Elevation, which is fully funded by a third party and any amounts that may be paid for potential acquisitions.

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

Adjusted EBITDAX

Adjusted EBITDAX is not a measure of net income (loss) as determined by United States generally accepted accounting principles ("GAAP"). Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDAX as net income (loss) adjusted for certain cash and non-cash items, including depletion, depreciation, amortization and accretion ("DD&A"), impairment of long lived assets, exploration expenses, gain on sale of property and equipment and assets of unconsolidated subsidiary, (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, gain on repurchase of notes, interest expense, income tax expense (benefit) and non-recurring charges. Adjusted EBITDAX is also used to evaluate the performance of reportable segments. See *Note 13 - Segment Information* in Item 8 in this Quarterly Report for more information regarding the EBITDAX of reportable segments.

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 (i) 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; (ii) 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 (iii) 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,	
	2019	2018	2019	2018
Reconciliation of Net Income (Loss) to Adjusted EBITDAX:				
Net income (loss)	$ 48,156	$ 65,150	$ (2,432)	$ 22,003
Add back:				
Depletion, depreciation, amortization and accretion	114,996	107,315	352,134	310,296
Impairment of long lived assets	—	16,166	11,233	16,294
Exploration expenses	13,245	11,038	32,725	21,326
Gain on sale of property and equipment and assets of unconsolidated subsidiary	(1,011)	(83,559)	(1,329)	(143,461)
(Gain) loss on commodity derivatives	(87,956)	35,913	(39,383)	175,752
Settlements on commodity derivative instruments	16,101	(41,009)	(8,432)	(99,914)
Premiums paid for derivatives that settled during the period	(812)	(1,956)	(19,910)	(5,191)
Stock-based compensation expense	11,358	17,420	39,306	50,883
Amortization of debt issuance costs	974	935	3,799	12,303
Make-whole premium on 2021 Senior Notes	—	—	—	35,600
Gain on repurchase of 2026 Senior Notes	—	—	(10,486)	—
Interest expense	22,250	19,790	61,478	55,326
Income tax expense	20,600	22,200	6,700	12,300
Adjusted EBITDAX	$ 157,901	$ 169,403	$ 425,403	$ 463,517

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 January 1, 2019, we adopted ASC 842 - *Leases*. We adopted using the modified retrospective transition approach to apply the new standard to all leases entered into on or after January 1, 2019 and all existing leases. ASC 842 supersedes previous lease recognition requirements in ASC 840 and resulted in the recognition of $20.5 million of right-of-use assets and $26.1 million of lease liabilities on the condensed consolidated balance sheet as of September 30, 2019. See *"Part I, Item 1, Note 2—Basis of Presentation, Significant Accounting Policies and Recent Accounting Pronouncements—Leases"* for additional information.

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,	
	2019	2018	2019	2018
	(Unaudited)			
Revenues:				
Oil sales	$ 171,074	$ 225,467	$ 521,623	$ 619,211
Natural gas sales	16,801	23,103	74,385	66,991
NGL sales	9,099	33,590	44,940	86,369
Total Revenues	196,974	282,160	640,948	772,571
Operating Expenses:				
Lease operating expenses	22,979	20,283	68,445	61,760
Transportation and gathering	6,922	11,786	29,142	29,284
Production taxes	9,711	21,605	46,419	66,317
Exploration expenses	13,245	11,038	32,725	21,326
Depletion, depreciation, amortization and accretion	114,996	107,315	352,134	310,296
Impairment of long lived assets	—	16,166	11,233	16,294
Gain on sale of property and equipment and assets of unconsolidated subsidiary	(1,011)	(83,559)	(1,329)	(143,461)
General and administrative expenses	27,445	35,365	85,835	100,565
Total Operating Expenses	194,287	139,999	624,604	462,381
Operating Income	2,687	142,161	16,344	310,190
Other Income (Expense):				
Commodity derivatives gain (loss)	87,956	(35,913)	39,383	(175,752)
Interest expense	(23,224)	(20,725)	(54,791)	(103,229)
Other income	1,337	1,827	3,332	3,094
Total Other Income (Expense)	66,069	(54,811)	(12,076)	(275,887)
Income Before Income Taxes	68,756	87,350	4,268	34,303
Income tax expense	(20,600)	(22,200)	(6,700)	(12,300)
Net Income (Loss)	$ 48,156	$ 65,150	$ (2,432)	$ 22,003

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, 2019	For the Three Months Ended September 30, 2018	For the Nine Months Ended September 30, 2019	For the Nine Months Ended September 30, 2018
Sales (MBoe):	7,390	6,963	22,167	19,855
Oil sales (MBbl)	3,597	3,618	10,830	10,394
Natural gas sales (MMcf)	14,418	11,838	43,433	33,612
NGL sales (MBbl)	1,390	1,372	4,097	3,860
Sales (BOE/d):	80,327	75,680	81,198	72,731
Oil sales (Bbl/d)	39,098	39,323	39,670	38,072
Natural gas sales (Mcf/d)	156,717	128,679	159,095	123,122
NGL sales (Bbl/d)	15,109	14,910	15,007	14,138
Average sales prices[1]:				
Oil sales (per Bbl)	$ 47.56	$ 62.32	$ 48.16	$ 59.58
Oil sales with derivative settlements (per Bbl)	47.45	50.02	44.39	48.23
Natural gas sales (per Mcf)	1.17	1.95	1.71	1.99
Natural gas sales with derivative settlements (per Mcf)	1.33	2.08	1.69	2.37
NGL sales (per Bbl)	6.55	24.49	10.97	22.38
Average price (per BOE)	26.65	40.53	28.91	38.91
Average price with derivative settlements (per BOE)	26.92	34.35	27.04	33.62
Expense per BOE:				
Lease operating expenses	$ 3.11	$ 2.91	$ 3.09	$ 3.11
Transportation and gathering	0.94	1.69	1.31	1.47
Production taxes	1.31	3.10	2.09	3.34
Exploration expenses	1.79	1.59	1.48	1.07
Depletion, depreciation, amortization and accretion	15.56	15.41	15.89	15.63
Impairment of long lived assets	—	2.32	0.51	0.82
General and administrative expenses	3.71	5.08	3.87	5.06
Cash general and administrative expenses	2.18	2.58	2.10	2.50
Stock-based compensation	1.54	2.50	1.77	2.56
Total operating expenses per BOE	$ 26.42	$ 32.10	$ 28.24	$ 30.50

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

Three Months Ended September 30, 2019 Compared to Three Months Ended September 30, 2018

Oil sales revenues. Crude oil sales revenues decreased by $54.4 million to $171.1 million for the three months ended September 30, 2019 as compared to crude oil sales of $225.5 million for the three months ended September 30, 2018. A decrease in sales volumes between these periods contributed a $1.4 million negative impact, and a decrease in crude oil prices contributed a $53.1 million negative impact.

For the three months ended September 30, 2019, our crude oil sales averaged 39.1 MBbl/d. Our crude oil sales volume decreased by 1% to 3,597 MBbl for the three months ended September 30, 2019 compared to 3,618 MBbl for the three months ended September 30, 2018. The volume decrease is primarily due to the natural decline of our existing properties, partially offset by an increase in production from the completion of 133 gross wells from October 1, 2018 to September 30, 2019.

The average price we realized on the sale of crude oil was $47.56 per Bbl for the three months ended September 30, 2019 compared to $62.32 per Bbl for the three months ended September 30, 2018, primarily due to changes in market prices for crude oil that negatively impacted the realized price.

Natural gas sales revenues. Natural gas sales revenues decreased by $6.3 million to $16.8 million for the three months ended September 30, 2019 as compared to natural gas sales revenues of $23.1 million for the three months ended September 30, 2018. An increase in sales volumes between these periods contributed a $5.0 million positive impact, while a decrease in natural gas prices contributed a $11.3 million negative impact.

For the three months ended September 30, 2019, our natural gas sales averaged 156.7 MMcf/d. Natural gas sales volumes increased by 22% to 14,418 MMcf for the three months ended September 30, 2019 as compared to 11,838 MMcf for the three months ended September 30, 2018. The volume increase is primarily due to the completion of 133 gross wells from October 1, 2018 to September 30, 2019, partially offset by the natural decline on existing producing properties.

The average price we realized on the sale of our natural gas was $1.17 per Mcf for the three months ended September 30, 2019 compared to $1.95 per Mcf for the three months ended September 30, 2018, primarily due to capacity constraints in transporting the wet gas associated with crude oil production coupled with negative market conditions surrounding limited export capacity.

NGL sales revenues. NGL sales revenues decreased by $24.5 million to $9.1 million for the three months ended September 30, 2019 as compared to NGL sales revenues of $33.6 million for the three months ended September 30, 2018. An increase in sales volumes between these periods contributed a $0.4 million positive impact, while a decrease in price contributed a $24.9 million negative impact.

For the three months ended September 30, 2019, our NGL sales averaged 15.1 MBbl/d. NGL sales volumes increased by 1% to 1,390 MBbl for the three months ended September 30, 2019 as compared to 1,372 MBbl for the three months ended September 30, 2018. The volume increase is primarily due to the completion of 133 gross wells from October 1, 2018 to September 30, 2019, 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 $6.55 per Bbl for the three months ended September 30, 2019 compared to $24.49 per Bbl for the three months ended September 30, 2018, primarily due to capacity constraints in transporting the wet gas associated with crude oil production coupled with negative market conditions surrounding limited export capacity.

Lease operating expenses ("LOE"). Our LOE increased by $2.7 million to $23.0 million for the three months ended September 30, 2019, from $20.3 million for the three months ended September 30, 2018. The increase in LOE was primarily the result of an increase in producing wells and an increase in workover repairs, partially offset by optimization of our field cost structure during the twelve months ended September 30, 2019.

On a per unit basis, LOE increased to $3.11 per BOE sold for the three months ended September 30, 2019 from $2.91 per BOE for the three months ended September 30, 2018.

Transportation and gathering ("T&G"). Our T&G expense decreased by $4.9 million to $6.9 million for the three months ended September 30, 2019, from $11.8 million for the three months ended September 30, 2018. The decrease in T&G

was primarily due to a decrease of volumes on a certain gathering system during the three months ended September 30, 2019 compared to the three months ended September 30, 2018.

On a per unit basis, T&G decreased to $0.94 per BOE sold for the three months ended September 30, 2019 compared to $1.69 per BOE sold for the three months ended September 30, 2018.

Production taxes. Our production taxes decreased by $11.9 million to $9.7 million for the three months ended September 30, 2019 as compared to $21.6 million for the three months ended September 30, 2018. The decrease is primarily attributable to decreased revenue as production taxes are calculated as a percentage of sales revenue. Production taxes as a percentage of sales revenue was 4.9% for the three months ended September 30, 2019 as compared to 7.7% for the three months ended September 30, 2018. The decrease in production taxes as a percentage of sales revenue relates to a decrease in the estimated ad valorem and severance tax rates and an adjustment to the estimated ad valorem tax payable for the three months ended September 30, 2019.

Exploration expenses. Our exploration expenses were $13.2 million for the three months ended September 30, 2019, which were primarily attributable to $0.5 million in expense for the extension of certain leases and $11.2 million in impairment expense related to the abandonment and impairment of unproved properties for the three months ended September 30, 2019. For the three months ended September 30, 2018, we recognized $11.0 million in exploration expenses.

Depletion, depreciation, amortization and accretion expense ("DD&A"). Our DD&A expense increased $7.7 million to $115.0 million for the three months ended September 30, 2019 as compared to $107.3 million for the three months ended September 30, 2018. This increase is due to an increase in volumes sold for the three months ended September 30, 2019 as sales increased by approximately 427 MBoe. On a per unit basis, DD&A expense increased to $15.56 per BOE for the three months ended September 30, 2019 from $15.41 per BOE for the three months ended September 30, 2018.

Impairment of long lived assets. No impairment expense was recognized for the three months ended September 30, 2019. Impairment expense of $16.2 million expense was recognized for the three months ended September 30, 2018 related to impairment of the proved oil and gas properties in our northern field.

Gain 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 $1.0 million for the three months ended September 30, 2019. Our gain on sale of property and equipment and assets of unconsolidated subsidiary was $83.6 million related to our August 2018 Divestiture for the three months ended September 30, 2018.

General and administrative expenses ("G&A"). General and administrative expenses decreased by $8.0 million to $27.4 million for the three months ended September 30, 2019 as compared to $35.4 million for the three months ended September 30, 2018. This decrease is primarily due to a decrease in stock-based compensation expense recognized for the three months ended September 30, 2019 compared to the three months ended September 30, 2018. On a per unit basis, G&A expense decreased to $3.71 per BOE sold for the three months ended September 30, 2019 from $5.08 per BOE sold for the three months ended September 30, 2018.

Our G&A expenses for the three months ended September 30, 2019 includes $1.9 million related to the terms of a separation agreement with a former executive officer. No expenses of this nature were incurred during the three months ended September 30, 2018.

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, 2019 and 2018, stock-based compensation expense was $11.4 million and $17.4 million, respectively.

Commodity derivative gain (loss). Primarily due to the decrease in NYMEX crude oil futures prices at September 30, 2019 as compared to June 30, 2019 and change in fair value from the execution of new positions, we incurred a net gain on our commodity derivatives of $88.0 million for the three months ended September 30, 2019, including the amortization of premiums. 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. 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, 2019, we received cash settlements of commodity derivatives totaling $16.1 million. During the three months ended September 30, 2018, we paid cash settlements of commodity derivatives totaling $41.0 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, 2019, we recognized interest expense of $23.2 million as compared to $20.7 million for the three months ended September 30, 2018, as a result of borrowings under our revolving credit facility, our 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, 2019 of $23.8 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, 2018 of approximately $21.5 million related to our revolving credit facility, our 2024 Senior Notes, and our 2026 Senior Notes. Also included in interest expense for the three months ended September 30, 2019 and 2018 was the amortization of debt issuance costs of $1.0 million and $0.9 million, respectively. For the three months ended September 30, 2019 and 2018, we capitalized interest expense of $1.6 million and $1.7 million, respectively.

Income tax expense. We recorded an income tax expense of $20.6 million and $22.2 million for the three months ended September 30, 2019 and 2018, respectively. This resulted in an effective tax rate of approximately 30.0% and 25.4% for the three months ended September 30, 2019 and 2018, respectively. Our effective tax rate for the three months ended September 30, 2019 and 2018 differs from the U.S. statutory income tax rates of 21.0% primarily due to the effects of state income taxes and estimated taxable permanent differences.

Gathering and facilities segment. The Company has two operating segments, (i) the exploration, development and production of oil, natural gas and NGL (the "exploration and production segment") and (ii) the construction and support of midstream assets to gather and process crude oil and gas production (the "gathering and facilities segment"). Prior to the fourth quarter of 2018, the Company had a single operating segment. The gathering systems and facilities operating segment was under development as of September 30, 2019. On October 3, 2019, Elevation commenced moving crude oil, natural gas and water through its Badger central gathering facility. Capital expenditures associated with gathering systems and facilities were incurred to develop midstream infrastructure to support the Company's development of its oil and gas leasehold along with third-party activity and amounted to $65.1 million and $37.5 million for the three months ended September 30, 2019 and 2018, respectively.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

Oil sales revenues. Crude oil sales revenues decreased by $97.6 million to $521.6 million for the nine months ended September 30, 2019 as compared to crude oil sales of $619.2 million for the nine months ended September 30, 2018. An increase in sales volumes between these periods contributed a $26.0 million positive impact, while a decrease in crude oil prices contributed a $123.6 million negative impact.

For the nine months ended September 30, 2019, our crude oil sales averaged 39.7 MBbl/d. Our crude oil sales volume increased 4% to 10,830 MBbl for the nine months ended September 30, 2019 compared to 10,394 MBbl for the nine months ended September 30, 2018. The volume increase is primarily due to an increase in production from the completion of 133 gross wells from October 1, 2018 to September 30, 2019, partially offset by the natural decline of our existing properties.

The average price we realized on the sale of crude oil was $48.16 per Bbl for the nine months ended September 30, 2019 compared to $59.58 per Bbl for the nine months ended September 30, 2018, primarily due to changes in market prices for crude oil that negatively impacted the realized price.

Natural gas sales revenues. Natural gas sales revenues increased by $7.4 million to $74.4 million for the nine months ended September 30, 2019 as compared to natural gas sales revenues of $67.0 million for the nine months ended September 30, 2018. An increase in sales volumes between these periods contributed a $19.5 million positive impact, while a decrease in natural gas prices contributed a $12.1 million negative impact.

For the nine months ended September 30, 2019, our natural gas sales averaged 159.1 MMcf/d. Natural gas sales volumes increased by 29% to 43,433 MMcf for the nine months ended September 30, 2019 as compared to 33,612 MMcf for the nine months ended September 30, 2018. The volume increase is primarily due to the completion of 133 gross wells from October 1, 2018 to September 30, 2019, partially offset by the natural decline on existing producing properties.

The average price we realized on the sale of our natural gas was $1.71 per Mcf for the nine months ended September 30, 2019 compared to $1.99 per Mcf for the nine months ended September 30, 2018, primarily due to capacity constraints in transporting the wet gas associated with crude oil production coupled with negative market conditions surrounding limited export capacity.

NGL sales revenues. NGL sales revenues decreased by $41.5 million to $44.9 million for the nine months ended September 30, 2019 as compared to NGL sales revenues of $86.4 million for the nine months ended September 30, 2018. An increase in sales volumes between these periods contributed a $5.3 million positive impact, while a decrease in price contributed a $46.7 million negative impact.

For the nine months ended September 30, 2019, our NGL sales averaged 15.0 MBbl/d. NGL sales volumes increased by 6% to 4,097 MBbl for the nine months ended September 30, 2019 as compared to 3,860 MBbl for the nine months ended September 30, 2018. The volume increase is primarily due to the completion of 133 gross wells from October 1, 2018 to September 30, 2019, 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 $10.97 per Bbl for the nine months ended September 30, 2019 compared to $22.38 per Bbl for the nine months ended September 30, 2018, primarily due to capacity constraints in transporting the wet gas associated with crude oil production coupled with negative market conditions surrounding limited export capacity.

Lease operating expenses. Our LOE increased by $6.6 million to $68.4 million for the nine months ended September 30, 2019, from $61.8 million for the nine months ended September 30, 2018. The increase in LOE was primarily the result of an increase in producing wells and an increase in workover repairs, partially offset by optimization of our field cost structure during the twelve months ended September 30, 2019.

On a per unit basis, LOE decreased to $3.09 per BOE sold for the nine months ended September 30, 2019 from $3.11 per BOE for the nine months ended September 30, 2018. The decrease in LOE per BOE is primarily a result of increased production volumes during the nine months ended September 30, 2019.

Transportation and gathering. Our T&G expense decreased by $0.2 million to $29.1 million for the nine months ended September 30, 2019, from $29.3 million for the nine months ended September 30, 2018. The decrease in T&G was primarily due to a decrease of volumes on a certain gathering system for the nine months ended September 30, 2019.

On a per unit basis, T&G decreased to $1.31 per BOE sold for the nine months ended September 30, 2019 compared to $1.47 per BOE sold for the nine months ended September 30, 2018.

Production taxes. Our production taxes decreased by $19.9 million to $46.4 million for the nine months ended September 30, 2019 as compared to $66.3 million for the nine months ended September 30, 2018. The decrease is primarily attributable to decreased revenue as production taxes are calculated as a percentage of sales revenue. Production taxes as a percentage of sales revenue was 7.2% for the nine months ended September 30, 2019 as compared to 8.6% for the nine months ended September 30, 2018. The decrease in production taxes as a percentage of sales revenue relates to a decrease in the estimated ad valorem and severance tax rates and an adjustment to the estimated ad valorem tax payable for the nine months ended September 30, 2019.

Exploration expenses. Our exploration expenses were $32.7 million for the nine months ended September 30, 2019, which were primarily attributable to $2.0 million in expense for the extension of certain leases and $26.2 million in impairment expense related to the abandonment and impairment of unproved properties for the nine months ended September 30, 2019. For the nine months ended September 30, 2018, we recognized $21.3 million in exploration expenses.

Depletion, depreciation, amortization and accretion expense. Our DD&A expense increased $41.8 million to $352.1 million for the nine months ended September 30, 2019 as compared to $310.3 million for the nine months ended September 30, 2018. This increase is due to an increase in volumes sold for the nine months ended September 30, 2019 as sales increased by approximately 2,312 MBoe. On a per unit basis, DD&A expense increased to $15.89 per BOE for the nine months ended September 30, 2019 from $15.63 per BOE for the nine months ended September 30, 2018.

Impairment of long lived assets. Our impairment expense of $11.2 million for the nine months ended September 30, 2019 was related to impairment of the proved oil and gas properties in our northern field. The fair value did not exceed our carrying amount associated with the proved oil and gas properties in our northern field. Impairment expense of $16.3 million was recognized for the nine months ended September 30, 2018.

Gain on sale of property and equipment and assets of unconsolidated subsidiary. Our gain on sale of property and equipment and assets of unconsolidated subsidiary for the nine months ended September 30, 2019 was $1.3 million. 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.

General and administrative expenses. General and administrative expenses decreased by $14.8 million to $85.8 million for the nine months ended September 30, 2019 as compared to $100.6 million for the nine months ended September 30, 2018. This decrease is primarily due to a decrease in stock-based compensation expense recognized for the nine months ended September 30, 2019 compared to the nine months ended September 30, 2018. On a per unit basis, G&A expense decreased to $3.87 per BOE sold for the nine months ended September 30, 2019 from $5.06 per BOE sold for the nine months ended September 30, 2018.

Our G&A expenses for the nine months ended September 30, 2019 includes $1.9 million related to the terms of a separation agreement with a former executive officer. No expenses of this nature were incurred during the nine months ended September 30, 2018.

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, 2019 and 2018, stock-based compensation expense was $39.3 million and $50.9 million, respectively.

Commodity derivative gain (loss). Primarily due to the decrease in NYMEX crude oil futures prices at September 30, 2019 as compared to December 31, 2018 and change in fair value from the execution of new positions, we incurred a net gain on our commodity derivatives of $39.4 million for the nine months ended September 30, 2019, including the amortization of premiums. 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, including the amortization of premiums. These 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, 2019 and 2018, we paid cash settlements of commodity derivatives totaling $8.4 million and $99.9 million, respectively.

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 nine months ended September 30, 2019, we recognized interest expense of $54.8 million as compared to $103.2 million for the nine months ended September 30, 2018, 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 nine months ended September 30, 2019 of $66.9 million related to our 2024 Senior Notes, 2026 Senior Notes, and revolving credit facility. We incurred interest expense for the nine months ended September 30, 2018 of approximately $61.6 million related to our revolving credit facility, our 2021 Senior Notes, 2024 Senior Notes, our 2026 Senior Notes, as well as a make-whole premium of $35.6 million related to our repayment of 2021 Senior Notes in January and February 2018. Also included in interest expense for the nine months ended September 30, 2019 and 2018 was the amortization of debt issuance costs of $3.8 million and $12.3 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 the 2021 Senior Notes. For the nine months ended September 30, 2019 and 2018, we capitalized interest expense of $5.4 million and $6.3 million, respectively. Interest expense for the nine months ended September 30, 2019 also includes $10.5 million of gain on debt extinguishment upon the repurchase of our 2026 Senior Notes.

Income tax expense. We recorded an income tax expense of $6.7 million and $12.3 million for the nine months ended September 30, 2019 and 2018, respectively. This resulted in an effective tax rate of approximately 156.8% and 35.9% for the nine months ended September 30, 2019 and 2018, respectively. Our effective tax rate for the nine months ended September 30, 2019 and 2018 differs from the U.S. statutory income tax rates of 21.0% primarily because of state income taxes and estimated taxable permanent differences. The primary differences between the tax rate of 156.8% and 35.9% for the nine months ended

September 30, 2019 and 2018, respectively, are the increase in estimated permanent differences during the nine months ended September 30, 2019 compared to the nine months ended September 30, 2018 and the pre-tax book income generated for the nine months ended September 30, 2019 compared to pre-tax book income for the nine months ended September 30, 2018.

Gathering and facilities segment. The Company has two operating segments, (i) the exploration, development and production of oil, natural gas and NGL (the "exploration and production segment") and (ii) the construction and support of midstream assets to gather and process crude oil and gas production (the "gathering and facilities segment"). Prior to the fourth quarter of 2018, the Company had a single operating segment. The gathering systems and facilities operating segment was under development as of September 30, 2019. On October 3, 2019, Elevation commenced moving crude oil, natural gas and water through its Badger central gathering facility. Capital expenditures associated with gathering systems and facilities are being incurred to develop midstream infrastructure to support the Company's development of its oil and gas leasehold along with third-party activity and amounted to $192.6 million and $57.2 million for the nine months ended September 30, 2019 and 2018, respectively.

Liquidity and Capital Resources

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

Historically, our primary sources of liquidity have been borrowings under our revolving credit facility, proceeds from notes offerings, 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 and divestitures. 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 $1,635.2 million and $1,417.7 million at September 30, 2019, and December 31, 2018, 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 may from time to time seek to retire or purchase our outstanding notes through cash purchases and/or exchanges (including for equity securities), in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

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.

In October 2019, we revised our 2019 capital budget for the drilling and completion of operated and non-operated wells from a range of $585.0 million to $675.0 million to approximately $520.0 million to $550.0 million. We intend to allocate substantially all our capital budget to the Core DJ Basin. We expected to drill 125 gross operated wells, complete 122 gross operated wells and turn-in-line 111 gross operated wells. As a result of the change in our capital budget, we expect to drill 108 gross operated wells, complete 118 gross operated wells and turn-in-line 113 gross operated wells. Our capital budget still anticipates a one to two operated rig drilling program and excludes up to $250.0 million for Elevation, which is fully funded by a third party and any amounts that may be paid for potential acquisitions.

The Company had a Stock Repurchase Program in place during the nine months ended September 30, 2019. Spending under this program during this time period was $136.9 million, and the total amount repurchased was $163.2 million which is the full amount authorized to be repurchased. The Company also has a Senior Notes Repurchase Program in place. Spending under this program during the nine months ended September 30, 2019 was $39.3 million. The Company was authorized to repurchase up to $100.0 million of its Senior Notes.

Cash Flows

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

	For the Nine Months Ended September 30,	
	2019	2018
Net cash provided by operating activities	$ 356,561	$ 468,362
Net cash used in investing activities	$ (706,868)	$ (678,133)
Net cash provided by financing activities	$ 173,049	$ 477,068

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

Net cash provided by operating activities. For the nine months ended September 30, 2019 as compared to the nine months ended September 30, 2018, our net cash provided by operating activities decreased by $111.8 million, primarily due to a decrease in operating revenues net of expenses of $119.0 million as a result of a decrease in commodity prices along with a decrease in cash of $88.4 million related to changes in working capital and an increase in cash paid for interest of $5.2 million. These decreases in net cash provided by operating activities were partially offset by a $75.0 million decrease in commodity derivative settlement payments.

Net cash used in investing activities. For the nine months ended September 30, 2019 as compared to the nine months ended September 30, 2018, our net cash used in investing activities increased by $28.7 million primarily due to increased spending of $127.8 million on our gathering systems and facilities, a $20.6 million increase in other property and equipment, a $30.4 million increase from the sale of property and equipment and a $16.5 million increase in spending on our investment in unconsolidated subsidiaries. Additionally, we did not receive $82.6 million in the current period from the sale of an unconsolidated subsidiary. These increases were offset by a decrease in spending on oil and gas property additions of $248.6 million for the nine months ended September 30, 2019.

Net cash provided by financing activities. For the nine months ended September 30, 2019 as compared to the nine months ended September 30, 2018, our net cash provided by financing activities decreased by $304.0 million as a result of a decrease of $739.7 million from the issuance of the 2026 Senior Notes, partially offset by an increase from redemption of the 2021 Senior Notes for $585.6 million. Net borrowings on the revolver increased $65.0 million offset by a $49.5 million decrease in the cash received from the issuance of Elevation Preferred Units compared to the nine months ended September 30, 2019. Additionally, there was an increase in cash spent to repurchase common stock of $133.3 million, as result of our Share Repurchase Program, and senior notes of $39.3 million, as a result of our Senior Note Repurchase Program during the nine months ended September 30, 2019.

Working Capital

Our working capital deficit was $202.6 million at September 30, 2019 and our surplus was $62.2 million at December 31, 2018. Our cash balances totaled $57.7 million and $235.0 million at September 30, 2019 and December 31, 2018, 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

As of September 30, 2019, our revolving credit facility has a maximum credit amount of $1.5 billion, subject to a borrowing base of $1.1 billion, subject to the current elected commitments of $1.0 billion, 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, and will depend on the volumes of our proved oil and gas reserves and estimated cash flows from these reserves and other information deemed relevant by the administrative agent under our revolving credit facility. As of September 30, 2019, the borrowing base was $1.1 billion, subject to current elected commitments of $1.0 billion.

On November 4, 2019, we amended our revolving credit facility to decrease the borrowing base from $1.1 billion to $950.0 million, associated with the scheduled borrowing base redetermination. The current elected commitments were also decreased to $950.0 million.

Principal amounts borrowed will be payable on the maturity date, and interest will be payable quarterly for alternate base rate loans and at the end of the applicable interest period for Eurodollar loans. We have a choice of borrowing in Eurodollars or at the alternate base rate. Eurodollar loans bear interest at a rate per annum equal to an adjusted LIBOR rate (equal to the product of: (a) the LIBOR rate, multiplied by (b) a fraction (expressed as a decimal), the numerator of which is the number one and the denominator of which is the number one minus the reserve percentages (expressed as a decimal) on such date at which the administrative agent under our revolving credit facility is required to maintain reserves on 'Eurocurrency Liabilities' as defined in and pursuant to Regulation D of the Board of Governors of the Federal Reserve System) plus an applicable margin ranging from 200 to 300 basis points, depending on the percentage of our borrowing base utilized. Alternate base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank's reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the adjusted one-month LIBOR rate (as calculated above) plus 100 basis points, plus an applicable margin ranging from 100 to 200 basis points, depending on the percentage of our borrowing base utilized. As of September 30, 2019, we had $550.0 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 our current and future subsidiaries, with the exception of Elevation. 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 and our restricted subsidiaries' consolidated current assets (includes unused commitments under our revolving credit facility and excludes derivative assets) to our restricted subsidiaries' 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% and 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 each 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

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 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. As of the date of this filing, we have repurchased 2026 Senior Notes with a nominal value of $49.8 million for $39.3 million in connection with the Senior Notes Repurchase Program.

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% per year (decreased proportionately to the extent such quarterly dividends are partially paid in cash). 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 the Series A Preferred Stock at a conversion ratio per share of Series A Preferred Stock of 61.9195, but only if the closing price of our common stock trades at or above a certain premium to our initial offering price, such premium to decrease with time. On October 15, 2019, the three year anniversary had passed for the Series A Preferred Stock to convert into our common stock. 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, 2019, $49.9 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 $250.0 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 $250.0 million commitment.

On July 10, 2019, Elevation closed on an additional 100,000 Elevation Preferred Units under an existing securities purchase agreement with a third party, pursuant to which Elevation had agreed to sell an additional 100,000 Elevation Preferred Units at a price of $990 per Elevation Preferred Unit with an aggregate liquidation preference of $100.0 million, and resulting in net proceeds of approximately $96.5 million, after deducting discounts and related offering expenses. These Elevation Preferred Units are non-recourse to Extraction. 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 31, 2023, subject to reductions if Extraction does not sell the full amount of additional Elevation Preferred Units to the Purchaser. By way of comparison, Extraction drilled a total of 161 wells during 2018 and 90 wells during the nine months ended September 30, 2019.

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

There were no changes to our critical accounting policies from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2018.

Recent Accounting Pronouncements

Please read *Note 2—Basis of Presentation, Significant Accounting Policies and Recent Accounting Pronouncements* 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, 2018, commodity prices increased during the first, second and third quarter, and subsequently decreased in the fourth quarter, while during the years ended December 31, 2017 and 2016, commodity prices generally increased. During the nine months ended September 30, 2019, commodity prices decreased compared to the same period in 2018. 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, 2019, we did not have material off-balance sheet arrangements, except for an 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, 2020, subject to an evergreen provision thereafter. 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. LIBOR is used as a reference rate for certain of our financial instruments, such as our revolving credit facility. LIBOR is set to be phased out at the end of 2021. We are currently reviewing how the LIBOR phase-out will affect the Company, but we do not expect the impact to be material.

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 and natural gas 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.

For a summary of the Company's commodity derivative contracts as of September 30, 2019, please see *Note 5—Commodity Derivative Instruments* in Part 1, Item 1 of this Quarterly Report.

As of September 30, 2019, the fair market value of our oil derivative contracts was a net asset of $95.2 million. Based on our open oil derivative positions at September 30, 2019, a 10% increase in the NYMEX WTI price would decrease our net oil derivative asset by approximately $92.4 million, while a 10% decrease in the NYMEX WTI price would increase our net oil derivative asset by approximately $84.1 million. As of September 30, 2019, the fair market value of our natural gas derivative contracts was a net asset of $12.6 million. Based upon our open commodity derivative positions at September 30, 2019, a 10% increase in the NYMEX Henry Hub price would decrease our net natural gas derivative asset by approximately $7.6 million, while a 10% decrease in the NYMEX Henry Hub price would increase our net natural gas derivative asset by approximately $7.6 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, 2019, 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, 2019, we had commodity derivative contracts with ten 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, 2019 and 2018, 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, 2019, we had $550.0 million variable-rate debt outstanding. The impact on interest expense of a 1% increase or decrease in the average interest rate would be approximately $5.5 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, 2019.

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, 2019 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 under Item 1A “Risk Factors”, included in our Quarterly Report on Form 10-Q filed with the SEC on May 2, 2019 and under Item 1A "Risk Factors", included in our Annual Report on Form 10-K filed with the SEC on February 21, 2019. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

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

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

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Program	Approximate Dollar Value of Shares that May Yet be Purchased under the Plans or Programs (in millions) (1)
July 1, 2019 - July 31, 2019	4,807,150	$ 4.42	4,807,150	$ —

(1) On April 1, 2019, we announced an extension of our ongoing repurchase program until December 31, 2019 and an increase of the program to authorize repurchases up to an incremental amount of $100.0 million in common stock from the date of the extension, bringing the total amount authorized to be repurchased to approximately $163.2 million. The July 2019 share repurchase completed the authorized Share Repurchase Program.

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	Master Assignment and Amendment No. 8 to Amended and Restated Credit Agreement, dated as of August 28, 2019, 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 August 30, 2019).
10.2	Separation and General Release Agreement, dated September 4, 2019, between Extraction Oil & Gas, Inc., XOG Services, LLC. and Russell T. Kelley, Jr. (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 September 4, 2019).
10.3†	Indemnification Agreement (Audrey Robertson) (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on September 19, 2019).
*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.

† Management contract or compensatory plan or agreement.

SIGNATURES

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

Date: November 7, 2019.

Extraction Oil & Gas, Inc.

By: /S/ MATTHEW R. OWENS

Matthew R. Owens

President and Acting Chief Executive Officer

(principal executive officer)

By: /S/ TOM L. BROCK.

Tom L. Brock

Vice President and Chief Accounting 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, Matthew R. Owens, 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 7, 2019

/S/ MATTHEW R. OWENS

Matthew R. Owens
President and Acting Chief Executive Officer
(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, Tom L. Brock, 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 7, 2019

/S/ TOM L. BROCK

Tom L. Brock
Vice President and Chief Accounting 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, 2019 of Extraction Oil & Gas, Inc. (the "Company"), as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Matthew R. Owens, President and Acting Chief Executive Officer 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 7, 2019

/S/ MATTHEW R. OWENS

Matthew R. Owens
President and Acting Chief Executive Officer
(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, 2019 of Extraction Oil & Gas, Inc. (the “Company”), as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Tom L. Brock, Vice President and Chief Accounting Officer 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 7, 2019

/S/ TOM L. BROCK

Tom L. Brock
Vice President and Chief Accounting Officer
(Principal Financial Officer)