

THE EXTRACTION OIL & GAS 2018 ANNUAL REPORT

A FOUNDATION OF STRENGTH



A LETTER TO OUR SHAREHOLDERS

Dear Fellow Shareholders:



Last year was another foundational year for us as we continued to build on our progress made since Extraction's inception. As an industry leader in the Denver-Julesburg Basin of Colorado, we have proven leadership and operating teams focused on creating long term shareholder value. Our people remain the core of who we are, and we have been recognized for the third consecutive year as one of Denver's "Top Workplaces." Our major triumphs and accomplishments in 2018 will serve as our foundation of strength as we prepare for the road ahead.

2018 was a year of many milestones for us.

Extraction was recognized by the State of Colorado with a Gold Award in its Environmental Leadership Program for consistently exceeding rules and regulations in one of the strictest-regulated operating environments in the nation. We built on our impeccable safety record which has now eclipsed 1.3 million man hours without a single recordable employee incident. Keeping the communities where we operate and our employees and contractors safe and secure is paramount. We also established the Extraction Foundation with a lasting and sustainable mission providing charitable contributions to the communities in which we work and our employees live including plans for elementary, secondary and post-secondary educational grants and scholarships, as well as community-enhancing joint venture projects.

Our growing production combined with our steady capital program culminated in free cash flow generation during the fourth quarter as previously planned dating back to our IPO in 2016. Robust growth within cash flow has become a cornerstone goal for us. Our ability to grow within cash flow demonstrates the high quality nature of our 179,000 net acre leasehold position located within the core of the DJ Basin targeting the oil-prone Codell and Niobrara formations. We grew our total net equivalent production by 47 percent year-on-year while establishing a new company record quarterly production rate of over 85 thousand barrels of oil equivalent per day. Our crude oil production grew 53% year-on-year while establishing a new quarterly record high production rate of 46,584 barrels per day. Proved reserves grew 11% year-on-year to 337 million barrels equivalent.

We also formed and funded Elevation Midstream, our midstream subsidiary that is currently building out oil, gas and water gathering systems in the southern portion of our acreage encompassing our Southwest Wattenberg and Hawkeye development areas, the first of which is scheduled to be in service in the third quarter of 2019.

As we focus on the road ahead, we are committed to growing our production within cash flow while continuing to improve our already low and efficient operating cost structure. With management and employee ownership of over six percent of our common stock and an industry-leading set of shareholder-friendly compensation incentives, we are very well-aligned with our public shareholders when it comes to creating long-lasting and sustainable shareholder value for many years to come.

Sincerely,



Mark Erickson

Chairman and CEO

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

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

For the fiscal year ended December 31, 2018

OR

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

For the transition period from _____ to _____

Commission file number 001-37907

EXTRACTION OIL & GAS, INC.

(Exact name of registrant as specified in its charter)

DELAWARE

46-1473923

(State or other jurisdiction of
incorporation or organization)

(IRS Employer
Identification No.)

**370 17th Street, Suite 5300
Denver, Colorado**

80202

(Address of principal executive offices)

(Zip Code)

(720) 557-8300

(Registrant's telephone number, including area code)

Title of each class

Name of exchange on which registered

Common Stock, par value \$0.01

NASDAQ Global Select Market

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act

Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes ☐ No ☒

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

Large accelerated filer ☒

Accelerated filer ☐

Non-accelerated filer ☐

Smaller reporting company ☐

Emerging growth company ☐

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of voting and non-voting common equity held by non-affiliates of the registrant was approximately \$0.9 billion as of June 30, 2018, (based on the last sale price of such stock as quoted on the NASDAQ Global Select Market).

The total number of shares of common stock, par value \$0.01 per share, outstanding as of February 19, 2019 was 171,554,356.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement for the 2019 Annual Meeting of Stockholders, to be filed no later than 120 days after the end of the fiscal year to which this Annual Report on Form 10-K relates, are incorporated by reference into Part III of this Annual Report on Form 10-K.

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

This Annual 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. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Review and consider the cautionary statements and disclosures, specifically those under Item 1A, *Risk Factors*, made in this report and our other filings with the Securities and Exchange Commission for further information on risk and uncertainties that could affect our business, financial condition, results of operations and cash flows. 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. 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.

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 Annual 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.

GLOSSARY OF OIL AND GAS TERMS

Unless indicated otherwise or the context otherwise requires, references in this report to the "Company," "Extraction," "us," "we," "our," or "ours" or like terms refer to Extraction Oil & Gas, Inc., following the completion of our initial public offering on October 17, 2016, as described under Note 9 — Equity in Item 8 in this Annual Report. When used in the historical context, the "Company," "Holdings," "us," "we," "our" and "ours" or like terms refer to Extraction Oil & Gas Holdings, LLC and its subsidiaries. Holdings is our accounting predecessor, for which we present the consolidated financial statements in this Annual Report.

The terms defined in this section are used throughout this Annual 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.

"Developed acreage" means the number of acres that are allocated or assignable to producing wells or wells capable of production.

"Development well" means a well drilled to a known producing formation in a previously discovered field, usually offsetting a producing well on the same or an adjacent oil and natural gas lease.

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

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

"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.

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

"NGL" means natural gas liquids.

"NYMEX" means New York Mercantile Exchange.

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

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

"Prospect" means a geological area which is believed to have the potential for oil and natural gas production.

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

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

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

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

"PV-10 value" means the present value of estimated future gross revenue to be generated from the production of estimated net proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date indicated (unless such prices or costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization, discounted using an annual discount rate of 10 percent. While this measure does not include the effect of income taxes as it would in the use of the standardized measure calculation, it does provide an indicative representation of the relative value of the Company on a comparative basis to other companies and from period to period.

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

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

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

"Reserve life" represents the estimated net proved reserves at a specified date divided by actual production for the preceding 12-month period.

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

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

"SEC" means the Securities and Exchange Commission.

"SEC pricing" means the price per Bbl for oil or per MMBtu for natural gas as calculated from the unweighted arithmetic average first-day-of-the-month prices for the prior 12 months.

"Seismic data" means an exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of a subsurface rock formation.

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

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

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

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

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

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

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

PART I

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

Company Overview

We are an independent oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves, as well as the construction and support of midstream assets to gather and process crude oil and gas production in the Rocky Mountain region, primarily in the Wattenberg Field of the Denver-Julesburg Basin (the “DJ Basin”) of Colorado. The Wattenberg Field has been producing since the 1970s and is a premier North American oil and natural gas basin characterized by high recoveries relative to drilling and completion costs, high initial production rates, long reserve life and multiple stacked producing horizons. We have assembled, as of December 31, 2018, approximately 179,300 net acres of large, contiguous acreage blocks in some of the most productive areas of the DJ Basin, indicated by the results of our horizontal drilling program and the results of offset operators, which we refer to as the “Core DJ Basin”. The 179,300 net acres includes our new acquisition area (the “Hawkeye Area”) in primarily Arapahoe and Adams Counties, which makes up approximately 68,700 of the 179,300 net acres. We believe our acreage in the Core DJ Basin has been significantly delineated by our own drilling success and by the success of offset operators, providing confidence that our inventory is relatively low-risk, repeatable and will continue to generate economic returns. We are primarily focused on growing our proved reserves and production primarily through the development of our large inventory of identified liquids-rich horizontal drilling locations in the DJ Basin.

We were founded in November 2012 with the objective of becoming a Wattenberg focused company with acreage that has (i) low development risk as a result of being within the vicinity of other successful wells drilled by other oil and gas companies, (ii) limited vertical well drainage relative to offset operators in a field with significant historical vertical activity, and (iii) higher oil content than was traditionally targeted when many operators first established their position in the field seeking natural gas production. We believe these characteristics enhance our horizontal production capabilities, recoveries and economic results. Our drilling economics are further enhanced by our ability to drill longer laterals due to our large contiguous acreage position, which our management team built through organic leasing and a series of strategic acquisitions. We operated 96% of our horizontal production for the year ended December 31, 2018 and maintain control of a large majority of our drilling inventory. In addition, we proactively seek to secure the necessary midstream and operational infrastructure to keep pace with our production growth.

For the year ended December 31, 2018, we have drilled 286 gross one-mile equivalent horizontal wells and have completed 268 gross one-mile equivalent horizontal wells. We are currently running a full time two-rig program and our 2019 capital budget anticipates a one to two operated drilling rig program. Our average net daily production during the fourth quarter and year ended December 31, 2018 was approximately 85,780 BOE/d and 76,019 BOE/d, respectively.

The following table provides summary information regarding our proved reserves as of December 31, 2018, and our average net daily production for the year ended December 31, 2018.

Estimated Total Proved Reserves ⁽¹⁾							Average Net Production	
Oil	Natural Gas	NGL	Total	%	%	%	(BOE/d)	R/P Ratio
(MBbls)	(MMcf)	(MBbls)	(MBoe)	Oil	Liquids ⁽²⁾	Developed	(1)(3)	(Years)(4)
135,846	703,268	94,851	347,908	39%	66%	40%	76,019	12.5

(1) Includes de minimis reserves and production attributable to properties in our Other Rockies Area. Please see “—Other Properties.”

(2) Includes both oil and NGL.

(3) Average net daily production. Consisted of approximately 53% oil, 28% natural gas and 19% NGL.

(4) Represents the number of years proved reserves would last assuming production continued at the average rate for the year ended December 31, 2018. Because production rates naturally decline over time, the R/P Ratio is not a useful estimate of how long properties should economically produce.

The following table presents information regarding our horizontal drilling locations on a one-mile equivalent basis as of December 31, 2018. We have not booked proved reserves on all of these drilling locations.

Identified Horizontal Niobrara and Codell Drilling Locations ⁽¹⁾⁽²⁾⁽³⁾	
	Total
Gross	6,436
Net	4,175

- (1) As adjusted for lateral length to present one-mile equivalents (approximately 4,200 feet). Please see “Business—Drilling Locations” for more information regarding the process and criteria through which these drilling locations were identified. The drilling locations on which we actually drill will depend on the availability of capital, regulatory approvals, takeaway capacity, commodity prices, costs, actual drilling results and other factors. Any drilling activities we are able to conduct on these identified locations may not be successful and may not result in the addition of proved reserves to our existing proved reserves base.
- (2) Does not include gross and net locations in the Other Rockies Area (as defined below).
- (3) Includes 128 drilled but uncompleted one-mile equivalent gross wells as of December 31, 2018.

Our Properties

Core DJ Basin

Our current operations are located in the DJ Basin, primarily in the Wattenberg Field where we target the oil and liquids-weighted Niobrara and Codell formations. As of December 31, 2018, our position in the Core DJ Basin consisted of approximately 179,300 net acres.

Our estimated proved reserves at December 31, 2018 were 347.9 MMBoe. As of December 31, 2018, we had a total of 1,538 gross wells capable of producing, of which 865 were horizontal wells. The vertical wells we operate primarily serve to hold leases until we can drill more efficient horizontal wells on acreage we lease. Therefore, production from vertical wells does not represent a material amount of our current production and is anticipated to decline as a percentage of total production in the future as we drill more horizontal wells. Our average net daily production during the year ended December 31, 2018 was approximately 76,019 BOE/d. Our working interest for all wells capable of producing averages approximately 74% and our net revenue interest is approximately 61%.

We continue to expand our proved reserves in this area by drilling non-proved horizontal locations. As of December 31, 2018, we had an identified drilling inventory of approximately 564 gross (364 net) proved undeveloped horizontal drilling locations with varying lateral lengths on our acreage with average gross well costs of \$5.2 million (\$2.8 million normalized to 4,200 foot lateral length). During 2018, we drilled 161 gross operated horizontal wells and completed 161 gross operated horizontal wells.

Other Properties

We hold approximately 138,100 net acres outside of the Core DJ Basin, which we refer to as our “Other Rockies Area,” that we believe is prospective for many of the same formations as our properties in the Core DJ Basin. As of December 31, 2018, there were de minimis proved reserves associated with this acreage. Average daily production associated with these properties for the year ended December 31, 2018 was approximately 347 BOE/d.

Gathering Systems and Facilities

Elevation Midstream, LLC (“Elevation”), a Delaware limited liability company and an unrestricted subsidiary of ours, is focused on the construction of gathering systems and facilities operations to serve the development of our acreage in Hawkeye and Southwest Wattenberg areas. Future revenues and operating expenses associated with the gathering systems and facilities operations will be primarily derived from intersegment transactions for services provided to our exploration, development and production operations.

2019 Capital Budget

Our 2019 capital budget for the drilling and completion of operated and non-operated wells is approximately \$585.0 million to \$675.0 million, substantially all of which we intend to allocate to the Core DJ Basin. We expect to drill 125 gross operated wells, complete 122 gross operated wells and turn-in-line 111 gross operated wells. Our capital budget 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.

Recent Developments

Proposition 112

On November 6, 2018, registered voters in the State of Colorado cast their ballots and rejected Proposition 112 ("Prop. 112"), with 55% of ballots cast against the measure. Prop. 112 would have created a rigid 2,500-foot setback from oil and gas facilities to the nearest occupied structure and other "vulnerable areas," which included parks, ball fields, open space, streams, lakes and intermittent streams. It would have dramatically increased the amount of surface area off-limits to new energy development by 26 times and put 94% of private land in the top five oil and gas producing counties in the State of Colorado off-limits to new development. Please see "Risk Factors-Changes in the legal and regulatory environment governing the oil and natural gas industry, particularly changes specific to the DJ Basin of Colorado, could have a material adverse effect on our business" for more information.

Recent Acquisitions and Divestitures

Proposed March 2019 Divestiture

In January 2019, we entered into a definitive agreement with an unaffiliated oil and gas company to sell approximately 5,000 net acres of leasehold and producing properties primarily in Weld County, Colorado (the "Proposed March 2019 Divestiture"). Upon closing, we will receive total consideration of approximately \$22.4 million in cash, subject to customary purchase price adjustments. The effective date for the Proposed March 2019 Divestiture is July 1, 2018 with purchase price adjustments calculated as of the closing date, which is scheduled for late March 2019. We continue to explore divestitures, as part of our ongoing initiative to divest of non-strategic assets.

December 2018 Divestitures

In December 2018, we completed various sales of our 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. The majority of these assets were from our Other Rockies Area.

August 2018 Divestiture

In August 2018, Elevation Midstream, LLC ("Elevation"), a Delaware limited liability company and subsidiary of the Company, received proceeds of \$83.6 million and recognized a gain of \$83.6 million for the 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. We had acquired our interest in March 2018 in exchange for the contribution of an acreage dedication, which was considered a nonfinancial asset.

April 2018 Divestitures

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

April 2018 Acquisition

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

January 2018 Acquisition

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

Amendments to Revolving Credit Facility and Capital Activity

January 2019 Credit Facility Amendment

On January 8, 2019, we amended our revolving credit facility to permit prepayments and redemptions of our unsecured bonds, subject to certain term, conditions and financial thresholds.

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 does not obligate us to acquire any specific nominal amount of Senior Notes. As of the date of this filing, we have repurchased 2026 Senior Notes with a nominal value of \$13.1 million for \$10.5 million in connection with the Senior Notes Repurchase Program.

December 2018 Credit Facility Amendment

On December 20, 2018, we amended our revolving credit facility to increase the borrowing base from \$800.0 million to \$1.2 billion, associated with the postponed November 1, 2018 scheduled borrowing base determination. The current elected commitments remained at \$650.0 million.

Stock Repurchase Program

On November 19, 2018, we announced that our Board of Directors had approved a stock repurchase program under which we are authorized to repurchase up to \$100.0 million of our outstanding common stock from time to time in the open market, through negotiated transactions or otherwise (the "Stock Repurchase Program"). The program is expected to be funded by a combination of internally generated cash flows and our existing liquidity, including cash on hand and short-term revolver borrowings. The Stock Repurchase Program will expire on March 31, 2019. During the year ended December 31, 2018, we repurchased approximately 4.1 million shares of our common stock for \$26.2 million.

October 2018 Credit Facility Amendment

On October 2, 2018, we amended our revolving credit facility to (i) postpone the November 1, 2018 scheduled borrowing base redetermination until December 15, 2018 and (ii) permit us to make payments with respect to our own equity, subject to certain terms, conditions and financial thresholds. See the *December 2018 Credit Facility Amendment* for the resulting borrowing base increase.

Elevation Securities Purchase Agreement

On July 3, 2018, Elevation entered into a securities purchase agreement (the "Securities Purchase Agreement") with a third party (the "Purchaser"), pursuant to which Elevation agreed to sell 150,000 Preferred Units (the "Elevation Preferred Units") of Elevation at a price of \$990 per Elevation Preferred Unit with an aggregate liquidation preference of \$150.0 million (the "Private Placement"), in a transaction exempt from the registration requirements under the Securities Act of 1933, as amended (the "Securities Act"). The Private Placement closed on July 3, 2018 (the "Preferred Unit Closing Date") and resulted in net proceeds of approximately \$141.9 million, \$25.4 million of which was a reimbursement to Extraction for previously

incurred midstream capital expenditures and general and administrative expenses. These Preferred Units are non-recourse to Extraction.

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

As part of the transaction, Extraction also committed to Elevation that it would drill at least 425 wells in the acreage dedicated to Elevation by December 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.

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, such dividend is payable in cash or in kind at the election of Elevation. After June 30, 2020, such dividend is payable solely in cash.

May 2018 Credit Facility Amendment

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

February 2018 Credit Facility Amendment

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

2026 Senior Notes

On January 25, 2018, we issued at par \$750.0 million principal amount of 5.625% Senior Notes due February 1, 2026 (the "2026 Senior Notes" and the offering, the "2026 Senior 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. We received net proceeds of approximately \$737.9 million after deducting discounts and fees. We used \$534.2 million of the net proceeds from the 2026 Senior Notes Offering to tender for our 2021 Senior Notes, \$52.7 million to redeem any 2021 Senior Notes not tendered and the remainder was used for general corporate purposes. Our borrowing base under our revolving credit facility was automatically reduced to \$700.0 million in connection with the closing of the 2026 Senior Notes Offering; however, there was no change to the current maximum lending commitments of \$650.0 million.

Tender Offer to Purchase 2021 Senior Notes

On January 25, 2018, we announced the results of our cash tender offer to purchase any and all of the outstanding aggregate principal amount of the 2021 Senior Notes. An aggregate principal amount of \$500.6 million (91%) was tendered and paid, in addition to a make-whole premium of \$32.6 million and accrued and unpaid interest of \$1.0 million, on January 25, 2018. On February 17, 2018, we redeemed 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.

On January 5, 2018, we amended the revolving credit facility to (i) increase the borrowing base from \$525.0 million to \$750.0 million, subject to the current maximum lending commitments of \$650.0 million, (ii) increase the maximum amount for the letter of credit issued in favor of a purchaser of our crude oil be increased from \$25.0 million to \$35.0 million, and (iii) amend certain provisions of the credit agreement, including the commitments and allocations of each lender. Subsequent to this amendment our borrowing base was reduced in connection with the 2026 Senior Notes Offering and increased to \$1.2 billion, subject to the current maximum lending commitments of \$650.0 million, in connection with the December 2018 Credit Facility Amendment. See “—Liquidity and Capital Resources—Revolving Credit Facility.”

Drilling Locations

As of December 31, 2018, we have identified a total of 6,436 gross identified drilling locations as adjusted to one-mile equivalents. Our target horizontal location count implies lateral lengths of 4,200 feet per well. Approximately 16% of our gross identified drilling locations are attributable to proved undeveloped reserves. Our identified drilling locations have been identified based on our review of structure as well as production data from offsetting wells. We have internally evaluated this production data based on an extensive geological and engineering database. Information incorporated into this process includes both our own proprietary information as well as publicly available industry data. Specifically, open hole logging data, production statistics from operated and non-operated wells, and petrophysical data from cores taken from wellbores have provided the technical basis from which we identified the potential locations. These data points have allowed us to determine areas for each reservoir that may produce commercial quantities of hydrocarbons and the viability of the potential locations.

Oil, Natural Gas and NGL Data

Proved Reserves

Evaluation and Review of Proved Reserves

Our historical proved reserves estimates as of December 31, 2018, 2017 and 2016 were prepared based on reports by Ryder Scott Company, L.P. (“Ryder Scott”), our independent petroleum engineers. Within Ryder Scott, the technical person primarily responsible for preparing the estimates set forth in the Ryder Scott summary reserve reports incorporated herein for the year ended December 31, 2018 was Stephen Gardner. Mr. Gardner has been practicing consulting petroleum engineering at Ryder Scott since 2006. Mr. Gardner is a registered Professional Engineer in the State of Colorado and Texas and has over 13 years of practical experience in the estimation and evaluation of reserves. Mr. Gardner graduated from the Brigham Young University with a Bachelor of Science Degree in Mechanical Engineering. As technical principal, Mr. Gardner meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and is proficient in applying industry standard practices to engineering evaluations as well as applying SEC and other industry reserves definitions and guidelines. Ryder Scott does not own an interest in any of our properties, nor is it employed by us on a contingent basis. Ryder Scott’s report is attached as Exhibit 99.1 to this Annual Report on Form 10-K.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our assets in the DJ Basin. Our internal technical team members meet with our independent reserve engineers periodically during the period covered by the proved reserve report to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to the independent reserve engineers for our properties, such as ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs. These reserve estimates are reviewed and approved by our Lead Reserves and Performance Engineer with final approval by Senior Vice President of Operations.

Our Senior Vice President of Operations oversees our corporate strategic planning, reservoir, reserves, operations, environmental and regulatory affairs. He is the technical person primarily responsible for overseeing the preparation of our reserves estimates and third-party report of our reserves estimates. He holds a Bachelor of Science in environmental engineering and a Master of Science in petroleum engineering with over 24 years of industry experience and significant DJ Basin technical and operational expertise. The Senior Vice President of Operations reports directly to our President.

Our policies and processes regarding internal controls over the recording of reserves estimates require reserves to be in compliance with the SEC definitions and guidance and prepared in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Our internal controls over

reserves estimates also include the review and verification of historical production data, which are based on actual production data as reported by us; preparation of reserve estimates and verification of property ownership by our land department. Additionally, 100% of our total net proved reserves are evaluated by Ryder Scott, on an annual basis.

Estimation of Proved Reserves

Under SEC rules, proved reserves are those quantities of oil, natural gas and NGL, 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. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a “high degree of confidence that the quantities will be recovered.” All of our proved reserves as of December 31, 2018, 2017 and 2016 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil, natural gas and NGL and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil, natural gas and NGL reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into four broad categories or methods: (1) production performance-based methods; (2) material balance-based methods; (3) volumetric-based methods; and (4) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy. Non-producing reserve estimates, for developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for our properties, due to the mature nature of the properties targeted for development and an abundance of subsurface control data.

To estimate economically recoverable proved reserves and related future net cash flows, Ryder Scott considered many factors and assumptions, including the use of reservoir parameters derived from geological and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates.

Under SEC rules, reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves have been demonstrated to yield results with consistency and repeatability, and include production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, historical well cost and operating expense data.

Summary of Oil, Natural Gas and NGL Reserves.

The following table presents our estimated net proved oil, natural gas and NGL reserves as of December 31, 2018, 2017 and 2016.

	As of December 31,		
	2018	2017	2016
Proved Developed Producing Reserves:			
Oil (MBbls)	43,477	34,350	13,345
Natural gas (MMcf)	292,598	208,311	93,233
NGL (MBbls)	36,361	26,368	11,453
Total (MBoe) ₍₁₎	128,604	95,437	40,337
Proved Developed Non-Producing Reserves:			
Oil (MBbls)	3,598	2,728	3,813
Natural gas (MMcf)	23,901	13,925	14,685
NGL (MBbls)	3,328	1,564	1,901
Total (MBoe) ₍₁₎	10,910	6,613	8,162
Proved Undeveloped Reserves:			
Oil (MBbls)	88,771	74,197	73,837
Natural gas (MMcf)	386,769	403,933	399,817
NGL (MBbls)	55,162	49,174	49,094
Total (MBoe) ₍₁₎	208,395	190,693	189,567
Total Proved Reserves:			
Oil (MBbls)	135,846	111,275	90,995
Natural gas (MMcf)	703,268	626,169	507,735
NGL (MBbls)	94,851	77,106	62,448
Total (MBoe) ₍₁₎	347,908	292,743	238,066

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

Reserve engineering is and must be recognized as a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. Please read "Risk Factors" appearing elsewhere in this Annual Report.

Additional information regarding our proved reserves can be found in the notes to our financial statements included elsewhere in this Annual Report.

Proved Undeveloped Reserves ("PUDs")

Annually, management develops a five-year capital expenditure plan based on our best available data at the time the plan is developed. Our capital expenditure plan incorporates a development plan for converting PUD reserves to proved developed. The development plan includes only PUD reserves that we are reasonably certain will be drilled within five years of booking based upon management's evaluation of a number of qualitative and quantitative factors, including estimated risk-based returns; estimated well density; commodity prices and cost forecasts; recent drilling recompletion or re-stimulation results and well performance; anticipated availability of services, equipment, supplies and personnel; and seasonal weather. This process is intended to ensure that PUD reserves are only booked for locations where a final investment decision has been

made. Our five year development plan generally does not contemplate a uniform (i.e. 20% per year) conversion of our PUD reserves.

Management reviews and revises the development plan throughout the year and may modify the development plan after evaluating a number of factors, including operating and drilling results; current and expected future commodity prices; estimated risk-based returns; estimated well density; advances in technology; cost and availability of services, equipment, supplies and personnel; acquisition and divestiture activity; and our current and projected financial condition and liquidity. If there are changes that result in certain PUD reserves no longer being scheduled for development within five years from the date of initial booking, we reclass those PUD reserves to non-proved reserve categories. In addition, PUD locations and reserves may be removed from the development plan ahead of their five-year life expiration as a result of changes in our development plan related to factors enumerated above.

As of December 31, 2018, our proved undeveloped reserves were composed of 88,771 MBbls of oil, 386,769 MMcf of natural gas and 55,162 MBbls of NGL, for a total of 208,395 MBoe. PUDs will be converted from undeveloped to developed as the necessary and required capital has been invested and the wells are capable of producing.

The following table summarizes our changes in PUDs during the years ended December 31, 2018, 2017 and 2016:

	MBoe
Balance, December 31, 2015	128,505
Conversion into proved developed reserves	(15,923)
Extensions and discoveries	50,882
Acquisitions	31,081
Changes in well performance, timing and other	(4,978)
Balance, December 31, 2016	189,567
Conversion into proved developed reserves	(43,798)
Extensions and discoveries	37,573
Acquisitions	12,720
Changes in well performance, timing and other	(5,369)
Balance, December 31, 2017	190,693
Conversion into proved developed reserves	(39,498)
Extensions and discoveries	64,955
Acquisitions	12,325
Changes in well performance, timing and other	(20,080)
Balance, December 31, 2018	<u>208,395</u>

Extensions and discoveries of 64,955 MBoe, 37,573 MBoe and 50,882 MBoe during the years ended December 31, 2018, 2017 and 2016, respectively, resulted primarily from new proved undeveloped locations added as a result of the drilling and completion of new wells. Downward revisions of previous estimates of 20,080 MBoe during the year ended December 31, 2018 resulted primarily from the revisions resulting from changes in timing due to midstream curtailment issues. We intend to develop these reserves outside the five year PUD window. Downward revisions of previous estimates of 5,369 MBoe, 4,978 MBoe during the years ended December 31, 2017 and 2016, respectively, resulted primarily from the revisions resulting from price changes and revisions resulting from production and performance.

Estimated future development costs relating to the development of PUDs at December 31, 2018 were projected to be approximately \$396.7 million for the year ending December 31, 2019, \$388.0 million in 2020, \$398.9 million in 2021, \$399.5 million in 2022 and \$321.9 million in 2023. Costs incurred relating to the development of PUDs were \$392.3 million, \$442.5 million and \$161.4 million during the years ended December 31, 2018, 2017 and 2016, respectively. As we continue to develop our properties and have more well production and completion data, we believe we will continue to realize cost savings and experience lower relative drilling and completion costs as we convert PUDs into proved developed reserves in upcoming years. All of our PUD drilling locations are scheduled to be drilled within five years of their initial booking. We converted 39,498 MBoe, 43,798 MBoe and 15,923 MBoe to proved developed producing reserves in the years ended December 31, 2018, 2017 and 2016, respectively. During the year ended December 31, 2018, we converted 113 PUD locations to proved developed producing reserves, which represent 21% of our PUD reserve volumes and 16% of our PUD locations as of December 31, 2017.

Productive Wells

As of December 31, 2018, we owned an average 74% working interest in 1,538 gross (1,139 net) productive wells. As of December 31, 2017, we owned an average 71% working interest in 1,300 gross (916 net) productive wells. As of December 31, 2016, we owned an average 73% working interest in 1,014 gross (738 net) productive wells. Productive wells consist of producing wells and wells capable of production, including oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

The following table sets forth information relating to the productive wells in which we owned a working interest as of December 31, 2018:

	Productive Wells	
	Gross	Net
Oil wells	1,359	992
Natural gas wells	179	147
Total wells	1,538	1,139

Developed and Undeveloped Acreage

The following tables set forth information as of December 31, 2018 relating to our leasehold acreage. Developed acreage is acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease. Undeveloped acreage is acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and/or natural gas, regardless of whether such acreage contains proved reserves.

The following table sets forth our gross and net acres of developed and undeveloped oil and gas leases as of December 31, 2018:

Area	Developed Acreage ⁽¹⁾		Undeveloped Acreage ⁽²⁾		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Core DJ Basin	119,400	96,100	163,300	83,200	282,700	179,300
Other Rockies	61,600	42,900	152,600	95,200	214,200	138,100

(1) Developed acreage is acres spaced or assigned to productive wells.

(2) Undeveloped acreage are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. We intend to extend all of our material leases to the extent possible and expect to incur a maximum of \$54.6 million to extend every material lease that is set to expire in the next three years, without taking into account the drilling of PUDs and holding leases by production and therefore we do not expect a material reduction in our proved undeveloped reserves as a result of lease expirations. The following table sets forth the undeveloped acreage, as of December 31, 2018, that will expire in the years indicated below unless production is established within the spacing units covering the acreage or the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates.

Area	2019		2020		2021		2022+	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Core DJ Basin	16,400	13,900	32,900	22,800	23,100	18,900	9,600	7,100
Other Rockies	12,700	6,300	31,800	19,300	17,600	11,900	30,200	17,700

Drilling Results

The following table sets forth information with respect to the number of wells completed by us during the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

	For the Year Ended December 31,					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Development Wells⁽¹⁾:						
Productive ⁽²⁾	160.0	136.4	196.0	157.8	72.0	54.9
Dry	—	—	—	—	—	—
Exploratory Wells⁽¹⁾:						
Productive ⁽²⁾	1.0	1.0	2.0	1.1	—	—
Dry	—	—	—	—	—	—
Total Wells⁽¹⁾:						
Productive ⁽²⁾	161.0	137.4	198.0	158.9	72.0	54.9
Dry	—	—	—	—	—	—

(1) Includes only wells completed by us.

(2) Although a well may be classified as productive upon completion, future changes in oil, natural gas and NGL prices, operating costs and production may result in the well becoming uneconomical, particularly exploratory wells where there is no production history.

As of December 31, 2018, we had 128.0 gross wells (97.4 net) wells waiting on commencement of completion activities.

Operations

General

We operated 96% of our horizontal production for the year ended December 31, 2018. As operator, we design and manage the development of a well and supervise operation and maintenance activities on a day-to-day basis. Independent contractors engaged by us provide all the equipment and personnel associated with these activities. We employ petroleum engineers, geologists and land professionals who work to improve production rates, increase reserves and lower the cost of operating our oil and natural gas properties.

Marketing and Customers

We sell the majority of the production from properties we operate for both our account and the account of the other working interest owners in these properties. We sell our production to purchasers at market prices. Our largest purchaser is an oil marketer who has the ability to sell production into multiple markets.

During the year ended December 31, 2018, approximately 87% of our production was sold to two customers. However, we do not believe that the loss of a single purchaser, including these two, would materially affect our business because there are numerous other potential purchasers in the area in which we sell our production. For the year ended December 31, 2018, Mercuria Energy Trading, Inc. and DCP Midstream, LP represented 76% and 11% of our total oil and gas revenues, respectively. For the year ended December 31, 2017, Mercuria Energy Trading, Inc., DCP Midstream, LP and Kerr McGee, LLC represented 65%, 19% and 11% of our total oil and gas revenues, respectively. For the year ended December 31, 2016, Mercuria Energy Trading, Inc., NGL Crude Logistics, LLC, DCP Midstream, LP and United Energy Trading, LLC represented 25%, 23%, 19% and 16% of our total oil and gas revenues, respectively.

Future revenues and operating expenses associated with the gathering systems and facilities operations will be primarily derived from intersegment transactions for services provided to our exploration, development and production operations by Elevation Midstream, LLC., an unrestricted subsidiary to the Company. As of December 31, 2018, these gathering systems and facilities operations are not in service, therefore, there are no such revenues for the year ended December 31, 2018.

Transportation and Gathering

During the initial development of our fields, we consider all gathering and delivery infrastructure in the areas of our production. Our oil is collected from the wellhead to our tank batteries and then transported by the purchaser by truck or pipeline to a tank farm, another pipeline or a refinery. Our natural gas is transported from the wellhead to the purchaser's meter and pipeline interconnection point.

We are subject to long-term delivery commitments for the transportation and gathering of our production. Our oil marketer is 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, we amended this agreement with our oil marketer that requires us to sell all of our crude oil from an area of mutual interest in exchange for a make-whole provision that allows us to satisfy any minimum volume commitment deficiencies incurred by our oil marketer with future barrels of crude oil in excess of their minimum volume commitment through October 31, 2018. In December 2017, we extended the term of this agreement through October 31, 2019 and posted a letter of credit in the amount of \$35.0 million. We are currently in the process of amending and extending this agreement. We evaluate our contracts for loss contingencies and accrues for such losses, if the loss can be reasonably estimated and deemed probable. We also have two long-term crude oil gathering commitments with an unconsolidated subsidiary, in which we have a minority ownership interest. The first agreement commenced in November 2016 and has a term of ten years with a minimum volume commitment of an average 9,167 Bbl/d in year one, 17,967 Bbl/d in year two, 18,800 Bbl/d for years three through five and 10,000 Bbl/d for years six through ten. The second agreement will commence in or around July 2019 and has a term of ten years for an average of 3,200 Bbl/d in year one, 8,000 Bbl/d in year two, 14,000 Bbl/d in year three, 16,000 Bbl/d in years four through eight, 12,000 Bbl/d in year nine and 10,000 Bbl/d in year ten. The remaining aggregate amount of estimated payments under these agreements is approximately \$875.8 million.

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

In February 2019, we entered into two long-term gas gathering agreements with third-party midstream providers. The first agreement will commence in or around November 2019 and has a term of twenty years with a minimum volume commitment of 251 Bcf to be delivered within the first seven years. The annual commitments over seven years are to be delivered on an average 48,000 Mcf/d in year one, 96,000 Mcf/d in year two, 132,000 Mcf/d in year three, 120,000 Mcf/d in year four, 108,000 Mcf/d in year five, 104,000 Mcf/d in year six and 80,000 Mcf/d in year seven. The aggregate amount of estimated payments under this agreement is approximately \$317.7 million. The second agreement 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 our current drilling plans, we expect to meet these volume commitments.

We estimate that midstream constraints negatively impacted our production by approximately 18.5 MBOE/d, or 24%, during the year ended December 31, 2018. We are currently working with various midstream providers to address processing constraints in the DJ Basin.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources than we do. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil, natural gas and NGL market prices. Our larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the governments of the United States and the jurisdictions in which we operate. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position.

Title to Properties

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties in connection with acquisition of leasehold acreage. At such time as we determine to conduct drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects prior to commencement of drilling operations. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry.

Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion, obtain an updated title review or opinion or review previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect our carrying value of the properties.

We believe that we have satisfactory title to all of our material assets. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or materially interfere with our use of these properties in the operation of our business. In addition, we believe that we have obtained or have the ability to obtain sufficient rights-of-way grants and permits from public authorities and private parties for us to operate our business in all material respects as described in this Annual Report.

Seasonality of Business

Weather conditions affect the demand for, and prices of, oil, natural gas and NGL. Demand for oil, natural gas and NGL is typically higher in the fourth and first quarters resulting in higher prices. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

Oil and Gas Leases

The typical oil and gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and gas produced from any wells drilled on the leased premises. Our interest in our properties after lessor royalties and other leasehold burdens is generally 80%. Our working interest for all producing wells averages approximately 74% and our net revenue interest is approximately 61%.

Regulation of the Oil and Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Historically, our compliance costs have not had a material adverse effect on our results of operations; however, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission (the “FERC”) and the courts. We cannot predict when or whether any such proposals may become effective. We do not believe that we would be affected by any such action materially differently than similarly situated competitors.

Regulation Affecting Production

The production of oil and natural gas is subject to United States federal and state laws and regulations, and orders of regulatory bodies under those laws and regulations, governing a wide variety of matters. All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil or natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratable or fair apportionment of production from fields and individual wells. These laws and regulations may limit the amount of oil and gas we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGL within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but there can be no assurance that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and gas that may be produced from our wells, negatively affect the economics of production from these wells or limit the number of locations we can drill.

The failure to comply with the rules and regulations of oil and natural gas production and related operations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Regulation Affecting Sales and Transportation of Commodities

Sales prices of gas, oil, condensate and NGL are not currently regulated and are made at market prices. Although prices of these energy commodities are currently unregulated, the United States Congress historically has been active in their regulation. We cannot predict whether new legislation to regulate oil and gas, or the prices charged for these commodities might be proposed, what proposals, if any, might actually be enacted by the United States Congress or the various state legislatures and what effect, if any, the proposals might have on our operations. Sales of oil and natural gas may be subject to certain state and federal reporting requirements.

The price and terms of service of transportation of the commodities, including access to pipeline transportation capacity, are subject to extensive federal and state regulation. Such regulation may affect the marketing of oil and natural gas produced by us, as well as the revenues received for sales of such production. Gathering systems may be subject to state ratable take and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, oil and natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase, or accept for gathering, without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes may affect whether and to what extent gathering capacity is available for oil and natural gas production, if any, of the drilling program and the cost of such capacity. Further state laws and regulations govern rates and terms of access to intrastate pipeline systems, which may similarly affect market access and cost.

The FERC regulates interstate natural gas pipeline transportation rates and service conditions. The FERC is continually proposing and implementing new rules and regulations affecting interstate transportation. The stated purpose of many of these regulatory changes is to ensure terms and conditions of interstate transportation service are not unduly discriminatory or unduly preferential, to promote competition among the various sectors of the natural gas industry and to promote market transparency. We do not believe that our drilling program will be affected by any such FERC action in a manner materially differently than other similarly situated natural gas producers.

In addition to the regulation of natural gas pipeline transportation, FERC has jurisdiction over the purchase or sale of gas and the purchase or sale of transportation services subject to FERC's jurisdiction pursuant to the Energy Policy Act of 2005 ("EPAAct 2005"). Under the EPAAct 2005, it is unlawful for "any entity," including producers such as us, that are otherwise not subject to FERC's jurisdiction under the Natural Gas Act of 1938 ("NGA"), to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of gas or the purchase or sale of transportation services subject to regulation by FERC, in contravention of rules prescribed by FERC. FERC's rules implementing this provision make it unlawful, in connection with the purchase or sale of gas subject to the jurisdiction of FERC or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAAct 2005 also gives FERC authority to impose civil penalties up to approximately \$1.2 million per day per violation for violations of the NGA and the Natural Gas Policy Act of 1978 ("NGPA"). The anti-manipulation rule applies to activities of otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which includes the annual reporting requirements under FERC Order No. 704 (defined below).

In December 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing ("Order No. 704"). Under Order No. 704, certain market participants, including a producer that engages in certain wholesale sales or purchases of gas that equal or exceed 2.2 million MMBtus of physical natural gas in the previous calendar year, must annually report such sales and purchases to FERC on Form No. 552 on May 1 of each year. Form No. 552 contains aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. Not all types of natural gas sales are required to be reported on Form No. 552. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704. Order No. 704 is intended to increase the transparency of the wholesale gas markets and to assist FERC in monitoring those markets and in detecting market manipulation.

The FERC also regulates rates and terms and conditions of service on interstate transportation of liquids, including oil and NGL, under the Interstate Commerce Act, as it existed on October 1, 1977 ("ICA"). Prices received from the sale of liquids may be affected by the cost of transporting those products to market. The ICA requires that certain interstate liquids pipelines maintain a tariff on file with FERC. The tariff sets forth the established rates as well as the rules and regulations governing the service. The ICA requires, among other things, that rates and terms and conditions of service on interstate common carrier pipelines be "just and reasonable." Such pipelines must also provide jurisdictional service in a manner that is not unduly discriminatory or unduly preferential. Shippers have the power to challenge new and existing rates and terms and conditions of service before FERC.

The rates charged by many interstate liquids pipelines are currently adjusted pursuant to an annual indexing methodology established and regulated by FERC, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by FERC. For the five-year period beginning July 1, 2016, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 1.23%. This adjustment is subject to review every five years. Under FERC's regulations, a liquids pipeline can request a rate increase that exceeds the rate obtained through application of the indexing methodology by obtaining market-based rate authority (demonstrating the pipeline lacks market power), establishing rates by settlement with all existing shippers, or through a cost-of-service approach (if the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology). Increases in liquids transportation rates may result in lower revenue and cash flows for us.

In addition, due to common carrier regulatory obligations of liquids pipelines, capacity must be prorated among shippers in an equitable manner in the event there are nominations in excess of capacity or for new shippers. Therefore, new shippers or increased volume by existing shippers may reduce the capacity available to us. Any prolonged interruption in the operation or curtailment of available capacity of the pipelines that we rely upon for liquids transportation could have a material adverse effect on our business, financial condition, results of operations and cash flows. However, we believe that access to

liquids pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Rates for intrastate pipeline transportation of liquids are subject to regulation by state regulatory commissions. The basis for intrastate liquids pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate liquids pipeline rates, varies from state to state. We believe that the regulation of liquids pipeline transportation rates will not affect our operations in any way that is materially different from the effects on our similarly situated competitors.

In addition to FERC's regulations, we are required to observe anti-market manipulation laws with regard to our physical sales of energy commodities. In November 2009, the Federal Trade Commission ("FTC") issued regulations pursuant to the Energy Independence and Security Act of 2007, intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to approximately \$1.1 million per violation per day. In July 2010, Congress passed the Dodd-Frank Act, which incorporated an expansion of the authority of the Commodity Futures Trading Commission ("CFTC") to prohibit market manipulation in the markets regulated by the CFTC. This authority, with respect to oil swaps and futures contracts, is similar to the anti-manipulation authority granted to the FTC with respect to oil purchases and sales. In July 2011, the CFTC issued final rules to implement their new anti-manipulation authority. The rules subject violators to a civil penalty of up to the greater of approximately \$1.1 million or triple the monetary gain to the person for each violation.

Regulation of Environmental and Safety and Health Matters

Our operations are subject to numerous stringent and complex federal, state and local laws and regulations governing safety and health aspects of our operations, the release, disposal, or discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental entities, including the U.S. Environmental Protection Agency ("EPA"), the U.S. Occupational Safety and Health Administration ("OSHA") and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. These laws and regulations may, among other things (i) require the acquisition of permits to conduct drilling and other regulated activities; (ii) restrict the types, quantities and concentration of various materials that may be released into the environment or injected into formations in connection with oil and natural gas drilling and production activities; (iii) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (iv) require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; (v) apply specific health and safety criteria addressing worker protection; and (vi) impose substantial liabilities for pollution resulting from drilling and production operations. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, including the assessment of monetary fines or penalties, the imposition of investigatory, remedial or corrective obligations, the occurrence of delays or restrictions in permitting or performance of projects, and the issuance of orders enjoining performance of some or all of our operations in a particular area.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly well drilling, construction, completion or water management activities, or waste handling, storage transport, disposal, or remediation requirements could have a material adverse effect on our financial position and results of operations. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental spills or releases may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such spills or releases, including any third-party claims for damage to property, natural resources or persons. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business and operating results.

On January 14, 2019, in *Martinez v. Colorado Oil and Gas Conservation Commission*, the Colorado Supreme Court overturned ruling by the Colorado Court of Appeals that held that the Colorado Oil & Gas Conservation Commission ("COGCC") had incorrectly concluded that it lacked statutory authority to undertake a proposed rulemaking "to suspend the issuance of permits that allow hydraulic fracturing until it can be done without adversely impacting human health and safety and without impairing Colorado's atmospheric resource and climate system, water, soil, wildlife, other biological resources." The Colorado Court of Appeals concluded that Colorado's Oil and Gas Conservation Act mandated that oil and gas development "be regulated subject to the protection of public health, safety, and welfare, including protection of the environment and wildlife resources." The Colorado Supreme Court held that the COGCC properly denied the petition requesting the proposed rulemaking, finding that the agency is required under the Oil and Gas Conservation Act to "foster the

development of oil and gas resources, protecting and enforcing the rights of owners and producers," and that, while the COGCC must also prevent and mitigate significant adverse environmental impacts to the extent necessary to protect public health, safety, and welfare, it does so "only after taking into consideration cost-effectiveness and technical feasibility."

The following is a summary of the more significant existing and proposed environmental and safety and health laws, as amended from time to time, to which our business operations are or may be subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous Substances and Wastes

The Resource Conservation and Recovery Act ("RCRA"), and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the guidance issued by the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. In the course of our operations, we generate some amounts of ordinary industrial wastes that may be regulated as hazardous wastes. We are required to manage the disposal of hazardous and non-hazardous wastes in compliance with RCRA and analogous state laws. RCRA currently exempts many exploration and production wastes from classification as hazardous waste. Specifically, RCRA excludes from the definition of hazardous waste produced waters and other wastes intrinsically associated with the exploration, development, or production of crude oil and natural gas. However, these oil and gas exploration and production wastes may still be regulated under state solid waste laws and regulations, and it is possible that certain oil and natural gas exploration and production wastes currently classified as non-hazardous could be classified as hazardous waste in the future. For example, in December 2016, several environmental groups and the EPA entered into a consent decree to address EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and natural gas wastes from regulation as hazardous wastes under RCRA. Under this consent decree, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and natural gas wastes or sign a determination that revision of the regulations is not necessary. If EPA proposes a rulemaking for revised oil and natural gas regulations, the consent decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. Stricter regulation of wastes generated during our or our customer's operations could result in an increase in our and our customer's, as well as the oil and natural gas exploration and production industry's, costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the Superfund law, and comparable state laws impose joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the current and former owners and operators of the site where the release occurred and anyone who disposed or arranged for the transport or disposal of a hazardous substance released at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA and any state analogs may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. In addition, it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances.

We currently own, lease, or operate, and in the past have owned, leased or operated, numerous properties that have been used for oil and natural gas exploration, production and processing and other operations for many years. Hazardous substances, wastes, or petroleum hydrocarbons may have been released on, under or from the properties owned, leased or operated by us, or on, under or from other locations where such substances have been taken for treatment or disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of substances, including hazardous substances, wastes, or petroleum hydrocarbons, was not under our control. These properties and the hazardous substances, wastes or petroleum hydrocarbons disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial operations to prevent future contamination, the costs of which could have a material adverse effect on our business and results of operations.

Water Discharges

The Federal Water Pollution Control Act, also known as the Clean Water Act ("CWA"), and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other

hazardous substances, into state waters and waters of the United States. The discharge of pollutants into regulated waters, including jurisdictional wetlands, is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of navigable waters by a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The CWA also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. In June 2015, the EPA and the U.S. Army Corps of Engineers ("Corps") published a final rule to revise the definition of "waters of the United States" ("WOTUS") for all CWA programs, but legal challenges to this rule followed and the rule was stayed nationwide by the U.S. Sixth Circuit Court of Appeals in October 2015. In response to this decision, the EPA and the Corps resumed nationwide use of the agencies' prior regulations defining the term "waters of the United States." However, in January 2018, the U.S. Supreme Court ruled that the rule revising the WOTUS definition must first be reviewed in the federal district courts, which resulted in a withdrawal of the stay by the Sixth Circuit. In addition, the EPA has proposed to repeal the rule revising the WOTUS definition and, in January 2018, issued a final rule to delay its implementation until 2020 to allow time for EPA to reconsider the definition of the term "waters of the United States." Subsequent litigation in the federal district courts has resulted in patchwork application of the rule in some states (e.g. California, Oklahoma), but not others (e.g. Colorado). In December 2018, EPA and the Corps issued a proposed rule revising the WOTUS definition that would provide discrete categories of jurisdictional waters and tests for determining whether a particular water body meets any of those classifications. Several groups have already announced their intentions to challenge the proposed rule. To the extent this rule is enforced in jurisdictions in which we operate or a revised rule expands the scope of the CWA's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas in connection with any expansion activities. Federal and state regulatory agencies may impose substantial administrative, civil and criminal penalties as well as other enforcement mechanisms for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations, including spills and other non-authorized discharges.

The Oil Pollution Act of 1990 ("OPA"), amends the CWA and sets minimum standards for prevention, containment and cleanup of oil spills. The OPA applies to vessels, offshore facilities, and onshore facilities, including exploration and production facilities that may affect waters of the United States. Under OPA, responsible parties, including owners and operators of onshore facilities, may be held strictly liable for oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. The OPA also requires owners or operators of certain onshore facilities to prepare Facility Response Plans for responding to a worst-case discharge of oil into waters of the United States.

Subsurface Injections

In the course of our operations, we produce water in addition to oil and natural gas. Water that is not recycled may be disposed of in disposal wells, which inject the produced water into non-producing subsurface formations. Underground injection operations are regulated pursuant to the Underground Injection Control ("UIC") program established under the Safe Drinking Water Act ("SDWA") and analogous state laws. The UIC program requires permits from the EPA or an analogous state agency for the construction and operation of disposal wells, establishes minimum standards for disposal well operations, and restricts the types and quantities of fluids that may be disposed. A change in UIC disposal well regulations or the inability to obtain permits for new disposal wells in the future may affect our ability to dispose of produced water and ultimately increase the cost of our operations. For example, in response to recent seismic events near belowground disposal wells used for the injection of oil and natural gas-related wastewaters, regulators in some states, including Colorado, have imposed more stringent permitting and operating requirements for produced water disposal wells. In Colorado, permit applications are reviewed specifically to evaluate seismic activity and, as of 2011, the state has required operators to identify potential faults near proposed wells, if earthquakes historically occurred in the area, and to accept maximum injection pressures and volumes based on fracture gradient as conditions to permit approval. Additionally, legal disputes may arise based on allegations that disposal well operations have caused damage to neighboring properties or otherwise violated state or federal rules regulating waste disposal. These developments could result in additional regulation, restriction on the use of injection wells by us or by commercial disposal well vendors whom we may use from time to time to dispose of wastewater, and increased costs of compliance, which could have a material adverse effect on our capital expenditures and operating costs, financial condition, and results of operations.

Air Emissions

The Clean Air Act (the "CAA") and comparable state laws restrict the emission of air pollutants from many sources, such as, for example, tank batteries and compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance standards. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase

air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to delay the development of oil and natural gas projects. Over the next several years, we may be charged royalties on natural gas losses or required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in October 2015, the EPA issued a final rule under the CAA, lowering the National Ambient Air Quality Standard (“NAAQS”) for ground-level ozone from 75 parts per billion (“ppb”) for the 8-hour primary and secondary ozone standards to 70 ppb for both standards. In 2018, EPA finalized the initial area designations for the 2015 ozone standard. Certain areas, such as Denver Metro North Front Range, were designated as Marginal non-attainment. The Denver Metro North Front Range area is currently under significant threat of being redesignated as a serious non-attainment area for ozone due to high levels detected in 2016 and 2017. Colorado is seeking an extension to the attainment date and EPA has proposed to retroactively approve the requested extension by one year, to July 20, 2019. It is not likely that another one-year extension will be granted and the Denver Metro North Front Range area may be reclassified to serious non-attainment for 2020. Reclassification of areas or imposition of more stringent standards (including a lowering of the major source threshold for volatile organic compounds and oxides of nitrogen and the resulting increased likelihood that a source may be subject to Non-Attainment New Source Review) may make it more difficult to construct new or modified sources of air pollution in newly designated non-attainment areas. Also, states are expected to implement more stringent requirements as a result of this new final rule, which could apply to our operations. In addition, during the fall of 2016, EPA issued final Control Techniques Guidelines (“CTGs”) for reducing volatile organic compound emissions from existing oil and natural gas equipment and processes in ozone non-attainment areas, including the Denver Metro North Front Range Ozone 8-hour Non-Attainment area. In 2017, as part of the federal CTG process for oil and natural gas, Colorado undertook a stakeholder and rulemaking effort to compare the CTGs to existing Colorado requirements to ensure they meet applicable federal requirements, which resulted in revisions to Colorado's Regulation Number 7. The new state regulations include more stringent air quality control requirements applicable to our operations. In another example, in June 2016, the EPA finalized a revised rule regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent permitting requirements. Compliance with these or other air pollution control and permitting requirements have the potential to delay the development of oil and natural gas projects and increase our costs of development and production, which costs could have a material adverse impact on our business and results of operations.

Regulation of Greenhouse Gas (“GHG”) Emissions

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHG. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. At the federal level, no comprehensive climate change legislation has been implemented to date. However, the EPA has adopted rules under authority of the CAA that, among other things, establish Potential for Significant Deterioration (“PSD”) construction and Title V operations permit reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal pollutant emissions, which reviews could require meeting “best available control technology” standards for those emissions. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, including, among other things, onshore producing facilities, which include certain of our operations.

Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and natural gas operations. In June 2016, the EPA published the New Source Performance Standards (“NSPS”) Subpart OOOOa standards that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. However, in September 2018, under the new administration, EPA proposed amendments that would relax the requirements of the Subpart OOOOa standards. Similarly, in September 2018, the federal Bureau of Land Management (“BLM”) issued a rule that relaxes or rescinds certain requirements of its November 2016 rule enacted to reduce methane emissions by regulating venting, flaring, and leaks from oil and gas operations on federal and American Indian lands. California and New Mexico have challenged the rule in ongoing litigation. In addition, in April 2018, a coalition of states filed a lawsuit aiming to force EPA to establish guidelines for limiting methane emissions from existing sources in the oil and natural gas section; that lawsuit is currently pending.

On the international level, in December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France that prepared an agreement requiring member countries to review and “represent a progression” in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. This “Paris Agreement” was signed by the United States in April 2016 and entered into force in November 2016; however, this agreement does not create any

binding obligations for nations to limit their GHG emissions, but rather includes pledges to voluntarily limit or reduce future emissions. In follow-up to an earlier announcement by President Trump, in August 2017, the U.S. Department of State officially informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time.

The adoption and implementation of any international, federal or state legislation or regulations that require reporting of GHG or otherwise limit emissions of GHG from our equipment and operations could result in increased costs to reduce emissions of GHG associated with our operations as well as delays or restrictions in our ability to permit GHG emissions from new or modified sources. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil, natural gas and NGL we produce and lower the value of our reserves, which devaluation could be significant. One or more of these developments could have a materially adverse effect on our business, financial condition and results of operations. Additionally, it should be noted that increasing concentrations of GHG in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations. At this time, we have not developed a comprehensive plan to address the legal, economic, social or physical impacts of climate change on our operations. Finally, notwithstanding potential risks related to climate change, the International Energy Agency, an autonomous intergovernmental organization involved in international energy policy, estimates that global energy demand will continue to rise and will not peak until after 2040 and oil and gas will continue to represent a substantial percentage of global energy use over that time. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector.

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and oil from dense subsurface rock formations. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemical additives under pressure into targeted geological formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing is typically regulated by state oil and natural gas commissions or similar state agencies. However, several federal agencies have conducted investigations or asserted regulatory authority over certain aspects of the process. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances. Additionally, the EPA published in June 2016 an effluent limitations guideline final rule pursuant to its authority under the SDWA prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants; asserted regulatory authority in 2014 under the SDWA over hydraulic fracturing activities involving the use of diesel and issued guidance covering such activities; and issued in 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the BLM published a final rule in March 2015 establishing new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands including well casing and wastewater storage requirements and an obligation for exploration and production operators to disclose what chemicals they are using in fracturing activities. Following years of litigation, the BLM rescinded the rule in December 2017; however, that rescission has been challenged by several environmental groups and states in ongoing litigation. Also, from time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In the event that a new, federal level of legal restrictions relating to the hydraulic fracturing process is adopted in areas where we operate, we may incur additional costs to comply with such federal requirements that may be significant in nature, and also could become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development, or production activities.

At the state level, Colorado, where we conduct operations, is among the states that has adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure or well-construction requirements on hydraulic fracturing operations. For example, significant new oil and gas-related legislation is expected to be introduced in Colorado in February or March 2019, and while there is uncertainty regarding the specific contents of and prospects for the anticipated legislation, the political climate in the state suggests that there is a strong appetite for substantial and swiftly enacted new laws that provide for greater restrictions on oil and natural gas development within the state. Moreover, states could elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York in 2015. Also, certain interest groups in Colorado opposed to oil and natural gas development generally, and hydraulic fracturing in particular, have from time to time advanced various options for ballot initiatives that, if approved, would allow revisions to the state constitution in a manner that would make such exploration and production activities in the state

more difficult in the future. However, during the November 2016 voting process, one proposed amendment placed on the Colorado state ballot making it relatively more difficult to place an initiative on the state ballot was passed by the voters. As a result, there are more stringent procedures now in place for placing an initiative on a state ballot. In addition to state laws, local land use restrictions may restrict drilling or the hydraulic fracturing process and cities may adopt local ordinances allowing hydraulic fracturing activities within their jurisdictions but regulating the time, place and manner of those activities. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, including, for example, on federal and American Indian lands, we could incur potentially significant added cost to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling wells.

In the event that local or state restrictions or prohibitions are adopted in areas where we conduct operations, including the DJ Basin in Colorado, that impose more stringent limitations on the production and development of oil and natural gas, including, among other things, the development of increased setback distances, we and similarly situated oil and natural exploration and production operators in the state may incur significant costs to comply with such requirements or may experience delays or curtailment in the pursuit of exploration, development, or production activities, and possibly be limited or precluded in the drilling of wells or in the amounts that we and similarly situated operators are ultimately able to produce from our reserves. Any such increased costs, delays, cessations, restrictions or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, including, for example, on federal and American Indian lands, we could incur potentially significant added cost to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling wells.

Moreover, because most of our operations are conducted in a particular area, the DJ Basin in Colorado, legal restrictions imposed in that area will have a significantly greater adverse effect than if we had our operations spread out amongst several diverse geographic areas. Consequently, in the event that local or state restrictions or prohibitions are adopted in the DJ Basin in Colorado that impose more stringent limitations on the production and development of oil and natural gas, we may incur significant costs to comply with such requirements or may experience delays or curtailment in the pursuit of exploration, development, or production activities, and possibly be limited or precluded in the drilling of wells or in the amounts that we are ultimately able to produce from our reserves. Any such increased costs, delays, cessations, restrictions or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

Activities on Federal Lands

Oil and natural gas exploration, development and production activities on federal lands, including American Indian lands and lands administered by the BLM, are subject to the National Environmental Policy Act (“NEPA”). NEPA requires federal agencies, including the BLM, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. While we currently have minimal exploration, development and production activities on federal lands, our proposed exploration, development and production activities are expected to include leasing of federal mineral interests, which will require the acquisition of governmental permits or authorizations that are subject to the requirements of NEPA. This process has the potential to delay or limit, or increase the cost of, the development of oil and natural gas projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects. Moreover, depending on the mitigation strategies recommended in Environmental Assessments or Environmental Impact Statements, we could incur added costs, which may be substantial.

Endangered Species and Migratory Birds Considerations

The federal Endangered Species Act (“ESA”), and comparable state laws were established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species or that species’ habitat. Similar protections are offered to migrating birds under the Migratory Bird Treaty Act. We may conduct operations on oil and natural gas leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species that potentially could be listed as threatened or endangered under the ESA may exist. Moreover, as a result of one or more agreements entered into by the U.S. Fish and Wildlife Service, the agency is required to make a determination on listing of numerous species as endangered or threatened under the ESA pursuant to specific timelines. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from

species protection measures, time delays or limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

Employee Safety and Health

We are subject to the requirements of the Occupational Safety and Health Act and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, OSHA's hazard communication standard, the Emergency Planning and Community Right-To-Know Act and comparable state statutes and any implementing regulations require that we maintain and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens. For example, under a new OSHA standard limiting respirable silica exposure, the oil and gas industry must implement engineering controls and work practices to limit exposures below the new limits by June 2021. Failure to comply with OSHA requirements can lead to the imposition of penalties.

Related Permits and Authorizations

Many environmental laws require us to obtain permits or other authorizations from state and/or federal agencies before initiating certain drilling, construction, production, operation, or other oil and natural gas activities, and to maintain these permits and compliance with their requirements for on-going operations. These permits are generally subject to protest, appeal, or litigation, which can in certain cases delay or halt projects and cease production or operation of wells, pipelines, and other operations.

Related Insurance

We maintain insurance against some risks associated with above or underground contamination that may occur as a result of our exploration and production activities. However, this insurance is limited to activities at the well site and there can be no assurance that this insurance will continue to be commercially available or that this insurance will be available at premium levels that justify its purchase by us. The occurrence of a significant event that is not fully insured or indemnified against could have a materially adverse effect on our financial condition and operations. Further, we have no coverage for gradual, long-term pollution events.

Employees

As of December 31, 2018, we employed 279 people. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory.

From time to time we utilize the services of independent contractors to perform various field and other services.

Facilities

Our corporate headquarters is located in Denver, Colorado.

Available Information

Our common stock is listed and traded on the NASDAQ under the symbol "XOG." Our reports, proxy statements and other information filed with the SEC can be inspected and copied at the offices of the NASDAQ, at One Liberty Plaza, 165 Broadway, New York, New York 10006.

We also make available free of charge through our website, www.extractionog.com, electronic copies of certain documents that we file with the SEC, including our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

ITEM 1A. RISK FACTORS

RISK FACTORS

There are many factors that may affect our business and results of operations. If any of the following risks actually occur, our business, financial condition and results of operations could be materially and adversely affected and we may not be able to achieve our goals. We cannot assure you that any of the events discussed in the risk factors below will not occur. Further, the risks and uncertainties described below are not the only ones we face. Additional risks not presently known to us or that we currently deem immaterial may also materially affect our business.

Risks Related to the Oil, Natural Gas and NGL Industry and Our Business

Oil and natural gas prices are volatile. An extended or further decline in commodity prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The prices we receive for our oil, natural gas and NGL production heavily influence our revenue, profitability, access to capital and future rate of growth. Oil, natural gas and NGL are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the commodities market has been volatile. For example, during the period from January 1, 2014 to December 31, 2018, NYMEX West Texas Intermediate oil prices ranged from a high of \$107.26 per Bbl to a low of \$26.21 per Bbl. Average daily prices for NYMEX Henry Hub gas ranged from a high of \$6.15 per MMBtu to a low of \$1.64 per MMBtu during the same period. The duration and magnitude of the recent decline in oil prices cannot be predicted. This market will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil, natural gas and NGL;
- the price and quantity of foreign imports;
- political conditions in or affecting other producing countries, including conflicts in the Middle East, Africa, South America and Russia;
- the level of global exploration and production;
- the level of global inventories;
- prevailing prices on local price indices in the areas in which we operate;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- localized and global supply and demand fundamentals and transportation availability;
- members of the Organization of Petroleum Exporting Countries and other oil exporting nations to agree to and maintain oil price and production controls;
- weather conditions;
- technological advances affecting energy consumption;
- the effect of worldwide energy conservation and environmental protection efforts;
- the price and availability of alternative fuels;
- domestic, local and foreign governmental regulation and taxes; and
- shareholder activism and activities by non-governmental organizations to restrict the exploration, development and production of oil and natural gas.

Since November 2014, prices for U.S. oil have weakened in response to continued high levels of production, a buildup in inventories and lower global demand. Prices for oil have showed some recovery beginning in late 2016 and continuing into 2018, but remain significantly below 2014 levels.

Lower commodity prices will reduce our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in the present value of our reserves and our ability to develop future reserves. Lower commodity prices may also reduce the amount of oil, natural gas and NGL that we can produce

economically and may impact our ability to satisfy our obligations under firm-commitment transportation agreements. 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 may be limited, and we are not under an obligation to hedge a specific portion of our oil or natural gas production.

Using lower prices in estimating proved reserves would likely result in a reduction in proved reserve volumes due to economic limits. While it is difficult to project future economic conditions and whether such conditions will result in impairment of proved property costs, we consider several variables including specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors. In addition, sustained periods with oil and natural gas prices at levels lower than current West Texas Intermediate strip prices and the resultant effect such prices may have on our drilling economics and our ability to raise capital may require us to re-evaluate and postpone or eliminate our development drilling, which could result in the reduction of some of our proved undeveloped reserves and related standardized measure. If we are required to curtail our drilling program, we may be unable to continue to hold leases that are scheduled to expire, which may further reduce our reserves. As a result, a substantial or extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.

We have acquired significant amounts of unproved property in order to further our development efforts and expect to continue to undertake acquisitions in the future. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and increase our results of operations over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our investments. Additionally, we cannot assure you that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

Properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties that we acquire or obtain protection from sellers against such liabilities.

Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential liabilities, including environmental liabilities. Such assessments are inexact and inherently uncertain. For these reasons, the properties we have acquired or will acquire in the future may not produce as projected. In connection with the assessments, we perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not review every well, pipeline or associated facility. We cannot necessarily observe structural and environmental problems, such as pipe corrosion or groundwater contamination, when a review is performed. We may be unable to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

Our exploration and development projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the exploitation, development and acquisition of oil and natural gas reserves. We expect to fund our 2019 capital expenditures with borrowings under our revolving credit facility and possibly through asset sales or additional capital markets transactions. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, oil, natural gas and NGL prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. A reduction in commodity prices from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to grow production. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources.”

Substantially all of our producing properties are located in the DJ Basin of Colorado, making us vulnerable to risks associated with operating in one major geographic area. Specifically, as the DJ Basin is an area of high industry activity, we may be unable to hire, train or retain qualified personnel needed to manage and operate our assets.

Substantially all of our producing properties are geographically concentrated in the DJ Basin of Colorado, an area in which industry activity has increased rapidly. At December 31, 2018, substantially all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors or other regional events, delays or interruptions of production from wells in this area caused by governmental regulation, including at the state and local level, processing or transportation capacity constraints, market limitations, water shortages or other drought or extreme weather related conditions or interruption of the processing or transportation of oil, natural gas or NGL. For example, bottlenecks in processing and transportation that have occurred in some recent periods in the Wattenberg Field have negatively affected our results of operations. Similarly, the concentration of our producing assets within a small number of producing formations exposes us to risks, such as changes in field-wide rules that could adversely affect development activities or production relating to those formations. In addition, in areas where exploration and production activities are increasing, as has been the case in recent years in the Wattenberg Field, the demand for, and cost of, drilling rigs, equipment, supplies, personnel, and oilfield services increase. Shortages or the high cost of drilling rigs, equipment, supplies, personnel, or oilfield services could delay or adversely affect our development and exploration operations or cause us to incur significant expenditures that are not provided for in our capital forecast, which could have a material adverse effect on our business, financial condition, or results of operations.

Specifically, demand for qualified personnel in this area, and the cost to attract and retain such personnel, has increased over the past few years and may increase substantially in the future. Moreover, our competitors, including those operating in multiple basins, may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. Any delay or inability to secure the personnel necessary for us to continue or complete our current and planned development activities could have a negative effect on production volumes or significantly increase costs, which could have a material adverse effect on our results of operations, liquidity and financial condition.

Changes in the legal and regulatory environment governing the oil and natural gas industry, particularly changes specific to the DJ Basin of Colorado, could have a material adverse effect on our business

Our business is subject to various forms of government regulation. Some local governments are adopting new requirements and restrictions on hydraulic fracturing and other oil and natural gas operations. Some local governments in Colorado, for instance, have amended their land use regulations to impose new requirements on oil and gas development, while other local governments have entered memoranda of agreement with oil and gas producers to accomplish the same objective. Beyond that, during the past few years, a total of five Colorado cities have passed voter initiatives temporarily or permanently prohibiting hydraulic fracturing. Since that time, local district courts have struck down the ordinances for certain of those Colorado cities, and such decisions were upheld by the Colorado Supreme Court in May 2016. Nevertheless, there is a continued risk that cities will adopt local ordinances that seek to regulate the time, place, and manner of hydraulic fracturing activities and oil and natural gas operations within their respective jurisdictions.

In addition, in 2014, 2016 and 2018, opponents of hydraulic fracturing sought statewide ballot initiatives that would have restricted oil and gas development in Colorado. The 2014 initiatives were withdrawn in return for the creation of a task force to craft recommendations for minimizing land use conflicts over the location of oil and natural gas facilities, and none of the 2016 initiatives were successful. However, in 2018, the Colorado Secretary of State approved a citizen-initiated ballot measure, referred to as Prop. 112, for inclusion on the statewide voter ballot in November 2018. Prop. 112 sought to amend the Colorado Revised Statutes to increase setback distances by requiring that all new oil and gas development on non-federal lands (i.e. state and private lands) be located at least 2,500 feet away from certain occupied structures, including homes, schools and hospitals, as well as certain defined "vulnerable areas," including playgrounds, permanent sports fields, public parks and open spaces, public drinking water sources, reservoirs, lakes, rivers, perennial and intermittent streams, and creeks. In contrast, rules adopted and enforced by the COGCC currently require that wells and production facilities be located at least 500 feet away from homes and 1,000 feet away from certain defined high occupancy building units, including schools, subject to certain exceptions. The term "oil and gas development" was broadly defined under Prop. 112 to include oil and gas exploration, drilling, hydraulic fracturing, flowlines, production and processing activities, including the development and production activities central to our operations. Under Prop. 112, state and local governments would have been allowed to designate vulnerable areas beyond those that are defined in the measure, but the proposal provided no additional guidance on procedures or any limitations with respect to such designations. Prop. 112 further provided that the state or a local government may increase the setback to a distance larger than 2,500 feet, again without any defined procedure, limitations, or governing standards. The COGCC conducted a study in 2018 and determined that, if Prop. 112 had been approved by state voters, an estimated 54% of Colorado's total land surface would be unavailable for new oil and gas development, or 85% of all non-

federal lands. Focusing on Weld County, located in the DJ Basin, the 2018 COGCC study determined that approval and adoption of Prop. 112 would have precluded new oil and gas development on approximately 78% of the total land surface and 85% of the non-federal land surface in the county. If Prop. 112 were to have passed and become law in the State of Colorado, we would have likely encountered updates to our long-term forecast which could have negatively impacted future operating cash flows, credit facility re-determinations, minimum volume commitments and lead to potential non-cash impairments.

Although Prop. 112 was ultimately unsuccessful, similar efforts are likely to continue in the future, which, if successful, could result in dramatically reducing the area available for future oil and gas development in Colorado or outright banning oil and gas development in Colorado. We cannot predict the nature or outcome of future ballot initiatives or other similar efforts. If we are required to cease operating in any of the areas in which we now operate as the result of bans or moratoria on drilling or related oilfield services activities, it could have a material effect on our business, financial condition, and results of operations.

Additionally, we are subject to laws and regulations concerning the location, spacing and permitting of the oil and natural gas wells we drill, among other matters. In particular, our business utilizes a methodology available in Colorado known as “forced pooling,” which refers to the ability of a holder of an oil and natural gas interest in a particular prospective drilling spacing unit to apply to the Colorado Oil & Gas Conservation Commission (“COGCC”) for an order forcing all other holders of oil and natural gas interests in such area into a common pool for purposes of developing that drilling spacing unit. This methodology is especially important for our operations in the Greeley area, where there are many interest holders. Changes in the legal and regulatory environment governing our industry, particularly any changes to Colorado forced pooling procedures that make forced pooling more difficult to accomplish, could result in increased compliance costs and adversely affect our business, financial condition and results of operations.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of hydrocarbons we are able to produce from existing wells;
- the prices at which our production is sold;
- the availability of takeaway capacity;
- our ability to acquire, locate and produce new reserves; and
- our ability to borrow under our revolving credit facility.

If our revenues or the borrowing base under our revolving credit facility decreases as a result of lower oil, natural gas and NGL prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations and growth at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flow generated by our operations or available borrowings under our revolving credit facility are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties, which in turn could lead to a decline in our reserves and production, and would adversely affect our business, financial condition and results of operations.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our exploitation, development and acquisition activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil and natural gas production.

Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see “—Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.” In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- delays imposed by or resulting from compliance with environmental and other regulatory requirements including limitations on or resulting from wastewater discharge and disposal, subsurface injections, GHG emissions and hydraulic fracturing;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or in obtaining water for hydraulic fracturing activities;
- lack of available capacity on interconnecting transmission pipelines;
- equipment failures or accidents, such as fires or blowouts;
- lack of available gathering facilities or delays in construction of gathering facilities;
- adverse weather conditions, such as blizzards, tornados and ice storms;
- issues related to compliance with environmental and other governmental regulations;
- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- declines in oil, natural gas and NGL prices;
- limited availability of financing at acceptable terms;
- title problems or legal disputes regarding leasehold rights; and
- limitations in the market for oil, natural gas and NGL.

Our identified drilling locations are scheduled over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill such locations.

Our management team has specifically identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil, natural gas and NGL prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the numerous potential well locations we have identified will ever be drilled or if we will be able to produce natural gas or oil from these or any other potential locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained or if existing producing wells that are holding leases with other potential locations cease to continue to produce in commercial quantities, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these potential locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations.

A substantial portion of our reserves are located in urban areas, which could increase our costs of development and delay production.

A substantial portion of our reserves are located in urban portions of the DJ Basin, which could disproportionately expose us to operational and regulatory risk in that area. Much of our operations are within the city limits of various municipalities in northeastern Colorado. In such urban and other populated areas, we may incur additional expenses, including expenses relating to mitigation of noise, odor and light that may be emitted in our operations, expenses related to the appearance of our facilities and limitations regarding when and how we can operate. The process of obtaining permits for drilling or for gathering lines to move our production to market in such areas may be more time consuming and costly than in more rural areas. In addition, we may experience a higher rate of litigation or increased insurance and other costs related to our operations or facilities in such highly populated areas.

Our drilling and production programs may not be able to obtain access on commercially reasonable terms or otherwise to truck transportation, pipelines, gas gathering, transmission, storage and processing facilities to market our oil and gas production, and our initiatives to expand our access to midstream and operational infrastructure may be unsuccessful.

The marketing of oil and natural gas production depends in large part on the capacity and availability of trucks, pipelines and storage facilities, gas gathering systems and other transportation, processing and refining facilities. Access to such facilities is, in many respects, beyond our control. If there is insufficient capacity available on these systems, or if these facilities are unavailable to us on commercially reasonable terms or otherwise, we could be forced to shut in some production or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons. We rely (and expect to rely in the future) on facilities developed and owned by third parties in order to store, process, transmit and sell our oil and gas production. Our plans to develop and sell our oil and gas reserves could be materially and adversely affected by the inability or unwillingness of third parties to provide sufficient facilities and services to us on commercially reasonable terms or otherwise, especially in areas of planned expansion where such facilities do not currently exist. The amount of oil and gas that can be produced is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, damage to the gathering, transportation, refining or processing facilities, or lack of capacity on such facilities. For example, recent increases in activity in the DJ Basin have contributed to bottlenecks in processing and transportation that have negatively affected our results of operations, and these adverse effects may be disproportionately severe to us compared to our more geographically diverse competitors. Additionally, we continued to experience constraints on the capacity available in certain pipelines that we use to transport natural gas and have been forced to shut in some production from time to time. Capacity constraints typically reduce the productivity of some of our older vertical wells and may on occasion limit incremental production from some of our newer horizontal wells. This constrains our production and reduces our revenue from the affected wells. Capacity constraints affecting natural gas production also impact the associated NGL. We are also dependent on the availability and capacity of oil purchasers for our production. Increases in the amount of oil that we transport out of the DJ Basin for sale would result in an increase in our transportation costs and would reduce the price we receive for the affected production.

Similarly, the concentration of our assets within a small number of producing formations exposes us to risks, such as changes in field-wide rules, which could adversely affect development activities or production relating to those formations. In addition, in areas where exploration and production activities are increasing, as has been the case in recent years in the DJ Basin, we are subject to increasing competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages or delays. The curtailments arising from these and similar circumstances may last from a few days to several months, and in many cases, we may be provided only limited, if any, notice as to when these circumstances will arise and their duration.

While we have undertaken initiatives to expand our access to midstream and operational infrastructure, these initiatives may be delayed or unsuccessful. As a result, our business, financial condition and results of operations could be adversely affected.

Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.

Our debt arrangements contain a number of significant covenants, including restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make certain acquisitions and investments;
- enter into mergers, consolidations or other transactions resulting in the transfer of all or substantially all of our assets;
- make certain payments, including paying dividends or distributions in respect of our equity;
- hedge future production or interest rates;
- redeem and prepay other debt;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

In addition, our debt arrangements require us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. These restrictions may also limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under our debt arrangements will impose on us.

Our revolving credit facility limits the amount we can borrow up to the lower of our aggregate lender commitments and a borrowing base amount, which the lenders, in their sole discretion, will determine on a semi-annual basis based upon projected revenues from the oil and natural gas properties securing our loan. The lenders will be able to unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our revolving credit facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. If the requisite number of lenders does not agree to a proposed borrowing base, then the borrowing base will be the highest borrowing base acceptable to such lenders. We will be required to repay outstanding borrowings in excess of the borrowing base. Our borrowing base is \$1.2 billion, subject to the current maximum lending commitments of \$650.0 million.

A breach of any covenant in our revolving credit facility will result in a default under the revolving credit facility after any applicable grace periods. A default, if not waived, could result in acceleration of the indebtedness outstanding under the facility and a default with respect to, and an acceleration of, the indebtedness outstanding under other debt agreements. The accelerated indebtedness would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to us. In addition, our obligations under our revolving credit facility are secured by perfected first priority liens and security interests on substantially all of our assets, including mortgage liens on oil and natural gas properties having at least 90% of the reserve value as determined by reserve reports, and if we are unable to repay our indebtedness under the revolving credit facility, the lenders could seek to foreclose on our assets.

We may be subject to risks in connection with divestitures

In 2018, we completed divestitures of several of our non-strategic assets and we have additional divestitures pending, as discussed in Item. "Business-Recent Developments." In addition, in 2019 we announced our ongoing initiative to divest of non-strategic assets in order to increase capital resources available for other core assets, create organizational and operational efficiencies or for other purposes. Various factors could materially affect our ability to dispose of such assets, including the approvals of governmental agencies or third parties and the availability of purchases willing to acquire the assets with terms we deem acceptable. Though we continue to evaluate various options for the divestiture of such assets, there can be no assurance that this evaluation will result in any specific action.

Sellers often retain certain liabilities or agree to indemnify buyers for certain matters related to the sold assets. The magnitude of any such retained liability or of the indemnification obligation is difficult to quantify at the time of the transaction and ultimately could be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a divestiture, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under our debt arrangements, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including our revolving credit facility and our Senior Notes, depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. If oil and natural gas prices remain at their current level for an extended period of time or decline, we may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

If our cash flows and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance indebtedness. Our ability to restructure or refinance indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. The terms of existing or future debt arrangements may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on outstanding indebtedness on a timely basis could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or

operations to meet debt service and other obligations. Our revolving credit facility and the indentures governing our 2024 Notes and 2026 Notes currently restrict our ability to dispose of assets and our use of the proceeds from such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet scheduled debt service obligations.

In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these potential locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations.

Our derivative activities could result in financial losses or could reduce our earnings.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of oil, natural gas and NGL, we enter into commodity derivative contracts for a significant portion of our production, primarily consisting of swaps, put options and call options. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Overview—Sources of Our Revenues.” Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contractual obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- there are issues with regard to legal enforceability of such instruments.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced, which could limit our ability to make future capital expenditures and make payments on our indebtedness, and which could also limit the size of our borrowing base. Future collateral requirements will depend on arrangements with our counterparties, highly volatile oil, natural gas and NGL prices and interest rates. In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for oil, natural gas and NGL, which could also have an adverse effect on our financial condition.

Our commodity derivative contracts expose us to risk of financial loss if a counterparty fails to perform under a contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty’s liquidity, which could make them unable to perform under the terms of the contract and we may not be able to realize the benefit of the contract. We are unable to predict sudden changes in a counterparty’s creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions.

During periods of declining commodity prices, our derivative contract receivable positions generally increase, which increases our counterparty credit exposure. While we utilize multiple counterparties, if the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss with respect to our commodity derivative contracts.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves.

In order to prepare reserve estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil, natural gas and NGL prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil, natural gas and NGL prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may revise reserve estimates to reflect production history, results of exploration and development, existing commodity prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated reserves. We generally base the estimated discounted future net cash flows from reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. For example, our estimated proved reserves as of December 31, 2018 were calculated under SEC rules using the unweighted arithmetic average first-day-of-the-month prices for the prior 12 months of \$65.56/Bbl for oil and \$3.10/MMBtu for natural gas, which for certain periods of 2018 were substantially above the available spot oil and natural gas prices. Using lower prices in estimating proved reserves would likely result in a reduction in proved reserve volumes due to economic limits.

There is a limited amount of production data from horizontal wells completed in the DJ Basin. As a result, reserve estimates associated with horizontal wells in this area are subject to greater uncertainty than estimates associated with reserves attributable to vertical wells in the same area.

Reserve engineers rely in part on the production history of nearby wells in establishing reserve estimates for a particular well or field. Horizontal drilling in the DJ Basin is a relatively recent development, whereas vertical drilling has been utilized by producers in this area for over 50 years. As a result, the amount of production data from horizontal wells available to reserve engineers is relatively small compared to that of production data from vertical wells. Until a greater number of horizontal wells have been completed in the DJ Basin, and a longer production history from these wells has been established, there may be a greater variance in our proved reserves on a year-over-year basis due to the transition from vertical to horizontal reserves in both the proved developed and proved undeveloped categories. We cannot assure you that any such variance would not be material and any such variance could have a material and adverse impact on our cash flows and results of operations. If our horizontal wells do not allow for the extraction of oil and natural gas in a manner or to the extent that we anticipate, we may not realize an acceptable return on our investments in such projects.

Part of our strategy involves drilling using the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve utilizing the latest drilling and completion techniques as developed by us and our service providers. During the year ended December 31, 2018, we have drilled 286 gross one-mile equivalent horizontal wells and have completed 268 gross one-mile equivalent horizontal wells, and therefore are subject to increased risks associated with horizontal drilling as compared to companies that have greater experience in horizontal drilling activities. Risks that we face while drilling include, but are not limited to, failing to land our wellbore in the desired drilling zone, not staying in the desired drilling zone while drilling horizontally through the formation, not running our casing the entire length of the wellbore and not being able to run tools and other equipment consistently through the horizontal wellbore. Risks that we face while completing our wells include, but are not limited to, not being able to fracture stimulate the planned number of stages, not being able to run tools the entire length of the wellbore during completion operations and not successfully cleaning out the wellbore after completion of the final fracture stimulation stage. In addition, our horizontal drilling activities may adversely affect our ability to successfully drill in one or more of our identified vertical drilling locations. Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and/or commodity prices decline, the return on our investment in these areas may not be as attractive as we anticipate. Further, as a result of any of these developments we could incur material write-downs of our oil and natural gas properties and the value of our undeveloped acreage could decline in the future.

Approximately 56% of our net leasehold acreage is undeveloped, and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases as well as have a material adverse effect on our oil and natural gas reserves and future production and, therefore, our future cash flow and income.

As of December 31, 2018, approximately 56% of our net leasehold acreage was undeveloped, or 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 proved reserves. Unless production is established on the undeveloped acreage covered by our leases, such leases will expire. Our future oil and natural gas reserves and production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage.

We are required to pay fees to our service providers based on minimum volumes under long-term contracts regardless of actual volume throughput.

We may enter into firm transportation, gas processing, gathering and compression service, water handling and treatment, or other agreements that require minimum volume delivery commitments. Our oil marketer is 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, we amended this agreement with our oil marketer that requires us to sell all of our crude oil from an area of mutual interest in exchange for a make-whole provision that allows us to satisfy any minimum volume commitment deficiencies incurred by our oil marketer with future barrels of crude oil in excess of their minimum volume commitment through October 31, 2018. In December 2017, we extended the term of this agreement through October 31, 2019 and posted a letter of credit in the amount of \$35.0 million. We are currently in the process of amending and extending this agreement. We evaluate our contracts for loss contingencies and accrues for such losses, if the loss can be reasonably estimated and deemed probable. We also have two long-term crude oil gathering commitments with an unconsolidated subsidiary, in which we have a minority ownership interest. The first agreement commenced in November 2016 and has a term of ten years with a minimum volume commitment of an average 9,167 Bbl/d in year one, 17,967 Bbl/d in year two, 18,800 Bbl/d for years three through five and 10,000 Bbl/d for years six through ten. The second agreement will commence in or around July 2019 and has a term of ten years for an average of 3,200 Bbl/d in year one, 8,000 Bbl/d in year two, 14,000 Bbl/d in year three, 16,000 Bbl/d in years four through eight, 12,000 Bbl/d in year nine and 10,000 Bbl/d in year ten. The remaining aggregate amount of estimated payments under these agreements is approximately \$875.8 million. If we have insufficient production to meet the minimum volumes under this agreement or any other firm commitment agreement we may enter into, our cash flow from operations will be reduced, which may require us to reduce or delay our planned investments and capital expenditures or seek alternative means of financing, all of which may have a material adverse effect on our results or operations.

The prices we receive for our production may be affected by local and regional factors.

The prices we receive for our production will be determined to a significant extent by factors affecting the local and regional supply of and demand for oil and natural gas, including the adequacy of the pipeline and processing infrastructure in the region to process, and transport, our production and that of other producers. Those factors result in basis differentials between the published indices generally used to establish the price received for regional oil and natural gas production and the actual price we receive for our production, which may be lower than index prices. If the price differentials pursuant to which our production is subject were to widen due to oversupply or other factors, our revenue could be negatively impacted.

Extreme weather conditions could adversely affect our ability to conduct drilling activities in the areas where we operate.

Our exploration, exploitation and development activities and equipment could be adversely affected by extreme weather conditions, such as winter storms, which may cause a loss of production from temporary cessation of activity or lost or damaged facilities and equipment. Such extreme weather conditions could also impact other areas of our operations, including access to our drilling and production facilities for routine operations, maintenance and repairs and the availability of, and our access to, necessary third-party services, such as gathering, processing, compression and transportation services. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operation and capital costs, which could have a material adverse effect on our business, financial condition and results of operations.

SEC rules could limit our ability to book additional PUDs in the future.

SEC rules require that, subject to limited exceptions, PUDs may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement has limited and may continue to limit our ability to book additional PUDs as we pursue our drilling program. Moreover, we may be required to write down our PUDs if we do not drill or plan on delaying those wells within the required five-year timeframe.

The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.

At December 31, 2018, approximately 60% of our total estimated proved reserves were classified as proved undeveloped. The development of our estimated proved undeveloped reserves of 208,395 MBoe will require an estimated \$1.9 billion of development capital over the next five years.

Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. The future development of our proved undeveloped reserves is dependent on future commodity prices, costs and economic assumptions that align with our internal forecast, as well as access to liquidity sources, such as the capital markets, our revolving credit facility and derivative contracts. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved undeveloped reserves as unproved reserves.

We participate in oil and gas leases with third parties who may not be able to fulfill their commitments to our projects.

We own less than 100% of the working interest in the oil and gas leases on which we conduct operations, and other parties will own the remaining portion of the working interest. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person. We could be held liable for joint activity obligations of other working interest owners, such as nonpayment of costs and liabilities arising from the actions of other working interest owners. In addition, declines in oil, natural gas and NGL prices may increase the likelihood that some of these working interest owners, particularly those that are smaller and less established, are not able to fulfill their joint activity obligations. A partner may be unable or unwilling to pay its share of project costs, and, in some cases, a partner may declare bankruptcy. In the event any of our project partners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial position.

We own non-operating interests in properties developed and operated by third parties, and as a result, we are unable to control the operation and profitability of such properties.

We participate in the drilling and completion of wells with third-party operators that exercise exclusive control over such operations. As a participant, we rely on the third-party operators to successfully operate these properties pursuant to joint operating agreements and other similar contractual arrangements.

As a participant in these operations, we may not be able to maximize the value associated with these properties in the manner we believe appropriate, or at all. For example, we cannot control the success of drilling and development activities on properties operated by third parties, which depend on a number of factors under the control of a third-party operator, including such operator's determinations with respect to, among other things, the nature and timing of drilling and operational activities, the timing and amount of capital expenditures and the selection of suitable technology. In addition, the third-party operator's operational expertise and financial resources and its ability to gain the approval of other participants in drilling wells will impact the timing and potential success of drilling and development activities in a manner that we are unable to control. A third-party operator's failure to adequately perform operations, breach of the applicable agreements or failure to act in ways that are favorable to us could reduce our production and revenues, negatively impact our liquidity and cause us to spend capital in excess of our current plans, and have a material adverse effect on our financial condition and results of operations.

If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value for a significant period of time, we will be required to take write-downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors such as lease expirations, changes in drilling plans and adverse drilling results, we may be required to write down the carrying value of our properties. A write down constitutes a non-cash charge to earnings. If market or other economic conditions deteriorate or if oil, natural gas and NGL prices continue to decline, we may incur impairment charges in 2019 or later periods, which may have a material adverse effect on our results of operations.

Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploitation, development and exploration activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or

acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected.

Conservation measures and technological advances could reduce demand for oil, natural gas and NGL.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil, natural gas and NGL, technological advances in fuel economy and energy generation devices could reduce demand for oil, natural gas and NGL. The impact of the changing demand for oil and gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

We depend upon several significant purchasers for the sale of most of our oil and natural gas production. The loss of one or more of these purchasers could, among other factors, limit our access to suitable markets for the oil, natural gas and NGL we produce.

The availability of a ready market for any oil, natural gas and NGL we produce depends on numerous factors beyond the control of our management, including but not limited to the extent of domestic production and imports of oil, the proximity and capacity of pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of oil and gas sold in interstate commerce. In addition, we depend upon several significant purchasers for the sale of most of our oil and natural gas production. See “Business—Operations—Marketing and Customers.” We cannot assure you that we will continue to have ready access to suitable markets for our future oil and natural gas production.

The inability of one or more of our purchasers to meet their obligations may adversely affect our financial results.

We have exposure to credit risk through receivables from purchasers of our oil, natural gas and NGL production. Two, three and four purchasers accounted for more than 10% of our revenues in the years ended December 31, 2018, 2017 and 2016, respectively. This concentration of purchasers may impact our overall credit risk in that these entities may be similarly affected by changes in economic conditions or commodity price fluctuations. We do not require our customers to post collateral. The inability or failure of our significant purchasers to meet their obligations to us or their insolvency or liquidation may materially adversely affect our financial condition and results of operations.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations.

Our exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the risk of fire, explosions, blowouts, surface cratering, uncontrollable flows of natural gas, oil and formation water, pipe or pipeline failures, abnormally pressured formations, casing collapses and environmental hazards such as oil spills, natural gas leaks, pipeline and tank ruptures or unauthorized discharges of toxic gases or other pollutants.

Any of these risks could adversely affect our ability to conduct operations or result in substantial loss to us as a result of claims for:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. Moreover, insurance may not be available in the future at commercially reasonable costs and on commercially reasonable terms. Also, pollution and other environmental risks generally are not fully insurable. The occurrence of an event that is not covered or fully covered by insurance and any delay in the payment of

insurance proceeds for covered events could have a material adverse effect on our business, financial condition and results of operations.

Properties that we decide to drill may not yield oil, natural gas or NGL in commercially viable quantities.

Properties that we decide to drill that do not yield oil, natural gas or NGL in commercially viable quantities will adversely affect our results of operations and financial condition. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of micro-seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects. Further, our drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or lost circulation in formations;
- equipment failure or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and
- increase in the cost of, shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services.

We may be unable to make accretive acquisitions or successfully integrate acquired businesses or assets, and any inability to do so may disrupt our business and hinder our ability to grow.

In the future we may make acquisitions of oil and gas properties or businesses that complement or expand our current business. The successful acquisition of oil and gas properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil, natural gas and NGL prices and their applicable differentials;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain and we may not be able to identify accretive acquisition opportunities. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Reviews may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when a review is performed. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an “as is” basis. Even if we do identify accretive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

The success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, our debt arrangements will impose certain limitations on our ability to enter into mergers or combination transactions. Our debt arrangements will also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions.

We may incur losses as a result of title defects in the properties in which we invest.

It is our practice in acquiring oil and natural gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest at the time of acquisition. Rather, we rely upon the judgment of lease brokers or land men who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we do typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

We are subject to stringent environmental and health and safety laws and regulations that could expose us to significant costs and liabilities.

Our oil and natural gas exploration, development and production operations are subject to numerous stringent and complex federal, state and local laws and regulations governing safety and health aspects of our operations, the release, disposal or discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations applicable to our operations including the acquisition of a permit before conducting drilling and other regulated activities; the restriction of types, quantities and concentration of materials that may be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the EPA and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring costly actions. For example, on May 2, 2017, following an incident in Firestone, Colorado, the COGCC issued a Notice to Operators (the “Notice”) that, among other things, required operators of oil and natural gas wells in Colorado: (i) by May 30, 2017, to re-inspect all existing flowlines and pipelines located within 1,000 feet of a defined “building unit,” which term includes residences and certain commercial facilities, to identify the well API number and tank battery location ID number associated with each line; (ii) by May 30, 2017, to inspect all existing flowlines and pipelines, regardless of distance to a “building unit,” to verify that any existing flowline or pipeline not in use, regardless of when it was installed or taken out of service, is abandoned in conformity with applicable rules; (iii) by June 30, 2017, to ensure and document that all flowlines within 1,000 feet of a “building unit” have integrity; and (iv) by June 30, 2017, to complete abandonment of any flowline or pipeline not actively operated, regardless of distance to a “building unit,” and regardless of when it was installed or taken out of service, in conformity with the applicable rules and the Notice. In August 2017, the Governor of Colorado announced several policy initiatives designed to enhance public safety that are to be implemented through rulemaking or legislation. On February 13, 2018, the COGCC approved new oil and natural gas flowline requirements, which include: (i) requirements for more-detailed tracking, location data, and record-keeping for flowlines that carry fluids away from a specific oil and gas location; (ii) requirements that any flowlines not in use, but not yet abandoned, are locked and marked and must continue to undergo integrity testing under the same standards as active lines until abandonment, and any risers associated with abandoned flowlines must be cut below grade; (iii) more-detailed requirements for operators to demonstrate flowline integrity, including updated standards for integrity-testing lines, more testing options that align with newer technology, and the elimination of pressure-testing exemptions for low-pressure lines; and (iv) requirements for full operator participation in the Utility Notification Center of Colorado’s “one-call” program to ensure a centralized home for all data on flowline locations and access to that information through the established 811 “call-before-you-dig” system. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory, remedial or corrective obligations, the occurrence of delays in permitting or development of projects and the issuance of orders limiting or prohibiting some or all of our operations in a particular area or forcing future compliance with environmental requirements.

The performance of our operations may result in significant environmental costs and liabilities due to our handling of petroleum hydrocarbons and other hazardous substances and wastes, as a result of air emissions and wastewater discharges related to our operations, and because of historical operations and waste disposal practices at our leased and owned properties. Spills or other releases of regulated substances could expose us to material losses, expenditures and liabilities under environmental laws and regulations. Under certain of such laws and regulations, we could be subject to strict, joint and several liability for the removal or remediation of previously released materials or property contamination, regardless of whether we were responsible for the release or contamination and even if our operations met previous standards in the industry at the time they were conducted. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly well drilling, construction, completion or water management activities, air emissions control or waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our results of operations, competitive position or financial condition. We may not be able to recover some or any of our costs with respect to such developments from

insurance. See “Business—Regulation of Environmental and Safety and Health Matters” for a further description of environmental and safety and health laws and regulations that affect us.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil, natural gas and NGL prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

Should we fail to comply with all applicable regulatory agency administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the EPA Act 2005, FERC has civil penalty authority under the NGA and NGPA to impose penalties for current violations of up to \$1.0 million per day for each violation. FERC may also impose administrative and criminal remedies and disgorgement of profits associated with any violation. While our operations have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting requirements. We also must comply with the anti-market manipulation rules enforced by FERC. Additional rules and regulations pertaining to those and other matters may be considered or adopted by FERC from time to time. Additionally, the FTC has regulations intended to prohibit market manipulation in the petroleum industry with authority to fine violators of the regulations civil penalties of up to \$1.0 million per day, and the CFTC prohibits market manipulation in the markets regulated by the CFTC, including similar anti-manipulation authority with respect to oil swaps and futures contracts as that granted to the CFTC with respect to oil purchases and sales. The CFTC rules subject violators to a civil penalty of up to the greater of \$1 million or triple the monetary gain to the person for each violation. Failure to comply with those regulations in the future could subject us to civil penalty liability, as described in “Business—Regulation of the Oil and Gas Industry.”

We may be involved in legal proceedings that could result in substantial liabilities.

Like many oil and gas companies, we are from time to time involved in various legal and other proceedings, such as title, royalty or contractual disputes, regulatory compliance matters and personal injury or property damage matters, in the ordinary course of our business. Additionally, citizen groups have brought and, in certain instances, may continue to bring legal proceedings against us to challenge our ability to receive environmental permits that we need to operate. Such legal proceedings are inherently uncertain and their results cannot be predicted. Regardless of the outcome, such proceedings could have an adverse impact on us because of legal costs, diversion of management and other personnel and other factors. In addition, it is possible that a resolution of one or more such proceedings could result in liability, loss of necessary environmental permits, penalties or sanctions, as well as judgments, consent decrees or orders requiring a change in our business practices, which could materially and adversely affect our business, operating results and financial condition. Accruals for such liability, penalties or sanctions may be insufficient. Judgments and estimates to determine accruals or range of losses related to legal and other proceedings could change from one period to the next, and such changes could be material.

Climate change legislation or regulations restricting emissions of GHG could result in increased operating costs and reduced demand for the oil, natural gas and NGL that we produce.

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHG. These efforts have included consideration of cap-and-trade programs, carbon taxes and GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources.

At the federal level, no comprehensive climate change legislation has been implemented to date. However, the EPA has adopted rules under authority of the CAA that, among other things, establish PSD construction and Title V permit reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal pollutant emissions, which reviews could require meeting “best available control technology” standards for those emissions. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, including, among other things, onshore producing facilities, which include certain of our operations. Federal agencies also have begun directly regulating emissions of methane from oil and natural gas operations,

with the EPA publishing NSPS Subpart OOOOa standards in June 2016 that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions and the BLM publishing requirements in November 2016 to reduce methane emissions from venting, flaring, and leaking on public lands. In September 2018, both of the EPA and BLM took steps to relax or rescind certain requirements under their respective methane rules. EPA proposed amendments that would relax requirements of the NSPS OOOOa standards and BLM issued a rule that relaxes or rescinds requirements of its November 2016 regulations. California and New Mexico have challenged BLM's September 2018 rule in ongoing litigation. Additionally, in December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France preparing an agreement requiring member countries to review and “represent a progression” in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. This “Paris Agreement” was signed by the United States in April 2016 and entered into force in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions, but rather includes pledges to voluntarily limit or reduce future emissions. In follow-up to an earlier announcement by President Trump, in August 2017, the U.S. Department officially informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States’ adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time.

The adoption and implementation of any international, federal or state legislation or regulations that require reporting of GHG or otherwise limit emissions of GHG from, our equipment and operations could result in increased costs to reduce emissions of GHG associated with our operations as well as delays or restrictions in our ability to permit GHG emissions from new or modified sources. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil, natural gas and NGL we produce and lower the value of our reserves, which devaluation could be significant. One or more of these developments could have a materially adverse effect on our business, financial condition and results of operations. Finally, notwithstanding potential risks related to climate change, the International Energy Agency, an autonomous intergovernmental organization involved in international energy policy, estimates that global energy demand will continue to rise and will not peak until after 2040 and oil and gas will continue to represent a substantial percentage of global energy use over that time. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. Please read “Business-Regulation of Environmental and Safety and Health Matters-Regulation of Greenhouse Gas (“GHG”) Emissions” for a further description of the laws and regulations relating to climate change that affect us.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and oil from dense subsurface rock formations. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemical additives under pressure into targeted geological formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing is typically regulated by state oil and natural gas commissions or similar state agencies but several federal agencies have asserted regulatory authority over certain aspects of the process. In addition, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances. Also, from time to time, the U.S. Congress has considered, but not adopted, legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. At the state level, Colorado, where we conduct operations, is among the states that has adopted, and other states are considering adopting, regulations that impose new or more stringent permitting, disclosure or well-construction requirements on hydraulic fracturing operations. States may elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York. In addition to state laws, local land use restrictions may restrict drilling or the hydraulic fracturing and cities may adopt local ordinances allowing hydraulic fracturing activities within their jurisdictions but regulating the time, place and manner of those activities. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, including, for example, on federal and American Indian lands, we could incur potentially significant added cost to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling wells.

Moreover, because most of our operations are conducted in a particular area, the DJ Basin in Colorado, legal restrictions imposed in that area will have a significantly greater adverse effect than if we had our operations spread out amongst several diverse geographic areas. Consequently, in the event that local or state restrictions or prohibitions are adopted

in the DJ Basin in Colorado that impose more stringent limitations on the production and development of oil and natural gas, we may incur significant costs to comply with such requirements or may experience delays or curtailment in the pursuit of exploration, development, or production activities, and possibly be limited or precluded in the drilling of wells or in the amounts that we are ultimately able to produce from our reserves. Any such increased costs, delays, cessations, restrictions or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

Please read “Business—Regulation of Environmental and Safety and Health Matters—Hydraulic Fracturing Activities” for a further description of the laws and regulations relating to hydraulic fracturing that affect us.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties and market oil or natural gas.

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, and raising additional capital, which could have a material adverse effect on our business.

Our undeveloped acreage must be drilled before lease expiration to hold the acreage by production. In highly competitive markets for acreage, failure to drill sufficient wells to hold acreage could result in a substantial lease renewal cost or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Unless production is established within the spacing units covering the undeveloped acres on which some of our drilling locations are identified, our leases for such acreage will expire. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. As such, our actual drilling activities may differ materially from our current expectations, which could adversely affect our business. These risks are greater at times and in areas where the pace of our exploration and development activity slows.

Declining general economic, business or industry conditions may have a material adverse effect on our results of operations, liquidity and financial condition.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit and the United States financial market have contributed to increased economic uncertainty and diminished expectations for the global economy. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. These factors, combined with volatile commodity prices, declining business and consumer confidence and increased unemployment, have precipitated an economic slowdown and a recession. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which we can sell our production, affect the ability of our vendors, suppliers and customers to continue operations and ultimately adversely impact our results of operations, liquidity and financial condition.

The loss of senior management or technical personnel could adversely affect operations.

We depend on the services of our senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. The loss of the services of our senior management or technical personnel could have a material adverse effect on our business, financial condition and results of operations.

We are susceptible to the potential difficulties associated with rapid growth and expansion and have a limited operating history.

We have grown rapidly since we began operations in late 2012. Our management believes that our future success depends on our ability to manage the rapid growth that we have experienced and the demands from increased responsibility on management personnel. The following factors could present difficulties:

- increased responsibilities for our executive level personnel;
- increased administrative burden;
- increased capital requirements; and

- increased organizational challenges common to large, expansive operations.

Our operating results could be adversely affected if we do not successfully manage these potential difficulties. The historical financial information incorporated herein is not necessarily indicative of the results that may be realized in the future. In addition, our operating history is limited and the results from our current producing wells are not necessarily indicative of success from our future drilling operations.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. Potential disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

Adverse weather conditions may negatively affect our operating results and our ability to conduct drilling activities.

Adverse weather conditions may cause, among other things, increases in the costs of, and delays in, drilling or completing new wells, power failures, temporary shut-in of production and difficulties in the transportation of our oil, natural gas and NGL. Any decreases in production due to poor weather conditions will have an adverse effect on our revenues, which will in turn negatively affect our cash flow from operations.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners for use in our operations. Drought conditions have led governmental authorities to restrict the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supplies. If we are unable to obtain water to use in our operations from local sources, we may be unable to produce oil, natural gas and NGL economically, which could have an adverse effect on our financial condition, results of operations and cash flows.

Restrictions on drilling activities intended to protect certain species of wildlife and natural resources may adversely affect our ability to conduct drilling activities areas where we operate.

Oil and natural gas operations in our operating areas may be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife and natural resources. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations or materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have a material adverse impact on our ability to develop and produce our reserves.

The enactment of derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Act, enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and of entities, such as us, that participate in that market. The Dodd-Frank Act requires the CFTC and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. In its rulemaking under the Dodd-Frank Act, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time. The Dodd-Frank Act and CFTC rules also will require us, in connection with certain derivatives activities, to comply with clearing and trade-execution requirements (or to take steps to qualify for an exemption to such requirements). In addition, the CFTC and certain banking regulators have recently adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for the end-user exception to the mandatory clearing, trade-execution and margin requirements for swaps entered to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, if any of our swaps do not qualify for the commercial end-user exception, posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flow. It is not possible at this time to predict with certainty the full effects of the Dodd-Frank Act and CFTC rules on us or the timing of such effects. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and CFTC rules, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil, natural gas and NGL prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil, natural gas and NGL. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and CFTC rules is to lower commodity prices. Any of these consequences could have a material and adverse effect on us, our financial condition or our results of operations. In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations, the impact of which is not clear at this time.

Recent changes in United States federal income tax law may have an adverse effect on our cash flows, results of operations or financial condition overall.

The final version of the tax reform bill commonly known as the Tax Cuts and Jobs Act (the "TCJA") signed into law on December 22, 2017 may affect our cash flows, results of operations and financial condition. Among other items, the TCJA repealed the deduction for certain U.S. Production activities and provided for a new limitation on the deduction for interest expense. Given the scope of this law and the potential interdependency of its changes, it is difficult at this time to assess whether the overall effect of the TCJA will be cumulatively positive or negative for our earnings and cash flow, but such changes may adversely impact our financial results.

Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated as a result of future legislation.

In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including to certain key U.S. federal income tax provisions currently available to oil and gas companies. Although none of these changes were included in the TCJA, future adverse changes could include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures. Congress could consider, and could include, some or all of these proposals as part of future tax reform legislation. The passage of any legislation as a result of these proposals or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available with respect to oil and gas development, or increase costs, and any such changes could have an adverse effect on the Company's financial position, results of operations and cash flows.

We may not be able to keep pace with technological developments in our industry.

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage or may be forced by competitive pressures to implement those new technologies at

substantial costs. In addition, other oil and natural gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and that may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete, our business, financial condition or results of operations could be materially and adversely affected.

Our business could be negatively affected by security threats, including cybersecurity threats, destructive forms of protest and opposition by activists and other disruptions.

As an oil and natural gas producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information, to misappropriate financial assets or to render data or systems unusable; threats to the security of our facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of financial assets, sensitive information, critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. These events could lead to financial losses from remedial actions, loss of business or potential liability. In addition, destructive forms of protest and opposition by activists and other disruptions, including acts of sabotage or eco-terrorism, against oil and gas production and activities could potentially result in damage or injury to people, property or the environment or lead to extended interruptions of our operations, adversely affecting our financial condition and results of operations.

Loss of our information and computer systems could adversely affect our business.

We are dependent on our information systems and computer-based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include our loss of communication links, inability to find, produce, process and sell oil and natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

Risks Related to our Common Stock

The requirements of being a public company, including compliance with the reporting requirements of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management, and we may be unable to comply with these requirements in a timely or cost-effective manner.

We completed our IPO in October 2016. As a public company, we must comply with various laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act, related regulations of the SEC and the requirements of the NASDAQ, with which we were not required to comply as a private company. Complying with these statutes, regulations and requirements will occupy a significant amount of time of our board of directors and management and will significantly increase our costs and expenses. We are now required to:

- institute a more comprehensive compliance function;
- comply with rules promulgated by the NASDAQ;
- continue to prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;
- establish new internal policies, such as those relating to insider trading; and
- involve and retain to a greater degree outside counsel and accountants in the above activities.

Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations.

Moreover, if we are not able to comply with the requirements of Section 404 in a timely manner, or if in the future we or our independent registered public accounting firm identifies deficiencies in our internal controls over financial reporting that are deemed to be material weaknesses, the market price of our stock could decline, and we could be subject to sanctions or investigations by the SEC or other regulatory authorities, which would require additional financial and management resources.

In addition, we expect that being a public company subject to these rules and regulations may make it more difficult and more expensive for us to obtain director and officer liability insurance and we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for us to attract and retain qualified individuals to serve on our board of directors or as executive officers.

If we fail to develop or maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. If one or more material weaknesses emerge related to financial reporting, or if we otherwise fail to establish and maintain effective internal control over financial reporting, our ability to accurately report our financial results could be adversely affected. As a result, current and potential stockholders could lose confidence in our financial reporting, which would harm our business and the trading price of our common stock.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our common stock.

Yorktown's funds collectively hold a substantial portion of the voting power of our common stock.

Yorktown's funds currently collectively hold approximately 28% of our common stock. See "Security Ownership of Certain Beneficial Owners and Management" for more information regarding ownership of our common stock by the Yorktown funds. The existence of affiliated stockholders with significant aggregate holdings that may act as a group may have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of our company. Moreover, this concentration of stock ownership may adversely affect the trading price of our common stock to the extent investors perceive a disadvantage in owning stock of a company with affiliated stockholders with significant aggregate holdings that may act as a group.

Conflicts of interest could arise in the future between us, on the one hand, and Yorktown and its affiliates, including its funds and their respective portfolio companies, on the other hand, concerning among other things, potential competitive business activities or business opportunities.

Yorktown's funds are in the business of making investments in entities in the U.S. energy industry. As a result, Yorktown's funds may, from time to time, acquire interests in businesses that directly or indirectly compete with our business, as well as businesses that are significant existing or potential customers. Yorktown's funds and their respective portfolio companies may acquire or seek to acquire assets that we seek to acquire and, as a result, those acquisition opportunities may not be available to us or may be more expensive for us to pursue. Under our certificate of incorporation, Yorktown's funds and/or one or more of their respective affiliates are permitted to engage in business activities or invest in or acquire businesses which may compete with our business or do business with any client of ours. Any actual or perceived conflicts of interest with respect to the foregoing could have an adverse impact on the trading price of our common stock.

Our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock in addition to the Series A Preferred Stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our certificate of incorporation and bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- limitations on the removal of directors;

- limitations on the ability of our stockholders to call special meetings;
- establishing advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders; and
- providing that the board of directors is expressly authorized to adopt, or to alter or repeal our bylaws.

We do not intend to pay dividends on our common stock, and our debt arrangements and the Series A Preferred Stock place certain restrictions on our ability to do so. Consequently, it is possible that the only opportunity to achieve a return on an investment in our common stock will be if the price of our common stock appreciates.

We do not plan to declare dividends on shares of our common stock in the foreseeable future. Additionally, our debt arrangements and the Series A Preferred Stock restrict our ability to pay cash dividends. Consequently, it is possible that the only opportunity to achieve a return on an investment in our common stock will be if shareholders sell their common stock at a price greater than they paid for it. There is no guarantee that the price of our common stock that will prevail in the market will ever exceed the price that such investors paid for our common stock.

Future sales of our common stock could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute the ownership in us by current shareholders.

We may sell additional shares of common stock in public or private offerings. We may also issue additional shares of common stock or convertible securities. Excluding any shares of common stock issued upon the conversion of our Series A Preferred Stock including any shares of Series A Preferred Stock that may be issued pursuant to our option to pay dividends on the Series A Preferred Stock in kind pursuant to the terms of the Certificate of Designations setting forth the terms of the Series A Preferred Stock, we have 171,666,485 outstanding shares of common stock as of December 31, 2018. In connection with the IPO, we filed a registration statement with the SEC on Form S-8 providing for the registration of 23,000,000 shares of our common stock issued or reserved for issuance under our equity incentive plan. Subject to the satisfaction of vesting conditions, the expiration of lock-up agreements and the requirements of Rule 144, shares registered under the registration statement on Form S-8 will be available for resale immediately in the public market without restriction. Additionally, the Series A Preferred Stock are convertible into shares of our common stock pursuant to their terms.

We cannot predict the size of future issuances of our common stock or securities convertible into common stock or the effect, if any, that future issuances and sales of shares of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

We may issue additional preferred stock whose terms could adversely affect the voting power or value of our common stock.

Our certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock, including the Series A Preferred Stock, could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our common stock or if our operating results do not meet their expectations, our stock price could decline.

The trading market for our common stock will be influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrades our common stock or if our operating results do not meet their expectations, our stock price could decline.

Our certificate of incorporation designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or agents.

Our certificate of incorporation provides that unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will, to the fullest extent permitted by applicable law, be the sole and exclusive forum for (i) any derivative action or proceeding brought on our behalf, (ii) any action asserting a claim for a breach of a fiduciary duty owed by any of our directors, officers, employees or agents to us or our stockholders, (iii) any action asserting a claim arising pursuant to any provision of the Delaware General Corporation Law, our certificate of incorporation or our bylaws, or (iv) any action asserting a claim against us that is governed by the internal affairs doctrine, in each such case subject to such Court of Chancery having personal jurisdiction over the indispensable parties named as defendants therein. Any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock will be deemed to have notice of, and consented to, the provisions of our certificate of incorporation described in the preceding sentence. This choice of forum provision may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers, employees or agents, which may discourage such lawsuits against us and such persons. Alternatively, if a court were to find these provisions of our certificate of incorporation inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition or results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

We have no unresolved comments from the SEC staff regarding our periodic or current reports under the Exchange Act.

ITEM 3. LEGAL PROCEEDINGS

From time to time, we may be involved in litigation relating to claims arising out of our business and operations in the normal course of business. While the outcomes 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 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information.

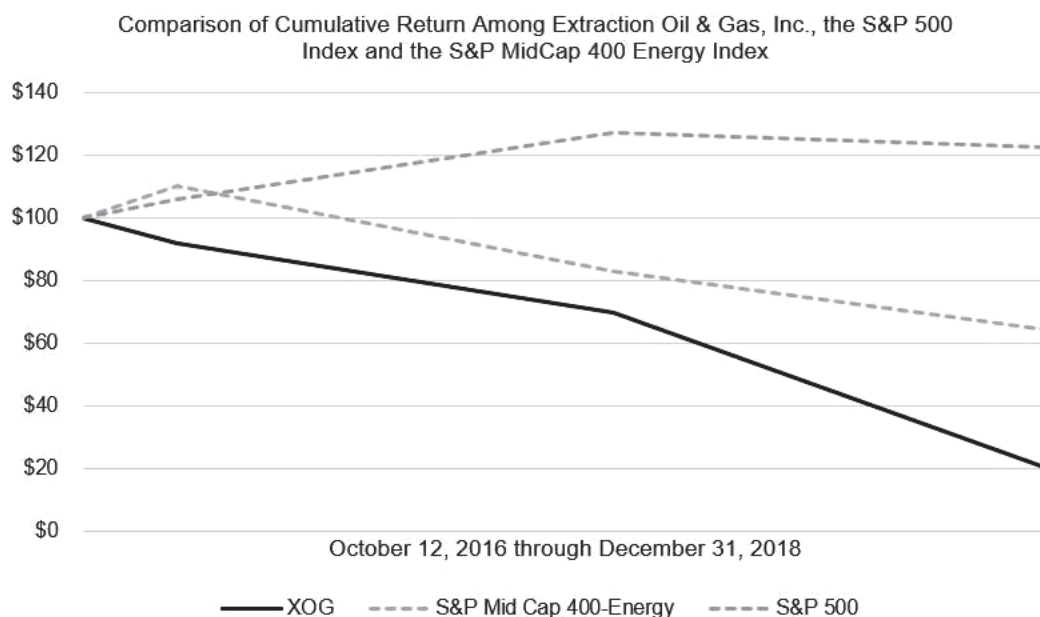
Our common stock is currently traded on the NASDAQ under the ticker symbol "XOG."

Dividend Policy

We have not historically paid, and do not anticipate paying any cash dividends in the future, to common stockholders of our common stock. In addition, our revolving credit facility, our Senior Notes (collectively, our "debt arrangements") and the Series A Preferred Stock place certain restrictions on our ability to pay cash dividends. Please see *Note 5 — Long Term Debt* included in the notes to the consolidated financial statements included elsewhere in this Annual Report for more information regarding the restrictions placed on our ability to pay cash dividends.

Comparison of Cumulative Return

The following graph compares the cumulative total shareholder return on a \$100 investment in our common stock on October 12, 2016 through December 31, 2018, to that of the cumulative return on a \$100 investment in the S&P 500 Composite for the same period. In calculating the cumulative return, reinvestment of dividends, if any, is assumed. The indices are included for comparative purpose only. This graph is not "soliciting material," is not deemed filed with the SEC and is not to be incorporated by reference in any of our filings under the Securities Act or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language in any such filing.



Holders

Pursuant to the records of the transfer agent, as of February 19, 2019, the number of holders of record of our common stock was 60.

Sales of Unregistered Securities

We did not have any sales of unregistered securities during the fiscal year ended December 31, 2018.

Issuer Purchases of Equity Securities

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

Period	Total Number of Shares Purchased	Average Price Paid per Share
October 1, 2018 - October 31, 2018	—	\$ —
November 1, 2018 - November 30, 2018	3,558,145	6.68
December 1, 2018 - December 31, 2018	500,000	4.97
Total	4,058,145	\$ 6.47

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth selected consolidated financial data as of and for the five-years ended December 31, 2018. The data as of and for the fiscal years ended December 31 for each respective year was derived from our historical consolidated financial statements and the accompanying notes included elsewhere in this Annual Report.

The following selected consolidated financial information should be read in conjunction with “Item 7. Management’s Discussion and Analysis of Financial Conditions and Results of Operations” and the consolidated financial statements and the notes thereto included in “Item 8. Financial Statements and Supplementary Data” presented elsewhere in this Annual Report for further discussion of the factors affecting the comparability of the Company’s financial data. Also see “Recent Accounting Pronouncements” included in the notes to the consolidated financial statements included elsewhere in this Annual Report.

	For the Year Ended December 31,				
	2018	2017	2016	2015	2014
	(in thousands, except per share data)				
Revenues:					
Oil sales	\$ 840,687	\$ 419,904	\$ 194,059	\$ 157,024	\$ 75,460
Natural gas sales	105,629	92,322	48,652	26,019	9,247
NGL sales	114,427	92,070	35,378	14,707	8,133
Total Revenues	1,060,743	604,296	278,089	197,750	92,840
Operating Expenses:					
Lease operating expenses	79,413	60,358	36,743	23,949	5,067
Transportation and gathering	39,411	50,948	25,300	6,679	—
Production taxes	90,345	51,367	20,730	17,035	9,743
Exploration expenses	31,611	36,256	36,422	18,636	126
Depletion, depreciation, amortization and accretion	435,775	314,999	205,348	146,547	34,042
Impairment of long lived assets and goodwill	70,928	1,647	23,425	15,778	—
Other operating expenses	—	—	10,891	2,353	—
(Gain) loss on sale of property and equipment and assets of unconsolidated subsidiary	(136,834)	451	—	—	—
Acquisition transaction expenses	—	—	2,719	6,000	—
General and administrative expenses	134,604	110,167	232,388	37,149	19,598
Total Operating Expenses	745,253	626,193	593,966	274,126	68,576
Operating Income (Loss)	315,490	(21,897)	(315,877)	(76,376)	24,264
Other Income (Expense):					
Commodity derivatives gain (loss)	(8,554)	(36,332)	(100,947)	79,932	48,008
Interest expense	(123,330)	(51,889)	(68,843)	(51,030)	(22,454)
Other income	5,099	2,010	386	210	24
Total Other Income (Expense)	(126,785)	(86,211)	(169,404)	29,112	25,578
Income (Loss) Before Income Taxes	188,705	(108,108)	(485,281)	(47,264)	49,842
Income tax (expense) benefit ⁽¹⁾	(66,850)	63,700	29,280	—	—
Net Income (Loss)	\$ 121,855	\$ (44,408)	\$ (456,001)	\$ (47,264)	\$ 49,842
Net income attributable to noncontrolling interest	7,287	—	—	—	—
Net Income (Loss) Attributable to Extraction Oil & Gas, Inc.	114,568	(44,408)	(226,107)	(47,264)	49,842
Adjustments to reflect Series A Preferred Stock dividends and accretion of discount	(16,869)	(16,279)	(3,999)	—	—
Net Income (Loss) Available to Common Shareholders, Basic and Diluted	\$ 97,699	\$ (60,687)	\$ (230,106)	\$ (47,264)	\$ 49,842
Income (Loss) Per Common Share ⁽²⁾					
Basic and diluted	\$ 0.56	\$ (0.35)	\$ (1.54)		

Selected consolidated financial information continued:

	As of and for the Year Ended December 31,				
	2018	2017	2016	2015	2014
Total Production Volumes:					
Oil (MBbls)	14,679	9,594	5,287	3,946	1,022
Natural Gas (MMcf)	46,847	32,395	20,212	10,823	2,664
NGL (MBbls)	5,260	3,901	2,284	1,335	325
Total (MBOE)	27,747	18,894	10,940	7,084	1,792
Average net sales (BOE/d)	76,019	51,764	29,891	19,408	4,908
Proved Reserves:					
Oil (MBbls)	135,846	111,275	90,995	71,500	45,165
Natural Gas (MMcf)	703,268	626,169	507,735	292,584	166,416
NGL (MBbls)	94,851	77,106	62,448	38,383	19,451
Total (MBOE)	347,908	292,743	238,066	158,647	92,352
Consolidated Cash Flow Information:					
Net cash provided by operating activities ⁽⁵⁾	\$ 684,933	\$ 316,965	\$ 120,688	\$ 166,683	\$ 77,390
Net cash used in investing activities ⁽⁵⁾	\$ (897,305)	\$ (1,404,528)	\$ (873,608)	\$ (530,077)	\$ (960,569)
Net cash provided by financing activities	\$ 440,590	\$ 463,395	\$ 1,286,750	\$ 371,404	\$ 972,090
Consolidated Balance Sheet Information:					
Total Assets	\$ 4,166,027	\$ 3,384,669	\$ 2,784,776	\$ 1,634,140	\$ 1,201,069
Long-term Debt	\$ 1,417,659	\$ 1,023,361	\$ 538,141	\$ 637,790	\$ 508,903
Series A Preferred Stock	\$ 164,367	\$ 158,383	\$ 153,139	\$ —	\$ —
Total Equity ⁽³⁾	\$ 1,894,686	\$ 1,616,765	\$ 1,616,073	\$ 754,232	\$ 545,188
Other Financial Data ⁽⁴⁾:					
Adjusted EBITDAX	\$ 659,752	\$ 380,462	\$ 192,265	\$ 176,120	\$ 66,892

(1) Extraction Oil & Gas, Inc. is a subchapter C corporation ("C-Corp") under the Internal Revenue Code of 1986, as amended (the "Code"), and is subject to federal and State of Colorado income taxes. Our predecessor, Extraction Oil & Gas Holdings, LLC was not subject to U.S. federal income taxes. As a result, the consolidated net income (loss) in our historical financial statements for periods prior to our October 12, 2016 corporate reorganization to a C-Corp does not reflect the tax expense we would have incurred as a C-Corp during such periods.

(2) See *Note 9 — Equity* and *Note 12 — Earnings (Loss) Per Share* in our consolidated financial statements, included herein, for additional discussion regarding the calculation of income (loss) per share.

(3) Total Equity includes the noncontrolling interest of \$147.9 million associated with Elevation Preferred Units for the year ended December 31, 2018.

(4) Adjusted EBITDAX is a non-GAAP financial measure. Management defines 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 and goodwill, exploration expenses, rig termination fees, write off of deposit on acquisition, (gain) loss on sale of property and equipment, gain on sale of assets of unconsolidated subsidiaries, acquisition transaction expenses, (gain) loss on commodity derivatives, settlements on commodity derivative instruments, premiums paid for derivatives that settled during the period, unit and stock-based compensation expense, amortization of debt discount and debt issuance costs, make-whole premiums, interest expense, income tax expense (benefit) and non-recurring charges. See Part II, Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations, in this Annual Report for additional disclosures related to Adjusted EBITDAX.

(5) Includes the impact of Accounting Standard Update 2018-18 and 2018-15 on prior year data. See Part II, Item 8, Note 2—Basis of Presentation and Significant Accounting Policies

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our consolidated financial statements and related notes appearing in "Item 8. Financial Statements and Supplementary Data." The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil, natural gas and NGL, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report, particularly in "Risk Factors" and "Cautionary Note Regarding Forward-Looking Statements," all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

OVERVIEW

We are an independent oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves, as well as the construction and support of midstream assets to gather and process crude oil and gas production in the Rocky Mountain region, primarily in the Wattenberg Field of the Denver-Julesburg Basin (the "DJ Basin") of Colorado. We have developed an oil, natural gas and NGL asset base of proved reserves, as well as a portfolio of development drilling opportunities on high resource-potential leasehold on contiguous acreage blocks in 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.

Our Properties

We have assembled, as of December 31, 2018, approximately 179,300 net acres of large, contiguous acreage blocks in some of the most productive areas of what we consider to be the core of the DJ Basin as indicated by the results of our horizontal drilling program and the results of offset operators. Additionally, we hold approximately 138,100 net acres outside of what we consider our Core DJ Basin, which we refer to as our "Other Rockies Area," that we believe is prospective for many of the same formations as our properties in the Core DJ Basin. We operated 96% of our horizontal production for the year ended December 31, 2018, our total estimated proved reserves were approximately 347.9 MMBoe, of which approximately 40% were classified as proved developed reserves. For more information about our properties, please read "Business—Our Properties." in Items 1. and 2. of this Annual Report.

Financial Overview

For the year ended December 31, 2018, we had net income of \$121.9 million as compared to a net loss of \$44.4 million for the year ended December 31, 2017. The change to net income was primarily driven by an increase in sales revenues of \$456.4 million, partially offset by an increase in operating expenses of \$119.1 million, which includes the gain on sale of property and equipment and assets of unconsolidated subsidiary of \$136.8 million. Additionally, we had an increase in interest expense of \$71.4 million, which includes a make-whole premium of \$35.6 million and \$9.4 million of accelerated amortization expense upon the redemption of our 2021 Senior Notes.

For the year ended December 31, 2018, crude oil, natural gas and NGL sales, coupled with the impact of settled derivatives, increased to \$930.1 million as compared to \$585.7 million in the same prior year period due to an increase in sales volumes of 8,853 MBoe and an increase of \$2.52 in realized price per BOE, including settled derivatives.

Adjusted EBITDAX was \$659.8 million for the year ended December 31, 2018, as compared to \$380.5 million in the same period in 2017, reflecting a 73% increase. Adjusted EBITDAX is a non-GAAP financial measure. For a definition of Adjusted EBITDAX and a reconciliation to our most directly comparable financial measure calculated and presented in accordance with GAAP, please read "Adjusted EBITDAX."

Operational Overview

During the year ended December 31, 2018, we continued to focus on growing production while at the same time implementing operational efficiencies to reduce drilling and completion costs. We incurred approximately \$776.1 million in drilling 161 gross (129.7 net) wells with an average lateral length of 1.8 miles and completing 161 gross (137.4 net) wells with an average lateral length of 1.7 miles, all of which were horizontal wells in the DJ Basin. In addition, we incurred approximately \$116.4 million of leasehold and surface acreage additions, excluding acquisitions. These capital expenditures exclude the impact of the decrease in outstanding elections of \$6.7 million. In addition, Elevation Midstream, LLC, our wholly owned midstream subsidiary, incurred \$108.2 million of capital expenditures.

Income Taxes

On December 22, 2017, the TCJA was enacted making significant changes to the Internal Revenue Code. Many of the provisions in the TCJA have an effective date for years beginning after December 31, 2017, including the lowering of the U.S. corporate rate from 35% to 21%. As a result of the enactment date of December 22, 2017, we were required to remeasure the deferred tax assets and liabilities at the rate in which they are expected to reverse. We provisionally recorded an income tax benefit in the amount of \$23.4 million related to the remeasurement of the net deferred tax liability as of December 31, 2017. During the third quarter of 2018, we completed the accounting for the income tax effect of the TCJA's limit on compensation under Internal Revenue Code Sec. 162(m) and stock-based compensation for covered employees. This resulted in a \$0.4 million reduction in deferred tax assets that had been recorded as a provisional amount as of December 31, 2017. There are no remaining provision amounts associated with the TCJA as of December 31, 2018.

In connection with the IPO in October 2016, our accounting predecessor, Extraction Oil & Gas Holdings, LLC ("Holdings") was merged into the Company. Prior to this corporate reorganization, we were not subject to federal or state income taxes. Accordingly, the financial data attributable to us prior to such corporate reorganization contain no provision for federal or state income taxes because the tax liability with respect to Holdings' taxable income was passed through to our members. Beginning October 12, 2016, we began to be taxed as a C corporation under the Code, prior to the TCJA enactment, and subject to federal and state income taxes at a blended statutory rate of approximately 38% of pretax earnings.

How We Evaluate Our Operations

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

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

Sources of Our Revenues

Our revenues are derived from the sale of our oil and natural gas production, as well as the sale of NGL that are extracted from our natural gas during processing. Our oil, natural gas and NGL revenues do not include the effects of derivatives. For the year ended December 31, 2018, our revenues were derived 79% from oil sales, 10% from natural gas sales and 11% from NGL sales. For the year ended December 31, 2017, our revenues were derived 70% from oil sales, 15% from natural gas sales and 15% from NGL sales. For the year ended December 31, 2016, our revenues were derived 70% from oil sales, 17% from natural gas sales and 13% from NGL sales. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Sales Volumes

The following table presents historical sales volumes for our properties for the periods indicated:

	For the Year Ended December 31,		
	2018	2017	2016
Oil (MBbl)	14,679	9,594	5,287
Natural gas (MMcf)	46,847	32,395	20,212
NGL (MBbl)	5,260	3,901	2,284
Total (MBoe)	27,747	18,894	10,940
Average net sales (BOE/d)	76,019	51,764	29,891

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. We estimate that midstream constraints negatively impacted our production by approximately 18.5 MBOE/d, or 24%, during the year ended December 31, 2018. We are currently working with various midstream providers to address processing constraints in the DJ Basin. Please read “Risks Related to the Oil, Natural Gas and NGL Industry and Our Business” in Item 1A. of this 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 December 31, 2018, average daily prices for NYMEX West Texas Intermediate oil prices ranged from a high of \$107.26 per Bbl to a low of \$26.21 per Bbl. Average daily prices for NYMEX Henry Hub gas ranged from a high of \$6.15 per MMBtu to a low of \$1.64 per MMBtu during the same period. Declines in, and continued depression of, the price of oil and natural gas occurring during 2015 and also during 2018 are due to a combination of factors including increased U.S. supply, global economic concerns and geopolitical risks. These price variations can have a material impact on our financial results and capital expenditures.

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

Natural gas prices vary by region and locality, depending upon the distance to markets, availability of pipeline capacity and supply and demand relationships in that region or locality. The NYMEX Henry Hub price of natural gas is a widely used benchmark for the pricing of natural gas in the United States. Similar to oil, the actual prices realized from the sale of natural gas differ from the quoted NYMEX Henry Hub price as a result of quality and location differentials. For example, wet natural gas with a high Btu content sells at a premium to low Btu content dry natural gas because it yields a greater quantity of NGL. Location differentials to NYMEX Henry Hub prices result from variances in transportation costs based on the natural gas' proximity to the major consuming markets to which it is ultimately delivered. 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 Year Ended		
	December 31,		
	2018	2017	2016
Oil			
NYMEX WTI High (\$/Bbl)	\$ 76.41	\$ 60.42	\$ 54.06
NYMEX WTI Low (\$/Bbl)	\$ 42.53	\$ 42.53	\$ 26.21
NYMEX WTI Average (\$/Bbl)	\$ 64.90	\$ 50.85	\$ 43.47
Average Realized Price (\$/Bbl)	\$ 57.27	\$ 43.77	\$ 36.70
Average Realized Price, with derivative settlements (\$/Bbl)	\$ 48.04	\$ 41.67	\$ 40.59
Average Realized Price as a % of Average NYMEX WTI	88.2%	86.1%	84.4%
Differential (\$/Bbl) to Average NYMEX WTI	\$ (7.63)	\$ (7.08)	\$ (6.77)
Natural Gas			
NYMEX Henry Hub High (\$/MMBtu)	\$ 4.84	\$ 3.42	\$ 3.93
NYMEX Henry Hub Low (\$/MMBtu)	\$ 2.55	\$ 2.56	\$ 1.64
NYMEX Henry Hub Average (\$/MMBtu)	\$ 3.07	\$ 3.02	\$ 2.55
Average Realized Price (\$/Mcf) ⁽²⁾	\$ 2.25	\$ 2.85	\$ 2.41
Average Realized Price, with derivative settlements (\$/Mcf) ⁽²⁾	\$ 2.36	\$ 2.90	\$ 2.81
Average Realized Price as a % of Average NYMEX Henry Hub ⁽¹⁾⁽²⁾	66.7%	85.8%	85.9%
Differential (\$/Mcf) to Average NYMEX Henry Hub ⁽¹⁾⁽²⁾	\$ (1.12)	\$ (0.47)	\$ (0.40)
NGL			
Average Realized Price (\$/Bbl) ⁽²⁾	\$ 21.75	\$ 23.60	\$ 15.49
Average Realized Price as a % of Average NYMEX WTI ⁽²⁾	33.5%	46.4%	35.6%

- (1) Based on the difference between our average realized price and the NYMEX Henry Hub Average as converted into Mcf using a conversion factor of 1.1 to 1.
- (2) As a result of the adoption of ASC 606 - Revenue from Contracts with Customers ("ASC 606") on January 1, 2018, certain costs previously classified as transportation and gathering expenses are presented on a net basis for proceeds expected to be received. See "—Historical Results of Operations and Operating Expense" for more information.

Derivative Arrangements

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

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

instances require the payment of a premium, to reduce the effect of price changes on a portion of our future oil and natural gas production. We expect to continue to use a variety of hedging strategies and instruments for the foreseeable future.

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

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

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

We combine swaps, purchased put options, sold put options, and sold call options in order to achieve various hedging strategies. Some examples of our hedging strategies are collars which include purchased put options and sold call options, three-way collars which include purchased put options, sold put options, and sold call options, and enhanced swaps, which include either sold put options or sold call options with the associated premiums rolled into an enhanced fixed price swap. We have historically relied on commodity derivative contracts to mitigate our exposure to lower commodity prices.

We have historically been able to hedge our oil and natural gas production at prices that are significantly higher than current strip prices. However, in the current commodity price environment, our ability to enter into comparable derivative arrangements at favorable prices may be limited, and we are not obligated to hedge a specific portion of our oil or natural gas production. The following summarizes our derivative positions related to crude oil and natural gas sales in effect as of December 31, 2018:

	2019	2020
NYMEX WTI Crude Swaps:		
Notional volume (Bbl)	900,000	1,200,000
Weighted average fixed price (\$/Bbl)	\$ 52.56	\$ 52.66
NYMEX WTI Crude Sold Calls:		
Notional volume (Bbl)	11,700,000	1,800,000
Weighted average sold call price (\$/Bbl)	\$ 65.40	\$ 67.53
NYMEX WTI Crude Sold Puts:		
Notional volume (Bbl)	13,500,000	1,800,000
Weighted average sold put price (\$/Bbl)	\$ 41.27	\$ 42.00
NYMEX WTI Crude Purchased Puts:		
Notional volume (Bbl)	17,850,000	1,800,000
Weighted average purchased put price (\$/Bbl)	\$ 47.67	\$ 50.00
NYMEX HH Natural Gas Swaps:		
Notional volume (MMBtu)	32,400,000	—
Weighted average fixed price (\$/MMBtu)	\$ 2.81	—
NYMEX HH Natural Gas Purchased Puts:		
Notional volume (MMBtu)	3,600,000	—
Weighted average purchased put price (\$/MMBtu)	\$ 3.04	—
NYMEX HH Natural Gas Sold Calls:		
Notional volume (MMBtu)	3,600,000	—
Weighted average sold call price (\$/MMBtu)	\$ 3.46	—
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)	36,000,000	—
Weighted average fixed basis price (\$/MMBtu)	\$ (0.75)	—

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

	For the Year Ended December 31,		
	2018	2017	2016
NYMEX HH Natural Gas Swaps:			
Notional volume (MMBtu)	40,650,000	25,240,000	13,194,600
Weighted average fixed price (\$/MMBtu)	\$ 3.10	\$ 3.05	\$ 3.13
CIG Basis Gas Swaps:			
Notional volume (MMBtu)	37,935,000	12,615,000	2,970,000
Weighted average fixed basis price (\$/MMBtu)	\$ (0.62)	\$ (0.34)	\$ (0.19)
NYMEX HH Natural Gas Purchased Puts:			
Notional volume (MMBtu)	2,400,000	—	—
Weighted average strike price (\$/MMBtu)	\$ 3.00	—	—
NYMEX HH Natural Gas Sold Calls:			
Notional volume (MMBtu)	2,400,000	—	—
Weighted average strike price (\$/MMBtu)	\$ 3.15	—	—
NYMEX WTI Crude Swaps:			
Notional volume (Bbl)	5,050,000	4,125,000	1,989,060
Weighted average fixed price (\$/Bbl)	\$ 51.58	\$ 48.02	\$ 41.87
NYMEX WTI Crude Sold Puts:			
Notional volume (Bbl)	13,388,800	7,720,000	2,100,000
Weighted average strike price (\$/Bbl)	\$ 39.09	\$ 37.67	\$ 44.93
NYMEX WTI Crude Purchased Puts:			
Notional volume (Bbl)	12,327,600	5,570,000	4,724,150
Weighted average strike price (\$/Bbl)	\$ 44.81	\$ 45.18	\$ 51.82
NYMEX WTI Crude Sold Calls:			
Notional volume (Bbl)	10,090,000	4,620,000	2,786,090
Weighted average strike price (\$/Bbl)	\$ 57.46	\$ 54.70	\$ 59.44
NYMEX WTI Crude Purchased Calls:			
Notional volume (Bbl)	2,850,000	750,000	216,000
Weighted average strike price (\$/Bbl)	\$ 58.41	\$ 61.32	\$ 69.58
Total Amounts Received/(Paid) from Settlement (in thousands)	\$ (123,518)	\$ (18,031)	\$ 34,196
Cash provided by (used in) changes in Accounts Receivable and Accounts Payable related to Commodity Derivatives	\$ (11,106)	\$ 6,046	\$ 8,631
Cash Settlements on Commodity Derivatives per Consolidated Statements of Cash Flows	\$ (134,624)	\$ (11,985)	\$ 42,827

Lease Operating Expenses

All direct and allocated indirect costs of lifting hydrocarbons from a producing formation to the surface constituting part of the current operating expenses of a working interest. Such costs include labor, superintendence, supplies, repairs, maintenance, 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 year ended December 31, 2018, we incurred approximately \$776.1 million in capital expenditures, excluding outstanding elections, in drilling 161 gross (129.7 net) wells with an average lateral length of 1.8 miles and completing 161 gross (137.4 net) wells with an average lateral length of 1.7 miles. In addition, we incurred approximately \$116.4 million of leasehold and surface acreage additions, excluding acquisitions. These capital expenditures exclude the impact of the decrease in outstanding elections of \$6.7 million. In addition, Elevation, our wholly owned midstream subsidiary, incurred \$108.2

million of capital expenditures for the year ended December 31, 2018. Our 2018 revised capital budget allocated approximately \$770 million to \$840 million to the drilling of 168 to 173 gross operated wells, completion of between 170 to 175 gross operated wells and turned to sales between 163 to 168 gross operated wells. Approximately \$120 million to \$150 million was allocated to acreage leasing, midstream and other capital expenditures, excluding amounts that were paid for acquisitions.

Our 2019 capital budget for the drilling and completion of operated and non-operated wells is approximately \$585.0 million to \$675.0 million, substantially all of which we intend to allocate to the Core DJ Basin. We expect to drill 125 gross operated wells, complete 122 gross operated wells and turn-in-line 111 gross operated wells. Our capital budget 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 and goodwill, exploration expenses, rig termination fees, write off of deposit on acquisition, (gain) loss on sale of property and equipment, gain on sale of assets of unconsolidated subsidiaries, acquisition transaction expenses, (gain) loss on commodity derivatives, settlements on commodity derivative instruments, premiums paid for derivatives that settled during the period, unit and stock-based compensation expense, amortization of debt discount and debt issuance costs, make-whole premiums, interest expense, income tax expense (benefit) and non-recurring charges. Adjusted EBITDAX is also used to evaluate the performance of reportable segments. See *Note 15 — Segment Information* in Item 8 in this Annual 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:

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

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

	For the Year Ended		
	December 31,		
	2018	2017	2016
Reconciliation of Net Income (Loss) to Adjusted EBITDAX:			
Net Income (Loss)	\$ 121,855	\$ (44,408)	\$ (456,001)
Add back:			
Depletion, depreciation, amortization and accretion	435,775	314,999	205,348
Impairment of long lived assets and goodwill	70,928	1,647	23,425
Exploration expenses	31,611	36,256	36,422
Rig termination fee	—	—	891
Write-off of deposit on acquisition	—	—	10,000
(Gain) loss on sale of property and equipment	(53,222)	451	—
(Gain) on sale of assets of unconsolidated subsidiary	(83,612)	—	—
Acquisition transaction expenses	—	—	2,719
(Gain) loss on commodity derivatives	8,554	36,332	100,947
Settlements on commodity derivative instruments	(123,518)	(18,031)	34,196
Premiums paid for derivatives that settled during the period	(7,148)	(580)	(5,553)
Stock-based compensation expense	68,349	65,607	200,308
Amortization of debt discount and debt issuance costs	13,249	4,260	19,256
Make-whole premium on 2021 Senior Notes	35,600	—	—
Interest expense	74,481	47,629	49,587
Income tax expense (benefit)	66,850	(63,700)	(29,280)
Adjusted EBITDAX	\$ 659,752	\$ 380,462	\$ 192,265

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:

- For the year ended December 31, 2018, we recognized \$136.8 million gain on sale of property and equipment and assets of unconsolidated subsidiary related to our April 2018 Divestitures, August 2018 Divestiture and December 2018 Divestitures. We also recognized \$54.2 million in impairment of goodwill resulting from the conclusion that the fair value of the reporting unit was not greater than its carrying amount and \$16.2 million related to impairment of the proved oil and gas properties in our northern field.
- On December 22, 2017, the TCJA was enacted making significant changes to the Internal Revenue Code. Many of the provisions in the TCJA have an effective date for years beginning after December 31, 2017, including the lowering of the U.S. corporate rate from 35% to 21%. As a result of the enactment date of December 22, 2017, we were required to remeasure the deferred tax assets and liabilities at the rate in which they are expected to reverse. We provisionally recorded an income tax benefit in the amount of \$23.4 million related to the remeasurement of the net deferred tax liability as of December 31, 2017. During the third quarter of 2018, we completed the accounting for the income tax effect of the TCJA's limit on compensation under Internal Revenue Code Sec. 162(m) and stock-based compensation for covered employees. This resulted in a \$0.4 million reduction in deferred tax assets that had been recorded as a provisional amount as of December 31, 2017. There are no remaining provision amounts associated with the TCJA as of December 31, 2018.
- In connection with the consummation of the IPO, we issued 185,280 shares of our Series A Preferred Stock to the holders of Holdings' Series B Preferred Units in conversion of such units. 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 paid in cash).

- We incur additional general and administrative expenses related to being a public company, including Exchange Act reporting expenses; expenses associated with Sarbanes-Oxley Act compliance; expenses associated with listing on the NASDAQ Global Select Market; incremental independent auditor fees; incremental legal fees; investor relations expenses; registrar and transfer agent fees; incremental director and officer liability insurance costs; and directors compensation.
- Prior to our initial public offering, we were not subject to federal or state income taxes. Accordingly, the financial data attributable to us prior to such corporate reorganization contain no provision for federal or state income taxes because the tax liability with respect to Holdings' taxable income was passed through to its members. Beginning October 12, 2016, we began to be taxed as a C corporation under the Code and subject to federal and state income taxes at a blended statutory rate of approximately 38% of pretax earnings. As a result of the TCJA, we were subject to federal and state income taxes at a blended statutory rate of approximately 24.7% of pretax earnings for the years ended December 31, 2018 and 2017.
- In October 2016, our board of directors adopted the Extraction Oil & Gas, Inc. 2016 Long Term Incentive Plan ("LTIP") and subsequently granted awards to certain directors, officers and employees, including stock options, restricted stock units and performance stock awards. We recognized \$48.7 million, \$48.3 million and \$8.5 million of stock-based compensation expense for years ended December 31, 2018, 2017 and 2016, respectively, related to these awards.
- On October 3, 2016, we acquired additional oil and gas properties primarily located in the Wattenberg Field located primarily around our existing Greeley and Windsor areas. The October 2016 Acquisition consisted of working interest in approximately 6,400 net acres and 31 gross (19 net) drilled but uncompleted wells, as of the date of acquisition. The October 2016 Acquisition provided net daily production of approximately 6,900 BOE/d during the fourth quarter of 2016.
- In 2015, we granted certain members of management incentive units pursuant to Holdings' 2014 Membership Unit Incentive Plan and its limited liability company agreement. These equity-based awards were subject to time-based vesting requirements, as well as accelerated vesting upon the occurrence of a change of control. In connection with the IPO, the Board of Managers of Holdings accelerated the vesting of the Holdings' Incentive Units. Our IPO and change of control triggered the conversion of these units into approximately 9.1 million of our common shares based on the 10-day volume weighted average price of our common stock following its IPO as set forth in the 2014 Plan and the Holdings LLC Agreement. For the year ended December 31, 2016, we recognized approximately \$172.1 million in non-cash, unit-based compensation expense in connection with the conversion of the Holdings' Incentive Units into our common stock.

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 Year Ended		
	December 31,		
	2018	2017	2016
Revenues:			
Oil sales	\$ 840,687	\$ 419,904	\$ 194,059
Natural gas sales	105,629	92,322	48,652
NGL sales	114,427	92,070	35,378
Total Revenues	1,060,743	604,296	278,089
Operating Expenses:			
Lease operating expenses	79,413	60,358	36,743
Transportation and gathering	39,411	50,948	25,300
Production taxes	90,345	51,367	20,730
Exploration expenses	31,611	36,256	36,422
Depletion, depreciation, amortization and accretion	435,775	314,999	205,348
Impairment of long lived assets and goodwill	70,928	1,647	23,425
Other operating expenses	—	—	10,891
(Gain) loss on sale of property and equipment and assets of unconsolidated subsidiary	(136,834)	451	—
Acquisition transaction expenses	—	—	2,719
General and administrative expenses	134,604	110,167	232,388
Total Operating Expenses	745,253	626,193	593,966
Operating Income (Loss)	315,490	(21,897)	(315,877)
Other Income (Expense):			
Commodity derivatives loss	(8,554)	(36,332)	(100,947)
Interest expense	(123,330)	(51,889)	(68,843)
Other income	5,099	2,010	386
Total Other Income (Expense)	(126,785)	(86,211)	(169,404)
Income (Loss) Before Income Taxes	188,705	(108,108)	(485,281)
Income tax (expense) benefit	(66,850)	63,700	29,280
Net Income (Loss)	\$ 121,855	\$ (44,408)	\$ (456,001)

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 Year Ended		
	December 31,		
	2018	2017	2016
Sales (MBoe)⁽¹⁾:	27,747	18,894	10,940
Oil sales (MBbl)	14,679	9,594	5,287
Natural gas sales (MMcf)	46,847	32,395	20,212
NGL sales (MBbl)	5,260	3,901	2,284
Sales (BOE/d)⁽¹⁾:	76,019	51,764	29,891
Oil sales (Bbl/d)	40,217	26,284	14,446
Natural gas sales (Mcf/d)	128,347	88,754	55,223
NGL sales (Bbl/d)	14,411	10,687	6,240
Average sales prices⁽²⁾:			
Oil sales (per Bbl)	\$ 57.27	\$ 43.77	\$ 36.70
Oil sales with derivative settlements (per Bbl)	48.04	41.67	40.59
Natural gas sales (per Mcf) ⁽³⁾	2.25	2.85	2.41
Natural gas sales with derivative settlements (per Mcf) ⁽³⁾	2.36	2.90	2.81
NGL sales (per Bbl) ⁽³⁾	21.75	23.60	15.49
Average price per BOE ⁽³⁾	38.23	31.98	25.42
Average price per BOE with derivative settlements ⁽³⁾	33.52	31.00	28.04
Expense per BOE⁽¹⁾:			
Lease operating expenses	\$ 2.86	\$ 3.19	\$ 3.36
Transportation and gathering ⁽³⁾	1.42	2.70	2.31
Production taxes	3.26	2.72	1.89
Exploration expenses	1.14	1.92	3.33
Depletion, depreciation, amortization, and accretion	15.71	16.67	18.77
Impairment of long lived assets and goodwill	2.56	0.09	2.14
General and administrative expenses	4.85	5.83	21.24
Cash general and administrative expenses	2.39	2.36	2.93
Unit and stock-based compensation	2.46	3.47	18.31
Total operating expenses per BOE ⁽⁴⁾	31.80	33.12	53.04
Production taxes as a percentage of revenue	8.5%	8.5%	7.5%

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- (1) One BOE is equal to six Mcf of natural gas or one Bbl of oil or NGL based on an approximate energy equivalency. This is an energy content correlation and does not reflect a value or price relationship between the commodities.
- (2) Average prices shown in the table reflect prices both before and after the effects of our settlements of our commodity derivative contracts. Our calculation of such effects includes both gains and losses on cash settlements for commodity derivatives and premiums paid or received on options that settled during the period.
- (3) As a result of the adoption of ASC 606 on January 1, 2018, certain costs previously classified as transportation and gathering expenses are presented on a net basis for proceeds expected to be received. See below for further information.
- (4) Excludes (gain) loss on sale of property and equipment, gain on sale of assets of unconsolidated subsidiary, other operating expenses and acquisition transaction expenses.

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

Oil sales revenues. Crude oil sales revenues increased by \$420.8 million to \$840.7 million for the year ended December 31, 2018 as compared to crude oil sales of \$419.9 million for the year ended December 31, 2017. An increase in sales volumes between these periods contributed to a \$222.6 million positive impact, while an increase in crude oil prices contributed a \$198.2 million positive impact.

For the year ended December 31, 2018, our crude oil sales averaged 40.2 MBbl/d. Our crude oil sales volumes increased 53% to 14,679 MBbl for the year ended December 31, 2018 compared to 9,594 MBbl for the year ended December 31, 2017. The volume increase was primarily due to an increase in production from the completion of 161 wells for the year ended December 31, 2018. The increased production from these new wells was partially offset by the natural decline of our existing producing properties.

The average price we realized on the sale of crude oil was \$57.27 per Bbl for the year ended December 31, 2018 compared to \$43.77 per Bbl for the year ended December 31, 2017.

Natural gas sales revenues. Natural gas sales revenues increased by \$13.3 million to \$105.6 million for the year ended December 31, 2018 as compared to natural gas sales revenues of \$92.3 million for the year ended December 31, 2017. An increase in sales volumes between these periods contributed a \$41.2 million positive impact, while a decrease in natural gas prices contributed a \$27.9 million negative impact. The decrease in pricing is partially attributable to our adoption of ASC 606. Adoption of this new standard was applied to all new contracts entered into on or after January 1, 2018 and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance. Amounts previously recognized as transportation and gathering ("T&G") under ASC 605 of \$15.6 million are currently recognized within natural gas sales revenues.

For the year ended December 31, 2018, our natural gas sales averaged 128.3 MMcf/d. Natural gas sales volumes increased by 45% to 46,847 MMcf for the year ended December 31, 2018 as compared to 32,395 MMcf for the year ended December 31, 2017. The volume increase was primarily due to the completion of 161 gross wells for the year ended December 31, 2018, partially offset by the natural decline on existing producing properties.

The average price we realized on the sale of our natural gas was \$2.25 per Mcf for the year ended December 31, 2018 compared to \$2.85 per Mcf for the year ended December 31, 2017.

NGL sales revenues. NGL sales revenues increased by \$22.3 million to \$114.4 million for the year ended December 31, 2018 as compared to NGL sales revenues of \$92.1 million for the year ended December 31, 2017. An increase in sales volumes between these periods contributed a \$32.0 million positive impact, while a decrease in price contributed a \$9.7 million negative impact. The decrease in pricing is partially attributable to our adoption of ASC 606. Adoption of this new standard was applied to all new contracts entered into on or after January 1, 2018 and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance. Amounts previously recognized as T&G under ASC 605 of \$20.1 million are currently recognized within NGL sales revenues.

For the year ended December 31, 2018, our NGL sales averaged 14.4 MBbl/d. NGL sales volumes increased by 36% to 5,260 MBbl for the year ended December 31, 2018 as compared to 3,901 MBbl for the year ended December 31, 2017. The volume increase is primarily due to the completion of 161 gross wells for the year ended December 31, 2018, partially offset by the natural decline on existing producing properties. Our NGL sales are directly associated with our natural gas sales because our natural gas volumes are processed by third parties for both residue natural gas sales and NGL sales.

The average price we realized on the sale of our NGL was \$21.75 per Bbl for the year ended December 31, 2018 compared to \$23.60 per Bbl for the year ended December 31, 2017.

Lease operating expenses ("LOE"). Our LOE, increased by \$19.0 million to \$79.4 million for the year ended December 31, 2018, from \$60.4 million for the year ended December 31, 2017. The increase in LOE was primarily the result of an increase in producing wells and an increase in equipment rental and other service rates, partially offset by optimization of our field cost structure for the year ended December 31, 2018.

On a per unit basis, LOE decreased to \$2.86 per BOE sold for the year ended December 31, 2018 from \$3.19 per BOE sold for the year ended December 31, 2017. The decrease in LOE per BOE is primarily a result of flush production on several new pads turned-in-line for the year ended December 31, 2018.

Transportation and gathering. Our T&G expense decreased by \$11.5 million to \$39.4 million for the year ended December 31, 2018, from \$50.9 million for the year ended December 31, 2017. The decrease in T&G is primarily attributable to adoption of ASC 606. Adoption of this new standard was applied to all new contracts entered into on or after January 1, 2018 and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance. Amounts previously recognized as T&G under ASC 605 of \$35.7 million are currently recognized within natural gas and NGL sales revenues. This decrease was offset by an increase in producing wells and in both residue natural gas and NGL sales volumes, resulting in \$24.2 million of collectively higher T&G.

On a per unit basis, T&G decreased to \$1.42 per BOE sold for the year ended December 31, 2018 from \$2.70 per BOE sold for the year ended December 31, 2017. The decrease in T&G per BOE is primarily the result of the adoption of ASC 606.

Production taxes. Our production taxes increased by \$38.9 million to \$90.3 million for the year ended December 31, 2018 as compared to \$51.4 million for the year ended December 31, 2017. The increase was attributable to increased revenue as production taxes are calculated as a percentage of sales revenue. Production taxes as a percentage of sales revenue was 8.5% for the year ended December 31, 2018 as compared to 8.5% for the year ended December 31, 2017. Production taxes were consistent for the years ended December 31, 2018 and 2017.

Exploration expenses. Our exploration expenses were \$31.6 million and \$36.3 million for the years ended December 31, 2018 and 2017, respectively. We recognized \$4.6 million in expense attributable to the extension of certain leases and \$25.7 million in expense attributable to the abandonment and impairment of unproved properties for the year ended December 31, 2018. We recognized \$18.7 million in expense attributable to the extension of certain leases and \$15.8 million in expense attributable to the abandonment and impairment of unproved properties for the year ended December 31, 2017.

Depletion, depreciation, amortization and accretion expense. Our DD&A expense increased \$120.8 million to \$435.8 million for the year ended December 31, 2018 as compared to \$315.0 million for the year ended December 31, 2017. This increase was due to increased volumes sold for the year ended December 31, 2018 as sales increased by approximately 8,853 MBoe. On a per unit basis, DD&A expense decreased from \$16.67 per BOE for the year ended December 31, 2017 to \$15.71 per BOE for the year ended December 31, 2018. The decrease in DD&A per BOE is due to an increase in reserves related to an increase in prices and extensions, slightly offset by increased production for the year ended December 31, 2018.

Impairment of long lived assets and goodwill. For the year ended December 31, 2018, our impairment expense was \$70.9 million. We recognized \$16.2 million related to impairment of the proved oil and gas properties in our northern field. The fair value did not exceed the Company's carrying amount associated with its proved oil and gas properties in its northern field. Impairment on goodwill of \$54.2 million was recognized upon completion of a quantitative assessment noting the fair value of the reporting unit was not greater than its carrying amount. For the year ended December 31, 2017, we recognized \$1.6 million associated with impairment on other property and equipment and certain well equipment inventory evaluated to have a net realizable value less than the carrying value, as the equipment was determined to no longer be useful in our current drilling operations.

(Gain) loss on sale of property and equipment and assets of unconsolidated subsidiary. Our gain on sale of property and equipment and assets of unconsolidated subsidiary was \$136.8 million for the year ended December 31, 2018, which was related to our April 2018 Divestitures, August 2018 Divestiture and December 2018 Divestitures, as compared to \$0.5 million loss on the sale of property and equipment for the year ended December 31, 2017.

General and administrative expenses ("G&A"). General and administrative expenses increased by \$24.4 million to \$134.6 million for the year ended December 31, 2018 as compared to \$110.2 million for the year ended December 31, 2017. This increase was primarily due to an increase in our employee head count for the year ended December 31, 2018 compared to the year ended December 31, 2017. On a per unit basis, G&A expenses decreased by \$0.98 per BOE from \$5.83 per BOE sold for the year ended December 31, 2017 to \$4.85 per BOE sold for the year ended December 31, 2018.

Our G&A expenses includes the non-cash expense for stock-based compensation for equity awards granted to our employees and directors. For the year ended December 31, 2018, stock-based compensation expense was \$68.3 million as compared to stock-based compensation expense of \$65.6 million for the year ended December 31, 2017. On a per unit basis, stock-based compensation decreased \$1.01 per BOE from \$3.47 per BOE sold for the year ended December 31, 2017 to \$2.46 per BOE sold for the year ended December 31, 2018.

Our other G&A expenses increased by \$21.7 million during the year ended December 31, 2018 compared to the year ended December 31, 2017, primarily due to the growth of the Company, including an increase in employed workforce of 23%, or 52 additional employees. On a per BOE basis, other G&A expenses per BOE sold increased \$0.03 per BOE sold from \$2.36 per BOE sold for the year ended December 31, 2017 to \$2.39 per BOE sold for the year ended December 31, 2018. The increase in other G&A expenses on a per BOE basis is partially offset by increased sales volumes for the year ended December 31, 2018.

Commodity derivative loss. Primarily due to the change in fair value from the execution of new positions during the year ended December 31, 2018, partially offset by a decrease in NYMEX crude oil futures prices at December 31, 2018 as compared to December 31, 2017, we incurred a net loss on our commodity derivatives of \$8.6 million and \$36.3 million for the years ended December 31, 2018 and 2017, respectively. 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. For the year ended December 31, 2018 and 2017, we paid cash settlements of commodity derivatives totaling \$123.5 million and \$18.0 million, respectively.

Interest expense. Interest expense consists of interest expense on our long-term debt and debt issuance costs, net of capitalized interest. For the year ended December 31, 2018, we recognized interest expense of approximately \$123.3 million as compared to \$51.9 million for the year ended December 31, 2017, as a result of borrowings under our revolving credit facility, our 2021 Senior Notes and the associated make-whole premium and accelerated amortization of debt issuance costs upon redemption, our 2024 Senior Notes, our 2026 Senior Notes, and the amortization of other debt issuance costs.

We incurred interest expense for the year ended December 31, 2018 of approximately \$82.7 million related to our 2021 Senior Notes, 2024 Senior Notes, 2026 Senior Notes and credit facility, as well as a make-whole premium of \$35.6 million related to our repayment of our 2021 Senior Notes in January and February 2018. We incurred interest expense for the year ended December 31, 2017 of approximately \$58.7 million related to our credit facility, 2021 Senior Notes and 2024 Senior Notes. Also included in interest expense for the years ended December 31, 2018 and 2017 was the amortization of debt issuance costs of \$13.2 million and \$4.3 million, respectively. Amortization expense for the year ended December 31, 2018 includes \$9.4 million of acceleration of amortization expense upon the repayment of our 2021 Senior Notes. For the years ended December 31, 2018 and 2017, we capitalized interest expense of \$8.2 million and \$11.1 million, respectively.

Income tax (expense) benefit. We recorded income tax expense of approximately \$66.9 million and income tax benefit of \$63.7 million resulting in an effective tax rate of approximately 35.4% and 58.9% for the years ended December 31, 2018 and 2017, respectively. Our effective tax rate for 2018 differs from the U.S. statutory income tax rate of 24.7% primarily due to the effects of state income taxes, estimated permanent taxable differences, including the book impairment of goodwill and partnership income allocated to a noncontrolling interest owner.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Oil sales revenues. Crude oil sales revenues increased by \$225.8 million to \$419.9 million for the year ended December 31, 2017 as compared to crude oil sales of \$194.1 million for the year ended December 31, 2016. An increase in sales volumes between these periods contributed to a \$158.0 million positive impact, while an increase in crude oil prices contributed a \$67.8 million positive impact.

For the year ended December 31, 2017, our crude oil sales averaged 26.3 MBbl/d. Our crude oil sales volumes increased 81% to 9,594 MBbl in the year ended December 31, 2017 compared to 5,287 MBbl for the year ended December 31, 2016. The volume increase was primarily due to the development of our properties. For the year ended December 31, 2017, we completed 198 gross wells. The increased production from these new wells was offset by the normal decline on the existing producing properties.

The average price we realized on the sale of crude oil was \$43.77 per Bbl for the year ended December 31, 2017 compared to \$36.70 per Bbl for the year ended December 31, 2016.

Natural gas sales revenues. Natural gas sales revenues increased by \$43.6 million to \$92.3 million for the year ended December 31, 2017 as compared to natural gas sales revenues of \$48.7 million for the year ended December 31, 2016. An increase in sales volumes between these periods contributed a \$29.3 million positive impact, while an increase in natural gas prices contributed a \$14.3 million positive impact.

For the year ended December 31, 2017, our natural gas sales averaged 88.8 MMcf/d. Natural gas sales volumes increased by 60% to 32,395 MMcf for the year ended December 31, 2017 as compared to 20,212 MMcf for the year ended December 31, 2016. The volume increase was primarily due to the development of our properties. For the year ended December 31, 2017, we completed 198 gross wells. The increased production from these new wells was offset by the normal decline on the existing producing properties.

The average price we realized on the sale of our natural gas was \$2.85 per Mcf for the year ended December 31, 2017 compared to \$2.41 per Mcf for the year ended December 31, 2016.

NGL sales revenues. NGL revenues increased by \$56.7 million to \$92.1 million for the year ended December 31, 2017 as compared to NGL revenues of \$35.4 million for the year ended December 31, 2016. An increase in sales volumes between these periods contributed a \$25.0 million positive impact, while an increase in price contributed a \$31.7 million positive impact.

For the year ended December 31, 2017, our NGL sales averaged 10.7 MBbl/d. NGL sales volumes increased by 70% to 3,901 MBbl for the year ended December 31, 2017 as compared to 2,284 MBbl for the year ended December 31, 2016. The volume increase was due to the development of our properties. Our NGL sales are directly associated with our natural gas sales since the majority of our natural gas volumes are processed by third parties which return a percentage of the proceeds from both residue natural gas sales and NGL sales.

The average price we realized on the sale of our NGL was \$23.60 per Bbl for the year ended December 31, 2017 compared to \$15.49 per Bbl for the year ended December 31, 2016.

Lease operating expenses. Our LOE, increased by \$23.7 million to \$60.4 million for the year ended December 31, 2017, from \$36.7 million for the year ended December 31, 2016. The increase in LOE was due to the development of our properties. For the year ended December 31, 2017, we completed 198 gross wells. On a per BOE basis there was a decrease in operating expenses of \$0.17 per BOE from \$3.36 per BOE for the year ended December 31, 2016 to \$3.19 per BOE for the year ended December 31, 2017. The decrease in LOE per BOE was primarily a result of flush production on several new pads turn-in-line during the year ended December 31, 2017.

Transportation and gathering. Our T&G expense increased by \$25.6 million to \$50.9 million for the year ended December 31, 2017, from \$25.3 million for the year ended December 31, 2016. On a per unit basis, there was an increase in T&G expense of \$0.39 per BOE from \$2.31 per BOE for the year ended December 31, 2016 to \$2.70 per BOE for the year ended December 31, 2017. These increases were due to the increase in producing wells and in both residue natural gas and NGL sales volumes and realized prices.

Production taxes. Our production taxes increased by \$30.7 million to \$51.4 million for the year ended December 31, 2017 as compared to \$20.7 million for the year ended December 31, 2016. The increase was attributable to increased revenue as State of Colorado production taxes are calculated as a percentage of sales revenue. Production taxes as a percentage of sales revenue was 8.5% for the year ended December 31, 2017 as compared to 7.5% for the year ended December 31, 2016. The increase in production taxes as a percentage of sales revenue relates to an increase in the estimated ad valorem and severance tax rates for the year ended December 31, 2017.

Exploration expenses. Our exploration expenses were \$36.3 million and \$36.4 million for the years ended December 31, 2017 and 2016, respectively. We recognized \$18.7 million in expense attributable to the extension of leases, \$15.8 million in expense attributable to the abandonment and impairment of unproved properties and \$1.4 million of costs associated with exploratory geological and geophysical costs for the year ended December 31, 2017. We recognized \$14.1 million in expense attributable to the extension of leases and \$22.3 million in expense attributable to the abandonment and impairment of unproved properties for the year ended December 31, 2016.

Depletion, depreciation, amortization and accretion expense. Our DD&A expense increased \$109.7 million to \$315.0 million for the year ended December 31, 2017 as compared to \$205.3 million for the year ended December 31, 2016. This increase was due to higher volumes sold for the year ended December 31, 2017 as sales increased by approximately 7,954 MBoe. On a per unit basis, DD&A expense decreased from \$18.77 per BOE for the year ended December 31, 2016 to \$16.67 per BOE for the year ended December 31, 2017. The decrease in DD&A per BOE is due to an increase in reserves related to an increase in prices and extensions, slightly offset by increased production for the year ended December 31, 2017.

Impairment of long lived assets. For the year ended December 31, 2017, our impairment expense was \$1.6 million, associated with impairment on other property and equipment and certain well equipment inventory evaluated to have a net

realizable value less than the carrying value, as the equipment was determined to no longer be useful in our current drilling operations. For the year ended December 31, 2016, we recognized \$22.5 million in impairment expense on proved oil and gas properties in our northern field. The future undiscounted cash flows did not exceed its carrying amount associated with its proved oil and gas properties in our northern field and it was determined that the proved oil and gas properties had no remaining fair value. Therefore, the full net book value of these proved oil and gas properties were impaired at June 30, 2016. Additionally, for the year ended December 31, 2016 we recognized \$0.9 million of impairment on other property and equipment.

Loss on sale of property and equipment. Loss on sale of property and equipment for the for the year ended December 31, 2017 is comprised of a \$0.5 million loss on the sale of property and equipment. There were no such losses on the sale of property and equipment for the year ended December 31, 2016.

Other operating expenses. Other operating expenses for the year ended December 31, 2016 includes \$10.0 million on the write off of a non-refundable payment related to an option to acquire additional acreage. In March 2017, we entered into an amendment to this agreement with seller to terminate both our and the seller's options for no further consideration. Also included in other operating expenses for the year ended December 31, 2016 is a \$0.9 million rig termination fee related to the early termination of a rig in February 2016. There were no such expenses for the year ended December 31, 2017.

Acquisition transaction expenses. There were no significant acquisition transaction expenses for the year ended December 31, 2017. As part of the acquisition of properties in August 2016 and October 2016, we incurred \$2.7 million of transaction costs associated with a finder's fee, legal expenses and due diligence for the year ended December 31, 2016.

General and administrative expenses. General and administrative expenses decreased by \$122.2 million to \$110.2 million for the year ended December 31, 2017 as compared to \$232.4 million for the year ended December 31, 2016. This decrease was comprised of a decrease in unit and stock-based compensation of \$134.7 million, offset by an increase in other general and administrative expenses of \$12.5 million. On a per unit basis, G&A expenses decreased from \$21.24 per BOE sold for the year ended December 31, 2016 to \$5.83 per BOE sold for the year ended December 31, 2017.

Our G&A expenses includes the non-cash expense for unit and stock-based compensation for equity awards granted to our employees, directors, officers and non-employee consultants. For the year ended December 31, 2017, stock-based compensation expense was \$65.6 million as compared to unit and stock-based compensation expense of \$200.3 million for the year ended December 31, 2016. On a per unit basis, unit and stock-based compensation decreased \$14.84 per BOE from \$18.31 per BOE sold for the year ended December 31, 2016 to \$3.47 per BOE sold for the year ended December 31, 2017. The decrease in unit and stock-based compensation expense was due to accelerated vesting of outstanding Holdings RUAs in connection with our Corporate Reorganization and IPO in 2016. Additionally, as a result of the IPO in 2016, Holdings incentive units were converted to common stock resulting in the recognition of \$172.1 million of stock-based compensation expense. Also in 2016, we created a Long Term Incentive Plan, which resulted in the granting of RSUs, stock options and performance stock awards to certain board members, officers, and employees.

Our other G&A expenses increased by \$12.5 million during the year ended December 31, 2017 compared to the year ended December 31, 2016, primarily due to the growth of the Company, including an increase in employed workforce of 41.0%, or 66 additional employees. However, on a per BOE basis, other G&A expenses per BOE sold decreased \$0.57 per BOE sold from \$2.93 per BOE sold for the year ended December 31, 2016 to \$2.36 per BOE sold for the year ended December 31, 2017. The decrease in other G&A expenses on a per BOE basis is due to higher production volumes for the year ended December 31, 2017.

Commodity derivative gain (loss). Primarily due to the increase in NYMEX crude oil futures prices at December 31, 2017 as compared to December 31, 2016 and change in fair value from the execution of new positions during each period, we incurred a net loss on our commodity derivatives of \$36.3 million and \$100.9 million for the years ended December 31, 2017 and 2016, respectively. 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. 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. For the year ended December 31, 2017, we paid cash settlements of commodity derivatives totaling \$18.0 million. For the year ended December 31, 2016, we received cash settlements of commodity derivatives totaling \$34.2 million.

Interest expense. Interest expense consists of interest paid and accrued on our long term debt, amortization of debt discount and debt issuance costs, net of capitalized interest. For the year ended December 31, 2017, we recognized interest expense of approximately \$51.9 million as compared to \$68.8 million for the year ended December 31, 2016, as a result of

borrowings under our revolving credit facility, our Second Lien Notes in 2016, our 2021 Senior Notes, our 2024 Senior Notes in 2017 and the amortization of debt issuance costs and debt discount.

We incurred interest expense for the year ended December 31, 2017 of approximately \$58.7 million related to our 2024 Senior Notes, 2021 Senior Notes and credit facility. We incurred interest expense for the year ended December 31, 2016 of approximately \$50.4 million related to our Second Lien Notes, our 2021 Senior Notes and credit facility. Also included in interest expense for the years ended December 31, 2017 and 2016 was the amortization of debt issuance costs and debt discount of \$4.3 million and \$4.2 million, respectively. For the years ended December 31, 2017 and 2016, we capitalized interest expense of \$11.1 million and \$5.2 million, respectively. Also included in interest expense for the year ended December 31, 2016 is a prepayment penalty of \$4.3 million and the accelerated amortization of our remaining unamortized debt discount and debt issuance costs of \$15.1 million related to our repayment of the Second Lien Notes in July 2016.

Income tax benefit. We recorded an income tax benefit of approximately \$63.7 million and \$29.3 million resulting in an effective tax rate of approximately 58.9% and 6.0% for the years ended December 31, 2017 and 2016, respectively. Our effective tax rate for 2017 differs from the U.S. statutory income tax rate of 38.0% primarily due to the effects of state income taxes, estimated permanent taxable differences and a one-time remeasurement of net deferred tax liabilities from 38.0% to 24.7% due to the Tax Cuts and Jobs Act. During the year ended December 31, 2017, our income tax benefit increased \$34.4 million compared to the same period in 2016, which was primarily due to the one-time remeasurement of net deferred tax liabilities in 2017 and our corporate reorganization to a C-Corp in 2016. Excluding the impact of the one-time remeasurement of net deferred tax liabilities required in 2017, our overall effective tax rate was 37.3% for the year ended December 31, 2017.

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, 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 \$1,417.7 million and \$1,023.4 million at December 31, 2018, and 2017, respectively. We also have other contractual commitments, which are described in *Note 13 — Commitments and Contingencies* in Item 8 of this Annual Report.

We plan to continue our practice of entering into hedging arrangements to reduce the impact of commodity price volatility on our cash flow from operations. Under this strategy, we intend to enter into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering approximately 50% to 70% of our projected oil and natural gas production over a one to two year period at a given point in time, although we may from time to time hedge more or less than this approximate range.

Based on current expectations, we believe we have sufficient liquidity through our existing cash balances, cash flow from operations and available borrowings under our revolving credit facility to execute our current capital program, excluding any acquisitions we may consummate, make our interest payments on the 2024 Senior Notes, 2026 Senior Notes and credit facility and pay dividends on our Series A Preferred Stock and the Elevation Preferred Units.

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

Our 2019 capital budget for the drilling and completion of operated and non-operated wells is approximately \$585.0 million to \$675.0 million, substantially all of which we intend to allocate to the Core DJ Basin. We expect to drill 125 gross operated wells, complete 122 gross operated wells and turn-in-line 111 gross operated wells. Our capital budget 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.

We currently have both a Stock Repurchase Program and a Senior Notes Repurchase Program in place. Spending under these programs in 2018 was \$26.2 million and we expect continued spending under these programs through the first quarter of 2019.

Cash Flows

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

	For the Year Ended December 31,		
	2018	2017	2016
Net cash provided by operating activities	\$ 684,933	\$ 316,965	\$ 120,688
Net cash used in investing activities	(897,305)	(1,404,528)	(873,608)
Net cash provided by financing activities	440,590	463,395	1,286,750

Year Ended December 31, 2018 Compared to the Year Ended December 31, 2017

Net cash provided by operating activities For the year ended December 31, 2018 as compared to the year ended December 31, 2017, our net cash provided by operating activities increased by \$368.0 million, primarily driven by an increase in sales volume of 8,853 MBoe and increase in realized price of \$6.25 per BOE resulting in an increase in net income of \$166.3 million. An increase in changes in current assets and liabilities of \$134.4 million also contributed to the increase in cash provided by operating activities.

Net cash used in investing activities. For the year ended December 31, 2018 as compared to the year ended December 31, 2017, our net cash used in investing activities decreased by \$507.2 million primarily due to a decrease of \$354.4 million used in oil and gas property additions, gathering systems and facilities additions, and other property and equipment additions. An increase of cash provided by the sale of assets of an unconsolidated subsidiary of \$83.6 million and the sale of property and equipment of \$75.7 million also contributed to the decrease in cash used in investing activities.

Net cash provided by financing activities. For the year ended December 31, 2018 as compared to the year ended December 31, 2017, our net cash provided by financing activities decreased by \$22.8 million, primarily as a result of cash used in the redemption of the 2021 Senior Notes for \$585.6 million, including a make-whole premium of \$35.6 million and \$28.6 million associated with repurchase of common shares. This decrease was offset by an increase of cash provided by the issuance of the Senior Notes of \$345.7 million, an increase of cash provided by the net borrowings under the credit facility of \$105.0 million, and an increase of cash provided by the issuance of Elevation Preferred Units of \$141.6 million.

Year Ended December 31, 2017 Compared to the Year Ended December 31, 2016

Net cash provided by operating activities For the year ended December 31, 2017 as compared to the year ended December 31, 2016, our net cash provided by operating activities increased by \$196.3 million, primarily driven by an increase in sales volume of 7,954 MBoe and increase in realized price of \$6.56 per BOE resulting in a reduction in net loss of \$411.6 million. An increase in deferred income tax benefit of \$34.4 million and increase in changes in current assets and liabilities of \$14.7 million also contributed to this increase. This increase was offset by a decrease of stock-based compensation of \$134.7 million and settlements on commodity derivatives of \$54.8 million.

Net cash used in investing activities. For the year ended December 31, 2017 as compared to the year ended December 31, 2016, our net cash used in investing activities increased by \$530.9 million primarily due to an increase of \$935.7 million in cash expended for drilling and completion activities and other property and equipment. This increase was offset by a decrease in acquired oil and gas properties of \$401.8 million.

Net cash provided by financing activities. For the year ended December 31, 2017 as compared to the year ended December 31, 2016, our net cash provided by financing activities decreased by \$823.4 million, primarily as a result of a decrease of \$1,243.1 million in proceeds from the issuance of common stock and members units, net of issuance costs, and a decrease of \$171.6 million in proceeds from the issuance of preferred units and stock in the year ended December 31, 2016. This decrease was offset by an increase of \$315.0 million in borrowings under the credit facility and an increase of \$278.3 million in net proceeds and repayments of 2021 Senior Notes, 2024 Senior Notes and Second Lien Notes.

Working Capital

Our working capital surplus (deficit) was \$62.2 million and \$(236.7) million at December 31, 2018 and 2017, respectively. Our cash balances totaled \$235.0 million and \$6.8 million at December 31, 2018 and 2017, respectively.

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

Debt Arrangements

Our revolving credit facility has a maximum credit amount of \$1.5 billion and a current borrowing base of \$1.2 billion, subject to the current maximum lending commitments of \$650.0 million. All of our current and future restricted subsidiaries will be guarantors under such facility, with the exception of Elevation. 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 5 — Long-Term Debt* in Item 8. Financial Statements and Supplementary Data of this Annual 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 unsecured 7.375% Senior Notes due 2024 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 commencing 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 and future restricted subsidiaries.

In January 2018, we closed a private offering of our unsecured 5.625% Senior Notes due 2026 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 and future restricted subsidiaries.

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 December 31, 2018, the borrowing base was \$1.2 billion, subject to current elected commitments of \$650.0 million, and we had \$285.0 million of borrowings outstanding under our revolving credit facility. In December 2018, we completed the November 1, 2018 borrowing base redetermination.

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 December 31, 2018, we had \$285.0 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 our and our restricted subsidiaries' (i) consolidated debt less cash balances to (ii) 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 matured on July 15, 2021.

Concurrent with the 2026 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 includes a make-whole premium of \$3.0 million and accrued and unpaid interest of approximately \$0.3 million.

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 paid 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 guarantees our indebtedness under a credit facility. The 2024 Senior Notes are effectively subordinated to all of our secured indebtedness (including all borrowings and other obligations under our revolving credit facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated in right of payment to all existing and future indebtedness and other liabilities (including trade payables) of any of our future subsidiaries that do not guarantee the 2024 Senior Notes.

2026 Senior Notes

On January 25, 2018, we closed a private offering of our 2026 Senior Notes that resulted in net proceeds of approximately \$737.9 million. Our 2026 Senior Notes bear interest at an annual rate of 5.625%. Interest on the 2026 Senior Notes is payable on February 1 and August 1 of each year, and the first interest payment was made on August 1, 2018. Our 2026 Senior Notes will mature on February 1, 2026. As of the date of this filing, we have repurchased 2026 Senior Notes with a nominal value of \$13.1 million for \$10.5 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 each 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.

Convertible Preferred Securities and Series A Preferred Stock

We previously issued investment funds managed by Apollo Global Management ("Apollo") \$75.0 million in Series A Preferred Units to fund a portion of the purchase price for the October 2016 Acquisition. The Series A Preferred Units were entitled to receive a cash dividend of 10% per year, payable quarterly in arrears. In 2016, we used \$90.0 million of the net proceeds from the IPO to redeem the Series A Preferred Units in full, which included a premium of \$15.0 million.

In addition, we issued to, among others, investment funds managed by OZ Management LP and Yorktown \$185.3 million in Series B Preferred Units to fund a portion of the purchase price for the October 2016 Acquisition. The Series B Preferred Units were entitled to receive a cash dividend of 10% per year, payable quarterly in arrears, and we had the ability to pay up to 50% of the quarterly dividend in kind. The Series B Preferred Units were converted in connection with the closing of the IPO into shares of our Series A Preferred Stock that 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. In certain situations, including a change of control, the Series A Preferred Stock may be redeemed for cash in an amount equal to the greater of (i) 135% of the liquidation preference of the Series A Preferred Stock and (ii) a 17.5% annualized internal rate of return on the liquidation preference of the Series A Preferred Stock. The Series A Preferred Stock mature on October 15, 2021, at which time they are mandatorily redeemable for cash at the liquidation preference. See *Note 9 — Equity— Series A Preferred Stock and Series B Preferred Units*” in Item 8. Financial Statements and Supplementary Data of this Annual Report.

Elevation Preferred Units

On July 3, 2018, Elevation Midstream, LLC (“Elevation”), a Delaware limited liability company and subsidiary of the Company, 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 to Extraction 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 consolidated balance sheets, consolidated statements of operations and consolidated statements of changes in members' and stockholders' equity and noncontrolling interest. 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 December 31, 2018, \$136.9 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 Preferred Unit Commitment Period, subject to the satisfaction of certain financial and operational metrics and certain other customary closing conditions, Elevation has the right to require the Purchaser to purchase additional Elevation Preferred Units on the terms set forth in the Securities Purchase Agreement. Elevation may require the Purchaser to purchase additional Elevation Preferred Units, in increments of at least \$25.0 million, up to an aggregate amount of \$350.0 million. During the Preferred Unit Commitment Period, Elevation is required to pay the Purchaser a quarterly commitment fee payable in cash or in kind of 1.0% per annum on any undrawn amounts of such additional \$350.0 million commitment.

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

Commitments, Contingencies and Contractual Obligations

A summary of our commitments, contingencies and contractual obligations as of December 31, 2018 is provided in the following table (in thousands).

	Payments due by Period				
	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
Contractual Obligations					
Office leases ⁽¹⁾	\$ 32,758	\$ 3,512	\$ 6,757	\$ 6,770	\$ 15,719
Drilling rig obligations ⁽²⁾	9,201	9,201	—	—	—
Volume commitments ⁽³⁾⁽⁴⁾	875,828	105,605	221,701	224,806	323,716
Revolving credit facility and interest payable ⁽⁵⁾	294,864	2,429	4,858	287,577	—
Senior Notes and Interest Payable ⁽⁶⁾	1,613,197	71,340	142,123	142,123	1,257,611
Total	\$ 2,825,848	\$ 192,087	\$ 375,439	\$ 661,276	\$ 1,597,046

- (1) We lease two office spaces in Denver, Colorado, two office spaces in Greeley, Colorado and one office space in Houston, Texas under separate operating lease agreements. The Denver, Colorado leases expire on February 29, 2020 and May 31, 2028. The Greeley, Colorado and Houston, Texas leases expire on October 31, 2019, June 30, 2019 and January 31, 2022,

respectively. Total rental commitments under non-cancelable leases for office space were \$32.8 million at December 31, 2018.

- (2) As of December 31, 2018, we were subject to commitments on three drilling rigs. The three drilling rigs are under contract and are set to expire on February 19, 2019, May 26, 2019 and November 23, 2019.
- (3) As of December 31, 2018, our oil marketer is 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, we amended our agreement with our oil marketer that requires us to sell all of our crude oil from an area of mutual interest in exchange for a make-whole provision that allows us to satisfy any minimum volume commitment deficiencies incurred by our oil marketer with future barrels of crude oil in excess of their minimum volume commitment through October 31, 2018. In December 2017, we extended the term of this agreement through October 31, 2019 and posted a letter of credit in the amount of \$35.0 million. We are currently in the process of amending and extending this agreement. We evaluate our contracts for loss contingencies and accrues for such losses, if the loss can be reasonably estimated and deemed probable. We also have two long-term crude oil gathering commitments with an unconsolidated subsidiary, in which we have a minority ownership interest. The first agreement commenced in November 2016 and has a term of ten years with a minimum volume commitment of an average 9,167 Bbl/d in year one, 17,967 Bbl/d in year two, 18,800 Bbl/d for years three through five and 10,000 Bbl/d for years six through ten. The second agreement will commence in or around July 2019 and has a term of ten years for an average of 3,200 Bbl/d in year one, 8,000 Bbl/d in year two, 14,000 Bbl/d in year three, 16,000 Bbl/d in years four through eight, 12,000 Bbl/d in year nine and 10,000 Bbl/d in year ten. The remaining aggregate amount of estimated payments under these agreements is approximately \$875.8 million.
- (4) In collaboration with several other producers and a midstream provider, on December 15, 2016 and August 7, 2017, we agreed to participate in expansions of natural gas gathering and processing capacity in the DJ Basin. The plan includes two new processing plants as well as the expansion of related gathering systems. The first plant commenced operations in August 2018 and the second plant is expected to be completed by mid-2019, although the exact start-up date is undetermined at this time. Our share of these commitments will require 51.5 MMcf and 20.6 MMcf per day, respectively, to be delivered after the plants' in-service dates for a period of seven years thereafter. We may be required to pay a shortfall fee for any volumes under these commitments. These contractual obligations can be reduced by our 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. We are also required for the first three years of each contract to guarantee a certain target profit margin on these volumes sold. Under our current drilling plans, we expect to meet these volume commitments and they have therefore not been reflected in the table above.
- (5) Calculated based on balance of \$285.0 million outstanding borrowings under our revolving credit facility as of December 31, 2018 and assumes no borrowings until the maturity date of the facility. Interest on our revolving credit facility is payable at one of the following two variable rates as selected by us: a base rate based on the Prime Rate or the Eurodollar rate based in LIBOR. Either rate is adjusted upward by an applicable margin, based on the utilization percentage of the facility as outlined in the Pricing Grid. Additionally, our revolving credit facility provides for a commitment fee of 0.375% to 0.50%, depending on borrowing base usage.
- (6) Calculated based on the December 31, 2018 outstanding aggregate principal amount on our 2024 Senior Notes of \$400.0 million outstanding, at a fixed rate of 7.375%, and outstanding principal amount on our 2026 Senior Notes of \$750.0 million outstanding, at a fixed rate of 5.625%. Interest is payable on our 2024 Senior Notes and 2026 Senior Notes on a semi-annual basis through the maturity dates of May 15, 2024 and February 1, 2026, respectively.

The above contractual obligations schedule does not include the Series A Preferred Stock, future anticipated settlement of derivative contracts or estimated amounts expected to be incurred in the future associated with the abandonment of our oil and gas properties, as we cannot determine with accuracy the timing of such payments. Additionally, the above contractual obligations schedule does not include lease operating expenses or budgeted capital expenditures. For further discussion regarding our Series A Preferred Stock, derivative contracts and estimated future costs associated with the abandonment of our oil and gas properties, please refer to *Note 9 — Equity*, *Note 6 — Commodity Derivative Instruments* and *Note 7 — Asset Retirement Obligations* to our historical audited financial statements for the years ended December 31, 2018 and 2017. Additionally, for further information regarding our contractual obligations, lease operating expenses and budgeted capital expenditures as of December 31, 2018, please refer to *Note 13 — Commitments and Contingencies* to our historical unaudited financial statements, *"Historical Results of Operations and Operating Expenses"* for the year ended December 31, 2018 and 2017 and *"Capital Expenditures"* in Item 7 of this Annual Report.

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

Off-Balance Sheet Arrangements

As of December 31, 2018, we do not have material off-balance sheet arrangements, except for our agreement with our oil marketer. Our oil marketer is subject to a firm transportation agreement with a make-whole provision that allows us to satisfy any minimum volume commitment deficiencies incurred by our oil marketer with future barrels of crude oil in excess of their minimum volume commitment through October 31, 2019. We are currently in the process of amending and extending this agreement. Please see *Note 13 - Commitments and Contingencies* in Part II, Item 8 of this Annual Report.

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. 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.

Critical Accounting Policies and Estimates

Use of Estimates in the Preparation of Financial Statements

The preparation of the financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant areas requiring the use of assumptions, judgments and estimates include (1) oil and gas reserves; (2) cash flow estimates used in impairment testing of oil and gas properties and goodwill; (3) depreciation, depletion, amortization and accretion; (4) asset retirement obligations; (5) assigning fair value and allocating purchase price in connection with business combinations, including the determination of any resulting goodwill; (6) accrued revenue and related receivables; (7) valuation of commodity derivative instruments; (8) accrued liabilities; (9) valuation of unit and stock-based payments, and (10) income taxes. Although management believes these estimates are reasonable, actual results could differ from these estimates. We evaluate our estimates on an on-going basis and base our estimates on historical experience and on various other assumptions we believe to be reasonable under the circumstances. Although actual results may differ from these estimates under different assumptions or conditions, we believe our estimates are reasonable.

Successful Efforts Method of Accounting

We follow the successful efforts method of accounting for oil and gas properties. Under this method of accounting, all property acquisition costs and development costs are capitalized when incurred and depleted on a units-of-production basis over the remaining life of proved reserves and proved developed reserves, respectively.

The costs of exploratory wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. Cost incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) sufficient progress in assessing the reserves and the economic and operating viability of the project has been made. The status of suspended well costs is monitored continuously and reviewed quarterly. Due to the capital-intensive nature and the geographical characteristics of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and the economics associated with making a determination of its commercial viability.

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

We capitalize interest, if debt is outstanding, during drilling operations in our exploration and development activities.

Oil and Gas Reserves

Our estimates of proved reserves are based on the quantities of oil, natural gas and NGL, 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 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. Our independent petroleum engineers, Ryder Scott, prepare a reserve and economic evaluation of all of our properties on a well-by-well basis. The accuracy of reserve estimates is a function of the:

- quality and quantity of available data;
- interpretation of that data;
- accuracy of various mandated economic assumptions; and
- judgment of the independent reserve engineer.

One of the most significant estimates we make is the estimate of oil, natural gas and NGL reserves. Oil, natural gas and NGL reserve estimates require significant judgments in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may change substantially over time as a result of numerous factors including, but not limited to, additional development activity, production history, projected future production, economic assumptions relating to commodity prices, operating expenses, severance and other taxes, capital expenditures and remediation costs and these estimates are inherently uncertain. For example, if estimates of proved reserves decline, our DD&A rate will increase, resulting in a decrease in net income. A decline in estimates of proved reserves could also cause us to perform an impairment analysis to determine if the carrying amount of oil and gas properties exceeds fair value and could result in an impairment charge, which would reduce earnings. We cannot predict what reserve revisions may be required in future periods.

Ryder Scott estimated all of our proved reserve quantities as of December 31, 2018, 2017 and 2016. In connection with Ryder Scott performing their independent reserve estimations, we furnish them with the following information that they review: (1) technical support data, (2) technical analysis of geologic and engineering support information, (3) economic and production data and (4) our well ownership interests.

The following table presents information about proved reserve changes from period to period due to items we do not control, such as price, and from changes due to production history and well performance. These changes do not require a capital expenditure on our part, but may have resulted from capital expenditures we incurred to develop other estimated proved reserves.

	For the Year Ended December 31,		
	2018	2017	2016
Revisions resulting from price changes (MBOE)	11,082	12,767	(6,666)
Revisions resulting from production, performance and other (MBOE)	(14,407)	(9,873)	(955)
Total revisions (MBOE)	(3,325)	2,894	(7,621)

The recent significant decline in oil, natural gas and NGL prices increases the uncertainty as to the impact of commodity prices on our estimated proved reserves. We are unable to predict future commodity prices with any greater precision than the futures market. A prolonged period of depressed commodity prices may have a significant impact on the value and volumetric quantities of our proved reserve portfolio, assuming no other changes to our development plans or costs.

Depreciation, Depletion, Amortization and Accretion.

Our DD&A rate is dependent upon our estimates of total proved and proved developed reserves, which incorporate various assumptions and future projections. If our estimates of total proved or proved developed reserves decline, the rate at which we record DD&A expense increases, which in turn reduces our net income. Such a decline in reserves may result from lower commodity prices or other changes to reserve estimates, as discussed above, and we are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploration and development program, as well as future economic conditions.

Impairment of Proved Oil and Gas Properties

Proved oil and gas properties are reviewed for impairment annually or when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. We estimate the expected future cash flows of its oil and gas properties and compares these undiscounted cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will write down the carrying amount of the oil and gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures, estimated future operating costs, and discount rates commensurate with the risk associated with realizing the projected cash flows. Impairment expense for proved oil and gas properties is reported in impairment of long lived assets in the consolidated statements of operations, which increases accumulated depletion, depreciation and amortization.

For the years ended December 31, 2018 and 2016, we recognized \$16.2 million and \$22.5 million, respectively, in impairment expense on proved oil and gas properties in our northern field. As of September 30, 2018, the future undiscounted cash flows did not exceed the carrying amount associated with our proved oil and gas properties in the northern field. As of June 30, 2016, it was determined that the proved oil and gas properties had no remaining fair value, therefore, the full net book value of these proved oil and gas properties were impaired. For the year ended December 31, 2017, we recognized no impairment expense on proved oil and gas properties.

Our impairment analyses requires us to apply judgment in identifying impairment indicators and estimating future cash flows of our oil and gas properties. If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to an impairment charge.

Forward commodity prices and estimates of future production also play a significant role in determining impairment of proved oil and gas properties. As a result of lower commodity prices and their impact on our estimated future cash flows, we have continued to review our proved oil and gas properties for impairment. At December 31, 2018, our expected undiscounted future cash flows exceeded the carrying value of our proved oil and gas properties by approximately \$0.8 billion, or 30%. At December 31, 2017, our expected undiscounted future cash flows exceeded the carrying value of our proved oil and gas properties by approximately \$1.6 billion, or 68%. At December 31, 2016, our expected undiscounted future cash flows exceeded the carrying value of our proved oil and gas properties by approximately \$1.7 billion, or 108%. The key assumptions used to determine the undiscounted future cash flows include estimates of future production, future commodity pricing, differentials, net estimated operating costs, anticipated capital expenditures and new wells on production. Future commodity pricing for oil and NGL is based on five-year West Texas Intermediate strip prices, which decreased 8% from an average of \$54.66/Bbl at December 31, 2017 to an average of \$50.04/Bbl at December 31, 2018, and on five-year Henry Hub strip prices, which decreased 14% from an average of \$3.14/MMBtu at December 31, 2017 to an average of \$2.70/MMBtu at December 31, 2018.

Impairment of Unproved Oil and Gas Properties

Unproved oil and gas properties consist of costs to acquire unevaluated leases as well as costs to acquire unproved reserves. We evaluate significant unproved oil and gas properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage. When successful wells are drilled on undeveloped leaseholds, unproved property costs are reclassified to proved properties and depleted on a unit-of-production basis. Impairment expense and lease extension payments for unproved properties is reported in exploration expenses in the consolidated statements of operations. As a result of the abandonment and impairment of unproved properties, we recognized \$25.7 million, \$15.8 million and \$22.3 million in impairment expense for the years ended December 31, 2018, 2017 and 2016, respectively.

Goodwill and Other Intangible Assets

We apply the provisions of ASC 350, *Intangibles-Goodwill and Other*. Goodwill represents the excess of the purchase price over the estimated value of the net assets acquired in business combinations. We test goodwill for impairment annually on September 30, or whenever other circumstances or events indicate that the carrying amount of goodwill may not be recoverable. The goodwill test is performed at the reporting unit level, which represents our oil and gas operations in the core DJ Basin field. If indicators of impairment are determined to exist, an impairment charge is recognized if the carrying value of goodwill exceeds its implied fair value. Any sharp prolonged decreases in the prices of oil and natural gas as well as continued declines in the quoted market price of our common shares could change the estimates of the fair value of the reporting unit and could result in an impairment charge. We performed a quantitative assessment as of September 30, 2018, which concluded the fair value of the reporting unit was greater than its carrying amount. We identified triggering events as of December 31, 2018,

due to the decrease in commodity pricing and the quoted market price of the Company's common shares compared to September 30, 2018. As such, we performed a quantitative assessment as of December 31, 2018, utilizing an income approach based on estimates of the expected discounted future cash flows of the reporting unit's oil and gas properties, which concluded the fair value of the reporting unit was not greater than its carrying amount. As a result, we recorded goodwill impairment of \$54.2 million, the entirety of the balance, for the year ended December 31, 2018. We performed a quantitative assessment as of September 30, 2017, which concluded the fair value of the reporting unit was greater than its carrying amount. We performed a qualitative assessment as of December 31, 2017 and 2016, which concluded the fair value of the reporting unit was more-likely-than-not greater than its carrying amount.

Costs relating to the acquisition of internal-use software licenses are capitalized when incurred and amortized over the estimated useful life of the license.

Commodity Derivative Instruments

We have entered into commodity derivative instruments, as described below. We have utilized swaps, put options, and call options to reduce the effect of price changes on a portion of our 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 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 agree 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.

The objective of our 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 our ability to benefit from favorable price movements. We 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 our existing positions. We do not enter into derivative contracts for speculative purposes.

The commodity derivative instruments are measured at fair value and are included in the accompanying balance sheets as commodity derivative assets. We have not designated any of the derivative contracts as fair value or cash flow hedges. Therefore, we do not apply hedge accounting to the commodity derivative instruments. Net gains and losses on commodity derivative instruments are recorded based on the changes in the fair values of the derivative instruments. Net gains and losses on commodity derivative instruments are recorded in the commodity derivative gain (loss) line on the statements of operations. Our cash flow is only impacted when the actual settlements under the commodity derivative contracts result in making or receiving a payment to or from the counterparty. These settlements under the commodity derivative contracts are reflected as operating activities in our statements of cash flows.

Our valuation estimate takes into consideration the counterparties' credit worthiness, our credit worthiness, and the time value of money. The consideration of the factors result in an estimated exit-price for each derivative asset or liability under a market place participant's view. Management believes that this approach provides a reasonable, non-biased, verifiable, and consistent methodology for valuing commodity derivative instruments. Please see "—How We Evaluate Our Operations—Derivative Arrangements."

We account for all of our business combinations using the purchase method, which is the only method permitted under FASB ASC 805, *Business Combinations*, and involves the use of significant judgment. In connection with a business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Any excess or shortage of amounts assigned to assets and liabilities over or under the purchase price is recorded as a gain on bargain purchase or goodwill. The amount of goodwill or gain on bargain purchase recorded in any particular business combination can vary significantly depending upon the values attributed to assets acquired and liabilities assumed.

In estimating the fair values of assets acquired and liabilities assumed in a business combination, we make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved and unproved oil and gas properties. If sufficient market data is not available regarding the fair values of proved and unproved properties, we must prepare estimates. To estimate the fair values of these properties, we prepare estimates of gas, oil and NGL reserves. We estimate future prices to apply to the estimated reserves quantities acquired and estimate future operating and development costs to arrive at estimates of future net cash flows. For estimated proved reserves, the future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rate is subjected to additional project-specific risk factors. To compensate for the inherent risk of estimating and valuing unproved reserves, when a discounted cash flow model is used, the discounted future net cash flows of probable and possible reserves are reduced by additional risk factors. In some instances, market comparable information of recent transactions is used to estimate fair value of unproved acreage.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in higher DD&A expense, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value, or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded.

Asset Retirement Obligations

Our asset retirement obligations (“ARO”) consist of estimated future costs associated with the plugging and abandonment of oil, natural gas and NGL wells, removal of equipment and facilities from leased acreage and land restoration in accordance with applicable local, state and federal laws, and applicable lease terms. The fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and gas asset. The recognition of an ARO requires that management make numerous assumptions regarding such factors as the estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free discount rate to be used; and inflation rates. In periods subsequent to the initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to the passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A over the life of the oil and gas property.

Revenue Recognition

Revenues from the sale of oil, natural gas and NGL are recognized when the product is delivered at a fixed or determinable price, title has transferred, and collectability is reasonably assured and evidenced by a contract. We recognize revenues from the sale of oil, natural gas and NGL using the sales method of accounting, whereby revenue is recorded based on our share of volume sold, regardless of whether we have taken our proportional share of volume produced. A receivable or liability is recognized only to the extent that we have an imbalance on a specific property greater than the expected remaining proved reserves. We receive payment one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers and the price we will receive. Variances between our estimates and the actual amounts received are recorded in the month payment is received. A 10% change in our revenue accrual would have impacted total operating revenues by approximately \$9.1 million and \$9.3 million for the years ended December 31, 2018 and 2017, respectively.

Unit and Stock-Based Payments

The Company and its predecessor, Holdings, has granted restricted unit awards ("RUAs"), restricted stock units ("RSUs"), stock option awards and performance stock awards ("PSAs") to certain employees of the Company, which therefore required the Company to recognize the expense in its financial statements.

All unit and stock-based payments to employees are measured at fair value on the grant date and expensed over the relevant service period. The fair value of stock option awards is determined by using the Black-Scholes option pricing model. The fair value of the PSAs was measured at the grant date with a stochastic process method using a Monte Carlo simulation. All unit and stock-based payment expense is recognized using the straight-line method and is included within general and administrative expenses in the consolidated statements of operations and unit and stock-based compensation in the consolidated statements of cash flows. Forfeitures are recorded as they occur. Please refer to *Note 11 — Unit and Stock-Based Compensation* for additional discussion on unit and stock-based payments.

Income Taxes

We account for income taxes using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and operating loss and tax credit carry forwards. Deferred tax assets and liabilities are calculated by applying existing tax laws and the rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date. The tax returns and the amount of taxable income or loss are subject to examination by deferral and state taxing authorities.

We periodically assess whether it is more likely than not that it will generate sufficient taxable income to realize its deferred income tax assets, including net operating losses. In making this determination, we consider all the available positive and negative evidence and makes certain assumptions. We consider, among other things, our deferred tax liabilities, the overall business environment, its historical earnings and losses, current industry trends, and its outlook for future years. We believe it is more likely than not that certain net operating losses can be carried forward and utilized.

We recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. We do not currently have uncertain tax positions.

On December 22, 2017, United States legislation referred to as the TCJA was signed into law. Many of the provisions of the TCJA are effective for taxable years beginning after December 31, 2017. The TCJA includes changes to the Internal Revenue Code of 1986 (as amended, the "Code"). The most significant change included in the TCJA is a reduction in the corporate federal income tax rate from 35% to 21%. As a result of the enactment date of December 22, 2017, we were required to remeasure the deferred tax assets and liabilities at the rate in which they are expected to reverse. This re-measurement of deferred tax assets and liabilities required us to analyze and record a one-time adjustment to reduce the overall deferred tax liability in the consolidated balance sheets and affect a corresponding income tax benefit in the consolidated statements of operations for the year ended December 31, 2017. We believe the accounting is complete regarding the revaluation of the deferred tax balances. This resulted in the recording of an income tax benefit of \$23.4 million, as well as a corresponding reduction in the deferred tax liability as of December 31, 2017. During the third quarter of 2018, we completed the accounting for the income tax effect of the TCJA's limit on compensation under Internal Revenue Code Sec. 162(m) and stock-based compensation for covered employees. This resulted in a \$0.4 million reduction in deferred tax assets that had been recorded as a provisional amount as of December 31, 2017. There are no remaining provision amounts associated with the TCJA as of December 31, 2018.

Extraction Oil & Gas Holdings, LLC, our accounting predecessor, was a limited liability company that was not subject to U.S. federal income tax.

Recent Accounting Pronouncements

Please refer to Recent Accounting Pronouncements in *Note 2 — Basis of Presentation and Significant Accounting Policies* in Part II, Item 8 of this Annual Report.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

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

Commodity Price Risk

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

To reduce the impact of fluctuations in oil prices on our revenues, we periodically enter 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 and natural gas price fluctuations.

The following tables present our derivative positions related to crude oil and natural gas sales in effect as of December 31, 2018:

	For the Three Months Ended					
	March 31, 2019	June 30, 2019	September 30, 2019	December 31, 2019	March 31, 2020	June 30, 2020
NYMEX WTI Crude Swaps:						
Notional volume (Bbl)	—	—	450,000	450,000	600,000	600,000
Weighted average fixed price (\$/Bbl)	—	—	\$ 52.56	\$ 52.56	52.66	52.66
NYMEX WTI Crude Sold Calls:						
Notional volume (Bbl)	2,850,000	2,850,000	3,000,000	3,000,000	900,000	900,000
Weighted average sold call price (\$/Bbl)	\$ 63.68	\$ 63.68	\$ 67.04	\$ 67.04	\$ 67.53	\$ 67.53
NYMEX WTI Crude Sold Puts:						
Notional volume (Bbl)	2,850,000	2,850,000	3,900,000	3,900,000	900,000	900,000
Weighted average sold put price (\$/Bbl)	\$ 40.16	\$ 40.16	\$ 42.08	\$ 42.08	\$ 42.00	\$ 42.00
NYMEX WTI Crude Purchased Puts:						
Notional volume (Bbl)	4,725,000	4,725,000	4,200,000	4,200,000	900,000	900,000
Weighted average purchased put price (\$/Bbl)	\$ 46.05	\$ 46.05	\$ 49.50	\$ 49.50	\$ 50.00	\$ 50.00
NYMEX HH Natural Gas Swaps:						
Notional volume (MMBtu)	5,400,000	9,000,000	9,000,000	9,000,000	—	—
Weighted average fixed price (\$/MMBtu)	\$ 3.11	\$ 2.75	\$ 2.75	\$ 2.75	—	—
NYMEX HH Natural Gas Purchased Puts:						
Notional volume (MMBtu)	3,600,000	—	—	—	—	—
Weighted average purchased put price (\$/MMBtu)	\$ 3.04	—	—	—	—	—
NYMEX HH Natural Gas Sold Calls:						
Notional volume (MMBtu)	3,600,000	—	—	—	—	—
Weighted average sold call price (\$/MMBtu)	\$ 3.46	—	—	—	—	—
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)	9,000,000	9,000,000	9,000,000	9,000,000	—	—
Weighted average fixed basis price (\$/MMBtu)	\$ (0.75)	\$ (0.75)	\$ (0.75)	\$ (0.75)	—	—

As of December 31, 2018, the fair market value of our oil derivative contracts was a net asset of \$59.4 million. Based on our open oil derivative positions at December 31, 2018, a 10% increase in the NYMEX WTI price would decrease our net oil derivative asset by approximately \$43.4 million, while a 10% decrease in the NYMEX WTI price would increase our net oil derivative asset by approximately \$43.9 million. As of December 31, 2018, the fair market value of our natural gas derivative contracts was a net liability of \$2.3 million. Based upon our open commodity derivative positions at December 31, 2018, a 10% increase in the NYMEX Henry Hub price would increase our net natural gas derivative liability by approximately \$7.2 million, while a 10% decrease in the NYMEX Henry Hub price would decrease our net natural gas derivative liability by approximately \$7.3 million. Please see “—Derivative Arrangements.”

Counterparty and Customer Credit Risk

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

We sell oil, natural gas and NGL to various types of customers, including marketers. 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 year ended December 31, 2018, we had certain major customers that exceeded 10% of total oil, natural gas and NGL revenues. We do not believe the loss of any single purchaser would materially impact its operating results because oil, natural gas and NGL are fungible products with well-established markets and numerous purchasers.

At December 31, 2018, we had commodity derivative contracts with eleven counterparties, all of whom are lenders under our credit agreement. 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 years ended December 31, 2018, 2017 and 2016, we did not incur any losses with respect to counterparty contracts. None of our existing derivative instrument contracts contains credit-risk related contingent features.

Interest Rate Risk

At December 31, 2018, we had \$285.0 million of variable-rate debt outstanding. The impact on interest expense of a 1% increase or decrease in the average interest rate would be approximately \$2.9 million. 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. See “—Liquidity and Capital Resources—Debt Arrangements.”

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

EXTRACTION OIL & GAS, INC. INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Extraction Oil & Gas, Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Extraction Oil & Gas, Inc. and its subsidiaries (the “Company”) as of December 31, 2018 and 2017, and the related consolidated statements of operations, of changes in members’ and stockholders’ equity and noncontrolling interest and of cash flows for each of the three years in the period ended December 31, 2018, including the related notes (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management’s Annual Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company’s consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (“PCAOB”) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process designed 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. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Denver, Colorado
February 21, 2019

We have served as the Company's auditor since 2014.

EXTRACTION OIL & GAS, INC.
CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	December 31, 2018	December 31, 2017
ASSETS		
Current Assets:		
Cash and cash equivalents	\$ 234,986	\$ 6,768
Accounts receivable		
Trade	41,695	46,047
Oil, natural gas and NGL sales	91,225	93,301
Inventory and prepaid expenses	26,816	13,017
Commodity derivative asset	48,907	4,132
Assets held for sale	21,008	—
Total Current Assets	464,637	163,265
Property and Equipment (successful efforts method), at cost:		
Proved oil and gas properties	3,916,622	3,011,526
Unproved oil and gas properties	609,284	686,968
Wells in progress	144,323	127,418
Less: accumulated depletion, depreciation and amortization	(1,152,590)	(709,662)
Net oil and gas properties	3,517,639	3,116,250
Gathering systems and facilities (Note 2)	114,469	4,889
Other property and equipment, net of accumulated depreciation (Note 2)	39,849	32,429
Net Property and Equipment	3,671,957	3,153,568
Non-Current Assets:		
Commodity derivative asset	8,432	—
Goodwill and other intangible assets, net of accumulated amortization	2,156	55,453
Other non-current assets	18,845	12,383
Total Non-Current Assets	29,433	67,836
Total Assets	\$ 4,166,027	\$ 3,384,669
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	\$ 186,218	\$ 211,581
Revenue payable	117,344	52,805
Production taxes payable	57,516	37,444
Commodity derivative liability	196	67,428
Accrued interest payable	22,249	23,807
Asset retirement obligations	15,729	6,873
Liabilities related to assets held for sale	3,146	—
Total Current Liabilities	402,398	399,938
Non-Current Liabilities:		
Credit facility	285,000	90,000
Senior Notes, net of unamortized debt issuance costs (Note 5)	1,132,659	933,361
Production taxes payable	115,607	57,982
Commodity derivative liability	—	17,274
Other non-current liabilities	8,072	5,973
Asset retirement obligations	54,062	62,667
Deferred tax liability	109,176	42,326
Total Non-Current Liabilities	1,704,576	1,209,583
Total Liabilities	2,106,974	1,609,521
Commitments and Contingencies—Note 13		
Series A Convertible Preferred Stock, \$0.01 par value; 50,000,000 shares authorized; 185,280 and 185,280 issued and outstanding, respectively	164,367	158,383
Stockholders' Equity:		
Common Stock, \$0.01 par value; 900,000,000 shares authorized; 171,666,485 and 172,059,814 issued and outstanding, respectively	1,678	1,718
Treasury Stock, at cost, 4,543,262 and 165,385 shares, respectively	(32,737)	(2,105)
Additional paid-in capital	2,153,661	2,114,795
Accumulated deficit	(375,788)	(497,643)
Total Extraction Oil & Gas, Inc. Stockholders' Equity	1,746,814	1,616,765
Noncontrolling interest—(Note 9)	147,872	—
Total Stockholders' Equity	1,894,686	1,616,765
Total Liabilities and Stockholders' Equity	\$ 4,166,027	\$ 3,384,669

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

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

	For the Year Ended		
	December 31,		
	2018	2017	2016
Revenues:			
Oil sales	\$ 840,687	\$ 419,904	\$ 194,059
Natural gas sales	105,629	92,322	48,652
NGL sales	114,427	92,070	35,378
Total Revenues	1,060,743	604,296	278,089
Operating Expenses:			
Lease operating expenses	79,413	60,358	36,743
Transportation and gathering	39,411	50,948	25,300
Production taxes	90,345	51,367	20,730
Exploration expenses	31,611	36,256	36,422
Depletion, depreciation, amortization and accretion	435,775	314,999	205,348
Impairment of long lived assets and goodwill	70,928	1,647	23,425
Other operating expenses	—	—	10,891
(Gain) loss on sale of property and equipment and assets of unconsolidated subsidiary	(136,834)	451	—
Acquisition transaction expenses	—	—	2,719
General and administrative expenses	134,604	110,167	232,388
Total Operating Expenses	745,253	626,193	593,966
Operating Income (Loss)	315,490	(21,897)	(315,877)
Other Income (Expense):			
Commodity derivatives loss	(8,554)	(36,332)	(100,947)
Interest expense	(123,330)	(51,889)	(68,843)
Other income	5,099	2,010	386
Total Other Income (Expense)	(126,785)	(86,211)	(169,404)
Income (Loss) Before Income Taxes	188,705	(108,108)	(485,281)
Income tax (expense) benefit	(66,850)	63,700	29,280
Net Income (Loss)	121,855	(44,408)	(456,001)
Net income attributable to noncontrolling interest	7,287	—	—
Net Income (Loss) Attributable to Extraction Oil & Gas, Inc.	114,568	(44,408)	(226,107)
Adjustments to reflect Series A Preferred Stock dividends and accretion of discount	(16,869)	(16,279)	(3,999)
Net Income (Loss) Available to Common Shareholders, Basic and Diluted	\$ 97,699	\$ (60,687)	\$ (230,106)
Net Income (Loss) Per Common Share (Note 12)			
Basic and diluted	\$ 0.56	\$ (0.35)	\$ (1.54)
Weighted Average Common Shares Outstanding			
Basic and diluted	174,748	171,910	149,029

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

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

	Members' Units		Common Stock		Treasury Stock		Additional Paid in Capital	Retained Earnings (Deficit)	Extraction Oil & Gas, Inc. Stockholders' Equity	Noncontrolling	Total Stockholders' Equity
	Tranche A Units	Preferred Tranche C Units	Amount	Shares	Amount	Shares	Amount			Amount	
Balance at January 1, 2016	231,101	78,444	\$ 751,466	—	\$ —	—	\$ —	\$ 2,766	\$ 754,232	\$ —	\$ 754,232
Units issued	—	37,345	121,370	—	—	—	—	—	121,370	—	121,370
Units repurchased	(1,327)	(82)	(8,429)	—	—	—	—	—	(8,429)	—	(8,429)
Settlement of promissory notes issued to officers	—	—	5,562	—	—	—	—	—	5,562	—	5,562
Unit issuance costs	—	—	(1,022)	—	—	—	—	—	(1,022)	—	(1,022)
Restricted units issued	7,661	—	—	—	—	—	—	—	—	—	—
Unit-based compensation	—	—	14,922	—	—	—	—	—	14,922	—	14,922
Stock-based compensation	—	—	—	—	—	—	185,386	—	185,386	—	185,386
Corporate Reorganization of Extraction Oil & Gas Holdings and Extraction Oil & Gas, Inc.	(237,435)	(115,707)	(883,869)	108,461	1,085	—	882,784	—	—	—	—
Net deferred tax liability due to Corporate Reorganization	—	—	—	—	—	—	(135,306)	—	(135,306)	—	(135,306)
Issuance of common stock in initial public offering	—	—	—	38,333	383	—	727,950	—	728,333	—	728,333
Issuance of common stock in private placement	—	—	—	25,041	250	—	456,749	—	456,999	—	456,999
Common stock issuance costs	—	—	—	—	—	—	(62,437)	—	(62,437)	—	(62,437)
Dividends paid on Series A Preferred Units	—	—	—	—	—	—	(15,000)	—	(15,000)	—	(15,000)
Series A Preferred Units issuance costs	—	—	—	—	—	—	(1,233)	—	(1,233)	—	(1,233)
Series B Preferred Unit and Series A Preferred Stock dividends	—	—	—	—	—	—	(2,958)	—	(2,958)	—	(2,958)
Beneficial conversion feature on Series A Preferred Stock	—	—	—	—	—	—	32,696	—	32,696	—	32,696
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	—	—	(1,041)	—	(1,041)	—	(1,041)
Net loss	—	—	—	—	—	—	—	(456,001)	(456,001)	—	(456,001)
Balance at December 31, 2016	—	—	\$ —	171,835	\$ 1,718	—	\$2,067,590	\$ (453,235)	\$1,616,073	\$ —	\$ 1,616,073
Common stock issuance costs	—	—	—	—	—	—	(319)	—	(319)	—	(319)
Stock-based compensation	—	—	—	—	—	—	65,607	—	65,607	—	65,607
Series A Preferred Stock dividends	—	—	—	—	—	—	(10,885)	—	(10,885)	—	(10,885)
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	—	—	(5,394)	—	(5,394)	—	(5,394)
Repurchase of common stock	—	—	—	—	—	165	(2,105)	—	(2,105)	—	(2,105)
Shares issued under LTIP, including payment of tax withholdings using withheld shares	—	—	—	225	—	—	(1,804)	—	(1,804)	—	(1,804)
Net loss	—	—	—	—	—	—	—	(44,408)	(44,408)	—	(44,408)
Balance at December 31, 2017	—	—	\$ —	172,060	\$ 1,718	165	\$2,114,795	\$ (497,643)	\$1,616,765	\$ —	\$ 1,616,765
Preferred Units issued	—	—	—	—	—	—	—	—	—	148,500	148,500
Preferred Units issuance costs	—	—	—	—	—	—	—	—	—	(7,915)	(7,915)
Preferred Units commitment fees and dividends paid-in-kind	—	—	—	—	—	—	(7,287)	—	(7,287)	7,287	—
Stock-based compensation	—	—	—	2,794	—	—	68,349	—	68,349	—	68,349

	Members' Units		Common Stock		Treasury Stock		Additional Paid in Capital	Retained Earnings (Deficit)	Extraction Oil & Gas Stockholders' Equity	Noncontr olling	Total Stockhold ers' Equity
	Tranche A Units	Preferred Tranche C, Units	Amount	Shares	Amount	Shares	Amount	Amount	Amount	Amount	Amount
Series A Preferred Stock dividends	—	—	—	—	—	—	—	(10,885)	(10,885)	—	(10,885)
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	—	—	—	(5,984)	(5,984)	—	(5,984)
Repurchase of common stock	—	—	—	—	(40)	4,378	(30,632)	—	(30,672)	—	(30,672)
Shares issued under LTIP, including payment of tax withholdings	—	—	—	1,356	—	—	—	(5,327)	(5,327)	—	(5,327)
Net income	—	—	—	—	—	—	—	121,855	121,855	—	121,855
Balance at December 31, 2018	—	—	\$ —	176,210	\$ 1,678	4,543	\$ (32,737)	\$ 2,153,661	\$ 1,746,814	\$ 147,872	\$ 1,894,686

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

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

	For the Year Ended		
	December 31,		
	2018	2017	2016
Cash flows from operating activities:			
Net income (loss)	\$ 121,855	\$ (44,408)	\$ (456,001)
Reconciliation of net income (loss) to net cash provided by operating activities:			
Depletion, depreciation, amortization and accretion	435,775	314,999	205,348
Abandonment and impairment of unproved properties	25,704	15,808	22,318
Impairment of long lived assets and goodwill	70,928	1,647	23,425
(Gain) loss on sale of property and equipment	(53,222)	451	—
Gain on sale of assets of unconsolidated subsidiary	(83,612)	—	—
Amortization of debt issuance costs and debt discount	13,250	4,260	19,088
Deferred rent	348	(294)	551
Commodity derivatives loss	8,554	36,332	100,947
Settlements on commodity derivatives	(134,624)	(11,985)	42,827
Premiums paid on commodity derivatives	(22,749)	(475)	(611)
Earnings in unconsolidated subsidiaries	(2,862)	(415)	—
Distributions from unconsolidated subsidiary	1,684	415	—
Make-whole premium expense on 2021 Senior Notes	35,600	—	—
Prepayment penalty expense on Second Lien Notes	—	—	4,300
Deferred income tax expense (benefit)	66,850	(63,700)	(29,280)
Unit and stock-based compensation	68,349	65,607	200,308
Changes in current assets and liabilities:			
Accounts receivable—trade	8,562	(22,634)	(574)
Accounts receivable—oil, natural gas and NGL sales	2,076	(59,235)	(18,128)
Inventory and prepaid expenses	(853)	(523)	(1,110)
Accounts payable and accrued liabilities	(6,835)	31,202	(19,187)
Revenue payable	66,276	17,643	(6,602)
Production taxes payable	79,106	32,252	14,585
Accrued interest payable	(1,558)	4,186	19,171
Asset retirement expenditures	(13,669)	(4,168)	(687)
Net cash provided by operating activities	684,933	316,965	120,688
Cash flows from investing activities:			
Oil and gas property additions	(958,399)	(1,370,787)	(449,600)
Acquired oil and gas properties	—	(17,225)	(419,009)
Sale of property and equipment	80,879	5,155	2,656
Gathering systems and facilities additions	(81,406)	(4,452)	—
Other property and equipment additions	(15,991)	(17,737)	(7,655)
Investment in unconsolidated subsidiaries	(6,000)	—	—
Distributions from unconsolidated subsidiary, return of capital	—	518	—
Sale of assets of unconsolidated subsidiary	83,612	—	—
Net cash used in investing activities	(897,305)	(1,404,528)	(873,608)
Cash flows from financing activities:			
Borrowings under credit facility	635,000	565,000	263,000
Repayments under credit facility	(440,000)	(475,000)	(488,000)
Proceeds from the issuance of Senior Notes	739,664	394,000	550,000
Repayments of Second Lien Notes	—	—	(430,000)
Prepayment penalty paid on Second Lien Notes	—	—	(4,300)
Repayments of 2021 Senior Notes	(550,000)	—	—
Make-whole premium paid on 2021 Senior Notes	(35,600)	—	—
Proceeds from issuance of Preferred Units	148,500	—	—
Preferred Unit issuance costs	(6,915)	—	—
Proceeds from the issuance of units	—	—	121,370
Repurchase of stock and units	(30,672)	(2,105)	(2,867)

Payment of employee payroll withholding taxes	(5,327)	(1,804)	—
Issuance of common stock	—	—	1,185,332
Issuance of Series A Preferred Units	—	—	75,000
Redemption of Series A Preferred Units	—	—	(88,688)
Dividends on Series A Preferred Stock	(10,885)	(10,401)	—
Proceeds from the issuance of Series B Preferred Units	—	—	185,280
Dividends on Series B Preferred Units	—	—	(721)
Debt issuance costs	(3,166)	(4,627)	(14,102)
Equity issuance costs	(9)	(1,668)	(64,554)
Net cash provided by financing activities	440,590	463,395	1,286,750
Increase (decrease) in cash, cash equivalents and restricted cash	228,218	(624,168)	533,830
Cash, cash equivalents and restricted cash at beginning of period	6,768	630,936	97,106
Cash, cash equivalents and restricted cash at end of the period	\$ 234,986	\$ 6,768	\$ 630,936
Supplemental cash flow information:			
Property and equipment included in accounts payable and accrued liabilities	\$ 141,952	\$ 151,571	\$ 105,450
Cash paid for interest	\$ 84,224	\$ 54,492	\$ 31,280
Issuance of promissory note to unconsolidated subsidiary	\$ 35,329	\$ —	\$ —
Extinguishment of promissory note in exchange for equity with unconsolidated subsidiary	\$ (35,329)	\$ —	\$ —
Write-off of deposit on acquisition	\$ —	\$ —	\$ 10,000
Accretion of beneficial conversion feature	\$ 5,984	\$ 5,394	\$ 1,041
Noncash settlement of promissory notes issued to officers	\$ —	\$ —	\$ 5,562
Increase in dividends payable	\$ —	\$ 484	\$ —
Non-cash contribution to unconsolidated subsidiary	\$ —	\$ 8,738	\$ —
Preferred Units commitment fees and dividends paid-in-kind	\$ 7,287	\$ —	\$ —

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

EXTRACTION OIL & GAS, INC
NOTES TO 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 construction 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, 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 consolidated balance sheet. As of December 31, 2018, these gathering systems and facilities operations are not in service, therefore, there are no such revenues for the year then ended.

The consolidated financial statements for the period January 1, 2016 through October 12, 2016 are based on the financial statements of the Company’s accounting predecessor, Extraction Oil & Gas Holdings, LLC (“Holdings”) prior to the corporate reorganization (the “Corporate Reorganization”), pursuant to which, in connection with the initial public offering of the Company (the “Offering” or “IPO”), (i) on October 11, 2016, a former subsidiary of Extraction Oil & Gas Holdings, LLC, Extraction Oil & Gas, LLC, converted into the Company, and (ii) on October 17, 2016, Holdings merged with and into the Company with Extraction as the surviving entity.

Note 2—Basis of Presentation and Significant Accounting Policies

Basis of Presentation

The consolidated financial statements include the accounts of the Company, including its wholly-owned subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation. The financial statements included herein were prepared from the records of the Company in accordance with generally accepted accounting principles in the United States (“GAAP”). In the opinion of management, all adjustments, consisting primarily of normal recurring accruals that are considered necessary for a fair statement of the consolidated financial information, have been included.

Use of Estimates in the Preparation of Financial Statements

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant areas requiring the use of assumptions, judgments and estimates include (1) oil and gas reserves; (2) cash flow estimates used in impairment testing of oil and gas properties and goodwill; (3) depreciation, depletion, amortization and accretion; (4) asset retirement obligations; (5) assigning fair value and allocating purchase price in connection with business combinations, including the determination of any resulting goodwill; (6) accrued revenue and related receivables; (7) valuation of commodity derivative instruments; (8) accrued liabilities; (9) valuation of unit and stock-based payments, and (10) income taxes. Although management believes these estimates are reasonable, actual results could differ from these estimates. The Company evaluates its estimates on an on-going basis and bases its estimates on historical experience and on various other assumptions the Company believes to be reasonable under the circumstances.

Cash and Cash Equivalents

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

Restricted Cash

Restricted cash represents cash that is unavailable for use in the Company’s general operations. The Company had no restricted cash as of December 31, 2018 and 2017.

Cash Held in Escrow

Cash held in escrow includes deposits for the purchase of certain oil and gas properties as required under the related purchase and sale agreements. The Company had no cash held in escrow as of December 31, 2018 and 2017.

Accounts Receivable

The Company records estimated oil and gas revenue receivable from third parties at its net revenue interest. The Company also reflects costs incurred on behalf of joint interest partners in accounts receivable. The Company generally has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. On an on-going basis, management reviews accounts receivable amounts for collectability and records its allowance for uncollectible receivables under the specific identification method. The Company did not record any allowance for uncollectible receivables as of or for the years ended December 31, 2018 and 2017.

Credit Risk and Other Concentrations

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

The Company sells oil, natural gas and NGL to various types of customers, including oil marketers, pipelines and refineries. Credit is extended based on an evaluation of the customer's financial conditions and historical payment record. The future availability of a ready market for oil, natural gas and NGL depends on numerous factors outside the Company's control, none of which can be predicted with certainty. For the three years ended December 31, 2018, the Company had the following customers that exceeded 10% of total oil, natural gas and NGL revenues. The Company does not believe the loss of any single purchaser would materially impact its operating results because crude oil, natural gas and NGL are fungible products with well-established markets and numerous purchasers.

	For the Year Ended		
	December 31,		
	2018	2017	2016
Customer A	76%	65%	25%
Customer B	11%	19%	19%
Customer C	—%	11%	—%
Customer D	—%	—%	23%
Customer E	—%	—%	16%

At December 31, 2018, the Company had commodity derivative contracts with eleven counterparties, all of whom are lenders under our credit agreement. The Company does not require collateral or other security from counterparties to support derivative instruments; however, to minimize the credit risk in derivative instruments, it is the Company's policy to enter into derivative contracts only with counterparties that are credit worthy financial institutions deemed by management as competent and competitive market-makers. Additionally, the Company uses master netting agreements to minimize credit-risk exposure. The credit worthiness of the Company's counterparties is subject to periodic review. For the years ended December 31, 2018, 2017 and 2016, the Company did not incur any losses with respect to counterparty contracts. None of the Company's existing derivative instrument contracts contains credit-risk related contingent features.

Inventory and Prepaid Expenses

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

	As of December 31,	
	2018	2017
Well equipment inventory	\$ 19,916	\$ 9,971
Prepaid expenses	6,900	3,046
	<u>\$ 26,816</u>	<u>\$ 13,017</u>

Additionally, the Company recognized approximately \$0.1 million, \$0.7 million and \$0.4 million of impairment expense on well equipment inventory for the years ended December 31, 2018, 2017 and 2016, respectively.

Oil and Gas Properties

The Company follows the successful efforts method of accounting for oil and gas properties. Under this method of accounting, all property acquisition costs and development costs are capitalized when incurred and depleted on a units-of-production basis over the remaining life of proved reserves and proved developed reserves, respectively. For the years ended December 31, 2018, 2017 and 2016, the Company excluded \$144.3 million, \$127.4 million and \$98.7 million of capitalized costs from depletion related to wells in progress, respectively. For the years ended December 31, 2018, 2017 and 2016, the Company recorded depletion expense on capitalized oil and gas properties of \$426.8 million, \$306.7 million and \$197.4 million, respectively.

The costs of exploratory wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) sufficient progress in assessing the reserves and the economic and operating viability of the project has been made. The status of suspended well costs is monitored continuously and reviewed at each period end. Due to the capital-intensive nature and the geological characteristics of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and the economics associated with making a determination of its commercial viability. As of December 31, 2018, the Company had approximately \$6.1 million of suspended well costs, all capitalized less than one year and included in wells in progress at December 31, 2018. These exploratory well costs are pending further engineering evaluation and analysis to determine if economic quantities of oil and gas reserves have been discovered. The Company expects its analysis to be complete in the second half of 2019. As of December 31, 2017, \$15.7 million of suspended well costs, all capitalized less than one year and included in wells in progress as of December 31, 2017. At September 30, 2018, the Company completed its evaluation and moved \$17.9 million of these suspended well costs to proved oil and gas properties based on the determination of proved reserves. As of December 31, 2016, the Company had no suspended well costs recorded.

Geological and geophysical costs are expensed as incurred. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. Amounts of seismic costs capitalized are based on only those blocks of data used in determining development well locations. To the extent that a seismic project covers areas of both developmental and exploratory drilling, those seismic costs are proportionately allocated between development costs and exploration expense. The Company expensed \$0.4 million and \$1.4 million of costs associated with exploratory geological and geophysical costs for the years ended December 31, 2018 and 2017, respectively. There were no exploratory geological and geophysical costs incurred for the year ended December 31, 2016.

The Company capitalizes interest, if debt is outstanding, during drilling operations in its exploration and development activities. For the years ended December 31, 2018, 2017 and 2016, the Company capitalized interest of approximately \$8.2 million, \$11.1 million and \$5.2 million, respectively.

Net carrying values of retired, sold or abandoned properties that constitute less than a complete unit of depreciable property are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so

significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized in income. Gains or losses from the disposal of complete units of depreciable property are recognized to earnings.

For sales of entire working interests in unproved properties, gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of costs unless the proceeds exceed the entire cost of the property.

Impairment of Oil and Gas Properties

Proved oil and gas properties are reviewed for impairment annually or when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. For all of its fields, the Company estimates the expected future cash flows of its oil and gas properties and compares these undiscounted cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will write down the carrying amount of the oil and gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures, estimated future operating costs, and discount rates commensurate with the risk associated with realizing the projected cash flows. Impairment expense for proved oil and gas properties is reported in impairment of long lived assets and goodwill in the consolidated statements of operations, which increases accumulated depletion, depreciation and amortization. For the years ended December 31, 2018 and 2016, the Company recognized \$16.2 million and \$22.5 million, respectively, in impairment expense on proved oil and gas properties in the Company's northern field. As of September 30, 2018, the future undiscounted cash flows did not exceed its carrying amount associated with its proved oil and gas properties in its northern field. As of June 30, 2016, it was determined that the proved oil and gas properties had no remaining fair value, therefore, the full net book value of these proved oil and gas properties were impaired. For the year ended December 31, 2017, the Company recognized no impairment expense on proved oil and gas properties.

Unproved oil and gas properties consist of costs to acquire unevaluated leases as well as costs to acquire unproved reserves. The Company evaluates significant unproved oil and gas properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage. When successful wells are drilled on undeveloped leaseholds, unproved property costs are reclassified to proved properties and depleted on a unit-of-production basis. Impairment expense and lease extension payments for unproved properties is reported in exploration expenses in the consolidated statements of operations. As a result of the abandonment and impairment of unproved properties, the Company recognized \$25.7 million, \$15.8 million and \$22.3 million in impairment expense for the years ended December 31, 2018, 2017 and 2016, respectively.

Other Property and Equipment

Other property and equipment consists of (i) other property and equipment including, office furniture and fixtures, leasehold improvements and computer hardware and software, (iii) compressors used in Extraction's oil and gas operations, (iii) land, compressor stations, central tank batteries, and disposal well facilities and (iv) rights of ways, pipeline, and engineering costs. Impairment expense for other property and equipment is reported in impairment of long lived assets and goodwill in the consolidated statements of operations. The Company recognized \$0.4 million, \$0.9 million and \$0.5 million in impairment expense related to midstream facilities for the years ended December 31, 2018, 2017 and 2016, respectively, which increased accumulated depreciation recognized in other property and equipment, net of accumulated depreciation. The Company recognized the impairment expense for the year ended December 31, 2018 and 2017 primarily as the result of right-of-way options that were no longer in the Company's plans for developing midstream infrastructure. The Company recognized the impairment expense for the years ended December 31, 2016, as the result of contraction in the local oil and gas industry's near term growth profile, therefore decreasing the need and support for a specifically proposed gas processing facility. Gain or loss on the sale of other property and equipment is reported in (gain) loss on sale of property and equipment in the consolidated statement of operations. The Company recognized \$0.5 million of loss on the sale of other property and equipment related to the disposal of an oil pipeline that was not yet placed into service in the first quarter of 2017. Other property and equipment is recorded at cost and depreciated using the straight-line method.

The estimated useful lives of those assets depreciated under the straight-line basis are as follows:

Rental equipment	1-10 years
Office leasehold improvements	3-10 years
Other	3-5 years

Other property and equipment is comprised of the following (in thousands):

	As of December 31,	
	2018	2017
Rental equipment	\$ 4,043	\$ 3,805
Land	27,595	22,991
Right-of-ways and pipeline	8,008	7,447
Office leasehold improvements	7,231	4,405
Other	6,946	5,578
Less: accumulated depreciation and impairment	(13,974)	(11,797)
	<u>\$ 39,849</u>	<u>\$ 32,429</u>

Gathering Systems and Facilities

Gathering systems and facilities consist of midstream assets such as land, rights of way, pipelines, equipment and construction and engineering costs associated with the construction of pipeline infrastructure to serve the development of the Company's acreage in its Hawkeye and Southwest Wattenberg areas. Approximately \$112.3 million of gathering system and facilities assets have not been placed into service and therefore are not currently being depreciated. The Company will determine the estimated use lives of these assets when they are placed into service.

Gathering systems and facilities is comprised of the following (in thousands):

	As of December 31,	
	2018	2017
Gathering systems and facilities	112,281	4,889
Land associated with gathering systems and facilities	2,188	—
Less: accumulated depreciation	—	—
	<u>\$ 114,469</u>	<u>\$ 4,889</u>

Equity Method Investments

Investments in entities for which the Company exercises significant influence, but not control, are accounted for under the equity method. The Company recorded \$15.5 million and \$8.3 million of such investments included in other non-current assets on the consolidated balance sheets as of December 31, 2018 and 2017, respectively. The Company recognized \$2.9 million and \$0.4 million of income from such investments, including the accretion of any basis difference between the carrying amount of the investment and the amount of underlying equity in net assets, included in other income on the consolidated statements of operations and equity in earnings of unconsolidated subsidiary, in which we have a minority ownership interest on the consolidated statements of cash flows for the year ended December 31, 2018 and 2017, respectively. The Company held no such investments during the years ended December 31, 2016.

On August 3, 2018, Elevation received proceeds of \$83.6 million and recognized a gain of \$83.6 million for 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.

Deferred Lease Incentives

All incentives received from landlords for office leasehold improvements are recorded as deferred lease incentives and amortized over the term of the respective lease on a straight-line basis as a reduction of rental expense. Please refer to *Recent Accounting Pronouncements* for discussion related to Accounting Standard Update No. 2016-02, which updates the GAAP related to deferred lease incentives and will be effective as of January 1, 2019.

Debt Discount Costs

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

Debt Issuance Costs

Debt issuance costs include origination, legal, engineering, and other fees incurred to issue the debt in connection with the Company's credit facility, 2021 Senior Notes, 2024 Senior Notes and 2026 Senior Notes (collectively, the "Senior Notes"). Debt issuance costs related to the credit facility are included in other non-current assets on the consolidated balance sheets and amortized to interest expense on the consolidated statement of operations on a straight-line basis over the respective borrowing term. Debt issuance costs related to the Senior Notes are amortized to interest expense using the effective interest method over the term of the debt.

Commodity Derivative Instruments

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

Any premiums paid on derivative contracts are capitalized as part of the derivative assets or derivative liabilities, as appropriate, at the time the premiums are paid. Premium payments are reflected in cash flows from operating activities in the Company's consolidated statements of cash flows. Over time, as the derivative contracts settle, the differences between the cash received and the premiums paid or fair value of contracts acquired are recognized in net gains or losses on commodity or interest rate derivative contracts, and the cash received is reflected in cash flows from operating activities in the Company's consolidated statements of cash flows.

The Company's valuation estimate takes into consideration the counterparties' credit worthiness, the Company's credit worthiness, and the time value of money. The consideration of these factors result in an estimated exit-price for each derivative asset or liability under a market place participant's view. Management believes that this approach provides a reasonable, non-biased, verifiable, and consistent methodology for valuing commodity derivative instruments. Please refer to *Note 6 — Commodity Derivative Instruments* for additional discussion on commodity derivative instruments.

Goodwill and Other Intangible Assets

The Company applies the provisions of ASC 350, *Intangibles-Goodwill and Other*. Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in business combinations. The Company tests goodwill for impairment annually on September 30, or whenever other circumstances or events indicate that the carrying amount of goodwill may not be recoverable. The goodwill test is performed at the reporting unit level, which represents the Company's oil and gas operations in its core DJ Basin field. If indicators of impairment are determined to exist, an impairment charge is recognized if the carrying value of goodwill exceeds its implied fair value. Any sharp prolonged decreases in the prices of oil and natural gas as well as continued declines in the quoted market price of the Company's common shares could change the estimates of the fair value of the reporting unit and could result in an impairment charge. The Company performed a quantitative assessment as of September 30, 2018, which concluded the fair value of the reporting unit was greater than its

carrying amount. The Company identified triggering events as of December 31, 2018, due to the decrease in commodity pricing and the quoted market price of the Company's common shares compared to September 30, 2018. As such, the Company performed a quantitative assessment as of December 31, 2018, utilizing an income approach based on estimates of the expected discounted future cash flows of the reporting unit's oil and gas properties, which concluded the fair value of the reporting unit was not greater than its carrying amount. As a result, the Company recorded goodwill impairment of \$54.2 million, the entirety of the balance, for the year ended December 31, 2018. The Company performed a quantitative assessment as of September 30, 2017, which concluded the fair value of the reporting unit was greater than its carrying amount. The Company performed a qualitative assessment as of December 31, 2017 and 2016, which concluded the fair value of the reporting unit was more-likely-than-not greater than its carrying amount.

Costs relating to the acquisition of internal-use software licenses are capitalized when incurred and amortized over the estimated useful life of the license, which is typically one to three years. The Company recorded \$3.0 million, \$2.3 million and \$0.3 million of internal-use software for the years ended December 31, 2018, 2017 and 2016, respectively, on the consolidated balance sheets within the goodwill and other intangible assets line item. Accumulated amortization for the years ended December 31, 2018, and 2017 was \$3.1 million and \$1.1 million, respectively. The Company recognized \$2.1 million, \$1.0 million and \$0.1 million amortization expense for the years ended December 31, 2018, 2017 and 2016, respectively.

Fair Value of Financial Instruments

The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable, accounts payable, commodity derivative instruments (discussed above) and long-term debt. The carrying values of cash and cash equivalents, accounts receivable and accounts payable are representative of their fair values due to their short-term maturities. The carrying amount of the Company's credit facility approximates fair value as it bears interest at variable rates over the term of the loan. The Company's Senior Notes are recorded at cost and the fair value is disclosed in *Note 8 — Fair Value Measurements*. Considerable judgment is required to develop estimates of fair value. The estimates provided are not necessarily indicative of the amounts the Company would realize upon the sale or refinancing of such instruments.

Asset Retirement Obligation

The Company recognizes estimated liabilities for future costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time the Company makes the decision to complete the well or a well is acquired. For additional discussion on asset retirement obligations please refer to *Note 7 — Asset Retirement Obligations*.

Environmental Liabilities

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

Liabilities for expenditures of a non-capital nature are recorded when environmental assessments and/or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted values unless the timing of cash payments for the liability or component is fixed or determinable. Management has determined that no significant environmental liabilities existed as of December 31, 2018.

Revenue Recognition

Revenues from the sale of oil, natural gas and NGL are recognized when the product is delivered at a fixed or determinable price, title has transferred, and collectability is reasonably assured and evidenced by a contract. The Company recognizes revenues from the sale of oil, natural gas and NGL using the sales method of accounting, whereby revenue is recorded based on the Company's share of volume sold, regardless of whether the Company has taken its proportional share of volume produced. A receivable or liability is recognized only to the extent that the Company has an imbalance on a specific property greater than the expected remaining proved reserves. As of December 31, 2018, the Company has an oil imbalance of 22 MBbl, which the Company intends to settle with the counterparty in crude oil barrels. There were no material imbalances at December 31, 2017 or 2016.

On January 1, 2018, the Company adopted ASC 606 - Revenue from Contracts with Customers ("ASC 606"). See *Adoption of ASC 606* for more information regarding the adoption of this standard.

Unit and Stock-Based Payments

The Company and its predecessor, Holdings, has granted restricted unit awards ("RUAs"), restricted stock units ("RSUs"), stock option awards and performance stock awards ("PSAs") to certain directors, officers and employees of the Company, which therefore required the Company to recognize the expense in its financial statements.

All unit and stock-based payments to directors, officers and employees are measured at fair value on the grant date and expensed over the relevant service period. The fair value of stock option awards is determined by using the Black-Scholes option pricing model. The fair value of the PSAs was measured at the grant date with a stochastic process method using a Monte Carlo simulation. All unit and stock-based payment expense is recognized using the straight-line method and is included within general and administrative expenses in the consolidated statements of operations and unit and stock-based compensation in the consolidated statements of cash flows. Forfeitures are recorded as they occur. Please refer to *Note 11 — Unit and Stock-Based Compensation* for additional discussion on unit and stock-based payments.

Income Taxes

The Company accounts for income taxes using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and operating loss and tax credit carry forwards. Deferred tax assets and liabilities are calculated by applying existing tax laws and the rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date. The tax returns and the amount of taxable income or loss are subject to examination by deferral and state taxing authorities.

The Company periodically assesses whether it is more likely than not that it will generate sufficient taxable income to realize its deferred income tax assets, including net operating losses. In making this determination, the Company considers all the available positive and negative evidence and makes certain assumptions. The Company considers, among other things, its deferred tax liabilities, the overall business environment, its historical earnings and losses, current industry trends, and its outlook for future years. The Company believes it is more likely than not that certain net operating losses can be carried forward and utilized.

The Company recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. The Company does not currently have uncertain tax positions.

On December 22, 2017, United States legislation referred to as the Tax Cuts and Jobs Act (the "TCJA") was signed into law. Many of the provisions of the TCJA are effective for taxable years beginning after December 31, 2017. The TCJA includes changes to the Internal Revenue Code of 1986 (as amended, the "Code"). The most significant change included in the TCJA is a reduction in the corporate federal income tax rate from 35% to 21%. As a result of the enactment date of December 22, 2017, the Company was required to remeasure the deferred tax assets and liabilities at the rate in which they are expected to reverse. This re-measurement of deferred tax assets and liabilities required the Company to analyze and record a one-time adjustment to reduce the overall deferred tax liability in the consolidated balance sheets and affect a corresponding income tax benefit in the consolidated statements of operations for the year ended December 31, 2017. The Company believes the accounting is complete regarding the revaluation of the deferred tax balances. This resulted in the recording of an income tax benefit of \$23.4 million, as well as a corresponding reduction in the deferred tax liability as of December 31, 2017. During the third quarter of 2018, we completed the accounting for the income tax effect of the TCJA's limit on compensation under Internal Revenue Code Sec. 162(m) and stock-based compensation for covered employees. This resulted in a \$0.4 million reduction in deferred tax assets that had been recorded as a provisional amount as of December 31, 2017. There are no remaining provisional amounts associated with the TCJA as of December 31, 2018.

Extraction Oil & Gas Holdings, LLC, the Company's accounting predecessor, was a limited liability company that was not subject to U.S. federal income tax.

Earnings 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 available to common shareholders of the Company. The Company uses the “if-converted” method to determine the potential dilutive effects of its Series A Preferred Stock, and the treasury stock method to determine the potential dilutive effect of outstanding restricted stock units and stock option awards. The Company’s EPS calculation for the year ended December 31, 2016 includes only the net income (loss) for the period subsequent to IPO and Corporate Reorganization which occurred on October 12, 2016 and has omitted EPS prior to this date. In addition, the basic weighted average shares outstanding calculation for the year ended December 31, 2016 is based on the actual days in which the shares were outstanding for the period from October 12, 2016, to December 31, 2016.

Segment Reporting

Beginning in the fourth quarter of 2018, the Company had 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 is currently under development. 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 activity of the exploration and production segment and gathering systems and facilities operating segment are being monitored by our chief operating decision maker (“CODM”). The Company expects the first phase of the gathering systems and facilities to be operational during the second half of 2019. Revenues associated with the exploration and production segment 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. Revenues and operating expenses associated with the gathering systems and facilities operations will be primarily derived from intersegment transactions for services provided to the Company’s exploration, development and production operations by Elevation Midstream, LLC., an unrestricted subsidiary to the Company. All intersegment transactions are and will be eliminated upon consolidation, including revenues and operating expenses during the construction of and from gathering services provided by Elevation Midstream to the Company. The CODM considers Adjusted EBITDAX as the measure of segment performance under ASC 280, *Segment Reporting*. Accounting policies for each segment are the same as the accounting policies as described herein. For more information about Segments, see *Note 15 — Segment Information*.

All of the Company’s operations are conducted in one geographic area of the United States. All revenues are derived from customers located in the United States.

Recent Accounting Pronouncements

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

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

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

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

In February 2017, the FASB issued ASU No. 2017-05, which provided clarification regarding the guidance on accounting for the derecognition of nonfinancial assets. For public entities, the new guidance was effective for fiscal years beginning after December 15, 2017, including interim reporting periods within that fiscal year. The Company adopted this ASU on January 1, 2018 and the adoption of this ASU did not have a material impact on the consolidated financial statements and related disclosures.

In January 2017, the FASB issued ASU No. 2017-04, which simplifies how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. Step 2 measures a goodwill impairment loss by comparing the implied fair value of a reporting unit's goodwill with the carrying amount. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2019. Early adoption is permitted for interim and annual goodwill impairment tests performed on testing dates after January 1, 2017. The Company is currently evaluating the impact of adopting this ASU, however it is not expected to have a significant effect on its consolidated financial statements and related disclosures.

In January 2017, the FASB issued ASU No. 2017-01, which clarifies the definition of a business when evaluating whether transactions should be accounted for as acquisitions or disposals of assets or businesses. For public entities, the new guidance was effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. The Company adopted this ASU on January 1, 2018 and the adoption of this ASU did not have a material impact on the consolidated financial statements and related disclosures; however, this standard may result in more transactions being accounted for as asset acquisitions rather than business combinations.

In November 2016, the FASB issued ASU No. 2016-18, which intends to clarify how entities should present restricted cash and restricted cash equivalents in the statement of cash flows. This amendment was effective retrospectively for reporting periods beginning after December 15, 2017. The Company adopted this ASU on January 1, 2018 and the retrospective adoption increased the Company's beginning cash balances within the statement of cash flows for the prior period presented in the table below. The adoption had no other material impact on the cash flow statement and had no impact on the Company's results of operations or financial position.

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

	As of			
	December 31, 2018	December 31, 2017	December 31, 2016	December 31, 2015
Cash and cash equivalents	\$ 234,986	\$ 6,768	\$ 588,736	\$ 97,106
Restricted cash included in cash held in escrow	—	—	42,200	—
	<u>\$ 234,986</u>	<u>\$ 6,768</u>	<u>\$ 630,936</u>	<u>\$ 97,106</u>

In August 2016, the FASB issued ASU No. 2016-15, which addresses eight specific cash flow issues, including presentation of debt prepayments or debt extinguishment costs, with the objective of reducing the existing diversity in practice. For public entities, the new guidance was effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. The Company adopted this ASU on January 1, 2018, which requires current period make-whole premiums to be presented in financing activities in the statement of cash flows and prior period debt prepayment costs to be reclassified from operating activities to financing activities in the statement of cash flows; however, there was no impact to the total change in cash and cash equivalents from period to period.

In February 2016, the FASB issued ASU No. 2016-02, which requires lessee recognition on the balance sheet of a right of use asset and a lease liability, initially measured at the present value of the lease payments. It further requires recognition in the income statement of a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a generally straight-line basis. Finally, it requires classification of all cash payments within operating activities in the statements of cash flows. It is effective for fiscal years commencing after December 15, 2018 and early adoption is permitted. The FASB subsequently issued ASU No. 2017-13, ASU No. 2018-01, ASU No. 2018-10 and ASU No. 2018-11, which provided additional implementation guidance. The Company is currently evaluating the impact this ASU will have on the consolidated financial statements and related disclosures and expects certain lease agreements with terms over one year to be classified as right-of-use assets and right-of-use liabilities, which will gross up the consolidated balance sheet as of January 1, 2019. The Company will adopt 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 consolidated balance sheet. The Company is finalizing its evaluation of the impacts that the adoption of this accounting guidance will have on the consolidated financial statements and on our future consolidated balance sheet upon adoption. As a part of the implementation work, the Company is validating the inputs and outputs of the software tool used to calculate the initial and ongoing accounting balances for right-of-use assets and liabilities and finalizing the completeness of the lease population.

In May 2014, the FASB issued ASU No. 2014-09, which establishes a comprehensive new revenue recognition model, referred to as ASC 606 - Revenue from Contracts with Customers, designed to depict the transfer of goods or services to a customer in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. The ASU allows for the use of either the full or modified retrospective transition method. In August 2015, the FASB issued ASU No. 2015-14, which deferred ASU No. 2014-09 for one year, and was effective for annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period. The FASB subsequently issued ASU No. 2016-08, ASU No. 2016-10, ASU No. 2016-11, ASU No. 2016-12, ASU No. 2016-20, ASU No. 2017-13, ASU No. 2017-14 and ASU No. 2019-20, which provided additional implementation guidance. Refer to —*Adoption of ASC 606* for more information.

Adoption of ASC 606

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

The impact of adoption in the year ended December 31, 2018 results are as follows (in thousands):

	Under ASC 606	Under ASC 605	Change
Revenues:			
Oil sales	\$ 840,687	\$ 840,687	\$ —
Natural gas sales	105,629	121,180	(15,551)
NGL sales	114,427	134,558	(20,131)
Total Revenues	1,060,743	1,096,425	(35,682)
Operating Expenses:			
Transportation and gathering	\$ 39,411	\$ 75,093	\$ (35,682)
Revenues less transportation and gathering	\$ 1,021,332	\$ 1,021,332	\$ —

Changes to sales of natural gas and NGL, and transportation and gathering expenses are due to the conclusion that certain midstream processing entities are the Company's customers in natural gas processing and marketing agreements in accordance with the five-step process in ASC 606. This is a change from previous conclusions reached for these agreements utilizing the principal versus agent indicators under ASC 605 where the Company determined it was the principal, the midstream processor was the agent and the third-party end user was its customer. As a result, the Company modified its presentation of revenues and operating expenses for these agreements. Revenues related to these agreements are now presented on a net basis for proceeds expected to be received from the midstream processing entity. Revenues from the sale of oil, natural gas and NGL, where the Company is a non-operating interest partner, are considered in the scope of *ASC 808 - Collaborative Arrangements*. Therefore, ASC 606 did not change the presentation of these revenues.

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

Revenues from Contracts with Customers

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

Oil Sales

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

The Company utilizes the sales method to account for producer imbalances, which continues to be applicable under ASC 606. As of December 31, 2018, the Company has an oil imbalance of 22 MBbl, which the Company intends to settle with the counterparty in crude oil barrels.

Natural Gas and NGL Sales

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

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

Performance Obligations

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

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

The Company records revenue on its oil, natural gas and NGL sales at the time production is delivered to the purchaser. However, settlement statements for certain oil, natural gas and NGL sales may not be received for 30 to 90 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production delivered to the customer and the net commodity price that will be received for the sale of these commodity products. The Company records the differences between the revenue estimated and the actual amounts received for product sales in the month that payment is received from the customer. The Company has internal controls over its revenue estimation process and related accruals, and

any identified differences between its revenue estimates and actual revenue received historically have not been significant. For the period from January 1, 2018 to December 31, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

Contract Balances

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

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

	For the Year Ended December 31,		
	2018	2017	2016
Revenues:			
Oil sales	\$ 840,687	\$ 419,904	\$ 194,059
Natural gas sales	121,180	92,322	48,652
NGL sales	134,558	92,070	35,378
Transportation and gathering included in revenues	(35,682)	—	—
Total Revenues	\$ 1,060,743	\$ 604,296	\$ 278,089

There are no other accounting standards applicable to the Company that have been issued but not yet adopted by the Company as of December 31, 2018, and through the date of this filing that would have a material impact on the Company's consolidated financial statements and related disclosures.

Note 3—Oil and Gas Properties

The Company's oil and gas properties are entirely within the United States. The net capitalized costs related to the Company's oil and gas producing activities were as follows (in thousands):

	As of December 31,	
	2018	2017
Proved oil and gas properties	\$ 3,916,622	\$ 3,011,526
Unproved oil and gas properties ⁽¹⁾	609,284	686,968
Wells in progress ⁽²⁾	144,323	127,418
Total capitalized costs ⁽³⁾	\$ 4,670,229	\$ 3,825,912
Accumulated depletion, depreciation and amortization	(1,152,590)	(709,662)
Net capitalized costs	<u>\$ 3,517,639</u>	<u>\$ 3,116,250</u>

- (1) Unproved oil and gas properties represent unevaluated costs the Company excludes from the amortization base until proved reserves are established or impairment is determined.
- (2) Costs from wells in progress are excluded from the amortization base until production commences.
- (3) Includes accumulated interest capitalized of \$32.6 million, \$24.5 million and \$13.4 million as of December 31, 2018, 2017 and 2016, respectively.

The following table presents information regarding the Company's net costs incurred in oil and gas property acquisition, exploration and development activities (in thousands):

	For the Year Ended December 31,	
	2018	2017
Property acquisition costs:		
Proved	\$ 46,052	\$ 139,481
Unproved	79,708	382,213
Exploration costs ⁽¹⁾	8,840	17,074
Development costs	776,528	894,040
Total	<u>\$ 911,128</u>	<u>\$ 1,432,808</u>
Total excluding asset retirement costs	<u>\$ 902,241</u>	<u>\$ 1,420,235</u>

(1) Exploration costs do not include impairment and abandonment costs of unproved properties, which are included in the line item exploration expenses in the consolidated statements of operations.

Note 4—Acquisitions and Divestitures

Assets Held for Sale

In January 2019, the Company entered into a definitive agreement with an unaffiliated oil and gas company to sell approximately 5,000 net acres of leasehold and producing properties primarily in Weld County, Colorado (the "Proposed March 2019 Divestiture") from its exploration and production segment. Upon closing, the Company will receive total consideration of approximately \$22.4 million in cash, subject to customary purchase price adjustments. The effective date for the Proposed March 2019 Divestiture is July 1, 2018 with purchase price adjustments calculated as of the closing date, which is scheduled for late March 2019. These assets are classified as held for sale on the consolidated balance sheets.

The following table presents the information related to the assets held for sale in the December 31, 2018 consolidated balance sheet (in thousands):

	December 31, 2018
Assets:	
Property and equipment	
Proved oil and gas properties, net	\$ 11,945
Unproved oil and gas properties	9,063
Total Assets Held for Sale	<u>\$ 21,008</u>
Liabilities:	
Revenue payable	\$ 1,737
Production taxes payable	1,409
Total liabilities held for sale	<u>\$ 3,146</u>
Total Assets Held for Sale, Net	<u>\$ 17,862</u>

The assets held for sale as of December 31, 2018 do not qualify for discontinued operations as they do not represent a strategic shift that will have a major effect of the Company's operations or financial results.

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.

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 (the "April 2018 Acquisition"). Upon closing the seller received approximately \$9.4 million in cash. This transaction has been accounted for as an asset acquisition. The acquisition provided new development opportunities in the Core DJ Basin.

January 2018 Acquisition

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

November 2017 Acquisition

On November 15, 2017, the Company acquired an unaffiliated oil and gas company's interest in approximately 36,600 net acres of leasehold and primarily non-producing properties located in Arapahoe County, Colorado, (the "November 2017 Acquisition"). Upon closing the seller received \$214.3 million in cash, subject to customary purchase price adjustments. The Company also recorded a liability of \$12.2 million for the final settlement payment due in April 2018 in conjunction with November 2017 Acquisition, which was reflected in the December 31, 2017 consolidated balance sheets within the accounts payable and accrued liabilities line item. This transaction has been accounted for as an asset acquisition. The acquisition provided new development opportunities in the Core DJ Basin.

July 2017 Acquisition

On July 7, 2017, the Company acquired an unaffiliated oil and gas company's interests in approximately 12,500 net acres of leasehold and primarily non-producing properties located primarily in Adams County, Colorado, (the "July 2017 Acquisition"). Upon closing the seller received total consideration of \$84.0 million in cash. The effective date for the July 2017 Acquisition is July 1, 2017. This transaction has been accounted for as an asset acquisition. The acquisition provided new development opportunities in the Core DJ Basin.

June 2017 Acquisition

On June 8, 2017, the Company acquired an unaffiliated oil and gas company's interests in approximately 160 net acres of leasehold and related producing properties located in Weld County, Colorado (the "June 2017 Acquisition"). The Company paid approximately \$13.4 million in cash consideration in connection with the closing of the June 2017 Acquisition. The effective date for the acquisition was January 1, 2017, with purchase price adjustments calculated as of the closing date of June 8, 2017. The acquisition increased the Company's interest in existing operated wells. The acquired producing properties contributed \$3.3 million of revenue and \$2.5 million of earnings, respectively, for the year ended December 31, 2018. The acquired producing properties contributed \$3.7 million of revenue and \$3.0 million of earnings, respectively, for the year ended December 31, 2017. The acquired producing properties contributed no revenue and earnings for the years ended December 31, 2016. No significant transaction costs related to the acquisition were incurred for the years ended December 31, 2018, 2017 and 2016.

The June 2017 Acquisition was accounted for using the acquisition method under ASC 805, *Business Combinations*, which required the acquired assets and liabilities to be recorded at fair value as of the acquisition date of June 8, 2017. In August 2017, the Company completed the transaction's post-closing settlement. The following table summarizes the purchase price and the final allocation of the fair values of assets acquired and liabilities assumed (in thousands):

Purchase Price	June 8, 2017
Consideration given	
Cash	\$ 13,395
Total consideration given	<u>\$ 13,395</u>
Allocation of Purchase Price	
Proved oil and gas properties	\$ 13,495
Total fair value of oil and gas properties acquired	<u>\$ 13,495</u>
Asset retirement obligations	<u>\$ (100)</u>
Fair Value of Net Assets Acquired	<u><u>\$ 13,395</u></u>

November 2016 Acquisition

On November 22, 2016, the Company acquired an unaffiliated oil and gas company's interest in approximately 9,200 net acres of leaseholds located in the Core DJ Basin for approximately \$120.0 million, including customary closing adjustments. The Company also made a \$41.1 million deposit in November 2016 in conjunction with the November 2016 Acquisition. The deposit was made for two additional closings of leaseholds located in the Core DJ Basin. The first closing occurred in January 2017 and added approximately 5,300 net acres for approximately \$26.8 million. The second closing occurred in July 2017 and added approximately 640 net acres for approximately \$10.9 million. This transaction has been accounted for as an asset acquisition.

October 2016 Acquisition

On October 3, 2016, the Company acquired an unaffiliated oil and gas company's interests in approximately 6,400 net acres of leasehold, and related producing and non-producing properties located primarily in Weld County, Colorado, along with various other related rights, permits, contracts, equipment, rights of way, gathering systems and other assets (the "October 2016 Acquisition"). The seller received aggregate consideration of approximately \$405.3 million in cash. The effective date for the acquisition was July 1, 2016, with purchase price adjustments calculated as of the closing date on October 3, 2016. The acquisition provided new development opportunities in the DJ Basin as well as increases the Company's existing working interest, as the majority of the locations are located on acreage in which the Company already owns a majority working interest and operates. The acquired producing properties contributed revenue of \$17.2 million for the year ended December 31, 2016. The Company determined that it is not practical to calculate net income associated with October 2016 Acquisition. The Company incurred \$2.6 million of transaction costs related to the acquisition for year ended December 31, 2016. These transaction costs are recorded in the consolidated statements of operations within the acquisition transaction expenses line item. No transaction costs related to the acquisition were incurred for the years ended December 31, 2018 and 2017.

The acquisition is accounted for using the acquisition method under *ASC 805, Business Combinations*, which requires the acquired assets and liabilities to be recorded at fair value as of the acquisition date of October 3, 2016. In February 2017, the Company completed the transaction's post-closing settlement. The following table summarizes the purchase price and the final allocation of the fair values of assets acquired and liabilities assumed (in thousands):

Purchase Price	October 3, 2016
Consideration given	
Cash	\$ 405,335
Total consideration given	<u>\$ 405,335</u>
Allocation of Purchase Price	
Proved oil and gas properties	\$ 252,522
Unproved oil and gas properties	109,800
Total fair value of oil and gas properties acquired	<u>\$ 362,322</u>
Goodwill ⁽¹⁾	\$ 54,220
Working capital	(7,185)
Asset retirement obligations	<u>(4,022)</u>
Fair Value of Net Assets Acquired	<u><u>\$ 405,335</u></u>
Working capital acquired was estimated as follows:	
Accounts receivable	\$ 955
Revenue payable	(3,012)
Production taxes payable	(4,244)
Accrued liabilities	(884)
Total working capital	<u><u>\$ (7,185)</u></u>

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

Option to Acquire Additional Assets from October 2016 Acquisition

Upon the closing of the October 2016 Acquisition, the Company made a \$10.0 million non-refundable payment for an option to purchase additional assets from the seller of the October 2016 Acquisition (the "Additional Assets") for an additional \$190.0 million, for a total purchase price for the Additional Assets of \$200.0 million. The option may have been exercised at any time until March 31, 2017. If the Company did not exercise the option to acquire the Additional Assets, the seller would have had the right until April 30, 2017 to elect to sell those assets to the Company for an additional \$120.0 million, for a total purchase price for the Additional Assets of \$130.0 million. In March 2017, the Company entered into an amendment to this agreement with the seller to terminate both the Company's and seller's options for no further consideration. The \$10.0 million was expensed in the fourth quarter of 2016 to other operating expenses within the consolidated statements of operations.

August 2016 Acquisition

On August 23, 2016, the Company acquired an unaffiliated oil and gas company's interests in approximately 1,400 net acres of leasehold located primarily in Weld County, Colorado, along with various other related rights, permits, contracts, equipment, rights of way and other assets (the "August 2016 Acquisition"). The seller received aggregate consideration of approximately \$17.5 million in cash. The effective date for the acquisition was August 31, 2016, with purchase price adjustments calculated as of the closing date of August 23, 2016. The acquisition provided new development opportunities in the DJ Basin as well as additions adjacent to the Company's core project area. The Company incurred \$0.1 million of transaction costs related to the acquisition. These transaction costs were recorded in the condensed consolidated statements of operations within the acquisition transaction expenses line item in the third quarter of 2016.

The acquisition was accounted for using the acquisition method under ASC 805, *Business Combinations*, which required the acquired assets and liabilities to be recorded at fair value as of the acquisition date of August 23, 2016. In March 2017, the Company completed the transaction's post-closing settlement. The following table summarizes the purchase price and the final allocation of the fair values of assets acquired and liabilities assumed (in thousands):

Purchase Price	August 23, 2016
Consideration given	
Cash	\$ 17,504
Total consideration given	<u>\$ 17,504</u>
Allocation of Purchase Price	
Proved oil and gas properties	\$ 12,362
Unproved oil and gas properties	8,566
Total fair value of oil and gas properties acquired	<u>\$ 20,928</u>
Working capital	\$ (9)
Asset retirement obligations	(3,415)
Fair Value of Net Assets Acquired	<u>\$ 17,504</u>
Working capital acquired was estimated as follows:	
Production taxes payable	(9)
Total working capital	<u>\$ (9)</u>

Pro Forma Financial Information (Unaudited)

For the years ended December 31, 2017 and 2016, the following pro forma financial information represents the combined results for the Company and the properties acquired in June 2017 and in October 2016 as if the acquisitions and related financing had occurred on January 1, 2016. For purposes of the pro forma financial information, it was assumed that the June 2017 Acquisition was funded through cash. For purposes of the pro forma financial information, it was assumed that the October 2016 Acquisition was funded through the issuance of \$260.3 million in convertible preferred securities and borrowings under the revolving credit facility. The pro forma information includes the effects of adjustments for depletion, depreciation, amortization and accretion expense of \$1.6 million and \$23.1 million for the years ended December 31, 2017 and 2016, respectively. No pro forma adjustments were made for non-recurring transaction costs for the year ended December 31, 2017. The pro forma information includes the effects of a decrease in non-recurring transaction costs that are included in general and administrative expenses and acquisition transaction expenses of \$2.6 million for the year ended December 31, 2016. No pro forma adjustments were made for incremental interest expense on acquisition financing for the year ended December 31, 2017. The pro forma information includes the effects of adjustments for the incremental interest expense on acquisition financing of \$4.0 million for the year ended December 31, 2016. The pro forma information includes the effects of adjustments for income taxes of \$0.6 million for the year ended December 31, 2017. No pro forma adjustments were made for the effect of income taxes for the year ended December 31, 2016 as the acquisition occurred before the Corporate Reorganization. Additionally, the pro forma financial information excludes the effects the August 2016 Acquisition as these pro forma adjustments were de minimis.

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

	For the Year Ended	
	December 31,	
	2017	2016
Revenues	\$ 606,460	\$ 325,355
Net loss	\$ (44,231)	\$ (441,571)
Loss per share		
Basic and diluted	\$ (0.35)	\$ (1.54)

Note 5—Long-Term Debt

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

	As of December 31,	
	2018	2017
Credit facility due August 16, 2022 (or an earlier time as set forth below in the credit facility)	\$ 285,000	\$ 90,000
2021 Senior Notes due July 15, 2021	—	550,000
2024 Senior Notes due May 15, 2024	400,000	400,000
2026 Senior Notes due February 1, 2026	750,000	—
Unamortized debt issuance costs on Senior Notes	(17,341)	(16,639)
Total long-term debt	1,417,659	1,023,361
Less: current portion of long-term debt	—	—
Total long-term debt, net of current portion	\$ 1,417,659	\$ 1,023,361

Credit Facility

On September 4, 2014, Holdings entered into a credit facility with a syndicate of banks, which is subject to a borrowing base. In connection with the IPO and the merger of Holdings into the Company, the Company assumed all of the obligations of Holdings under the credit facility and became the borrower thereunder.

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) January 15, 2021 if (and only if) the Company's 2021 Senior Notes (as defined below) have not been refinanced or repaid in full on or prior to January 15, 2021, (c) 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 (d) the earlier termination in whole of the commitments. No principal payments are generally required until the credit agreement matures or in the event that the borrowing base falls below the outstanding balance.

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

In February 2018, the Company entered into a consent agreement and amended its revolving credit facility to (i) provide for consent by the lenders to (a) the designation of Elevation as an unrestricted subsidiary and (b) the transfer of certain

assets by the Company and one of the guarantors to such unrestricted subsidiary; and (ii) amend certain provisions of the credit agreement, including the incurrence of indebtedness covenant to permit certain indebtedness in connection with certain transportation service agreements with such unrestricted subsidiary.

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

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

In December 2018, the Company amended its revolving credit facility to increase the borrowing base from \$800.0 million to \$1.2 billion, associated with the postponed November 1, 2018 scheduled borrowing base determination. The current elected commitments remained at \$650.0 million.

In January 2019, the Company amended its revolving credit facility to permit prepayments and redemptions of the Company's unsecured bonds, subject to certain terms, conditions and financial thresholds.

As of December 31, 2018, the credit facility was subject to a borrowing base of \$1.2 billion, subject to current elected commitments of \$650.0 million. As of December 31, 2018, the Company had \$285.0 million of borrowings outstanding. As of December 31, 2017, the Company had \$90.0 million outstanding borrowings. As of December 31, 2018 and 2017, the Company had standby letters of credit of \$35.7 million and \$25.7 million, respectively, which reduce the availability of the undrawn borrowing base. At December 31, 2018, the undrawn balance under the credit facility was \$365.0 million. As of the date of this filing, the Company had \$285.0 million borrowings outstanding under the credit facility.

The amount available to be borrowed under the Company's revolving credit facility is subject to a borrowing base that is redetermined semiannually on each May 1 and November 1, 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. Additionally, the credit facility provides for a commitment fee of 0.375% to 0.50%, depending on borrowing base usage. The grid below shows the Base Rate Margin and Eurodollar Margin depending on the applicable Borrowing Base Utilization Percentage (as defined in the credit facility) as of the date of this filing:

Borrowing Base Utilization Grid

Borrowing Base Utilization Percentage	Utilization	LIBOR Margin	Base Rate Margin	Commitment Fee
Level 1	< 25	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 from hedging in excess of 85% of its anticipated production volumes.

The credit facility also contains financial covenants requiring the Company and its restricted subsidiaries to comply with a current ratio of its consolidated current assets (includes availability under the revolving credit facility and excludes

derivative assets) to its consolidated current liabilities (excludes the current portion of long-term debt and derivative liabilities), of not less than 1.0 to 1.0 and to maintain, on the last day of each quarter, a ratio of consolidated debt less cash balances to its consolidated EBITDAX (EBITDAX is defined as net income adjusted for certain cash and non-cash items including DD&A, exploration expense, gains/losses on derivative instruments, amortization of certain debt issuance costs, non-cash compensation expense, interest expense and prepayment premiums on extinguishment of debt) for the four fiscal quarter period most recently ended, not to exceed 4.0 to 1.0 as of the last day of such fiscal quarter. The Company was in compliance with all financial covenants under the credit facility as of December 31, 2018.

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

Second Lien Notes

On May 29, 2014, Holdings entered into a five year, \$430.0 million term loan facility with a syndicate of lenders (the "Second Lien Notes"). The Second Lien Notes would have matured on May 29, 2019. Holdings had drawn the full \$430.0 million under the Second Lien Notes that bore an average interest rate of approximately 10.7%. The interest rates were fixed and interest was payable semi-annually.

In July 2016, the Second Lien Notes were repaid and terminated in conjunction with the 2021 Senior Notes Offering. The Company used the proceeds from the 2021 Senior Notes (as discussed below) to repay the outstanding \$430.0 million of principal and a \$4.3 million prepayment penalty. The prepayment penalty was expensed during the year ended December 31, 2016 in the consolidated statements of operations within the interest expense line item. Additionally, during the year ended December 31, 2016, the Company wrote off approximately \$15.1 million of unamortized debt discount and debt issuance costs that were related to the Second Lien Notes. The write off of the unamortized debt discount and debt issuance costs were recorded in the consolidated statements of operations within the interest expense line item.

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 Notes Offering, 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 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, 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 includes 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 commencing on November 15, 2017. The Company received net proceeds of approximately \$392.6 million after deducting discounts and 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 its current subsidiaries and by certain future restricted

subsidiaries that guarantees its indebtedness under a credit facility (the “2024 Senior Note Guarantors”). The 2024 Senior 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 2024 Senior 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. The Company was in compliance with all financial covenants under the 2024 Senior Notes Indenture as of December 31, 2018.

2026 Senior Notes

In January 2018, the Company closed a private offering of its 2026 Senior Notes (the “2026 Senior Notes” and the offering, the “2026 Senior Notes Offering”) that resulted in net proceeds of approximately \$737.9 million after deducting discounts and fees. The Company used \$534.2 million of the net proceeds from the 2026 Senior Notes Offering to tender 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 bear interest at an annual rate of 5.625%. Interest on the Company's 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. The Company's 2026 Senior Notes will mature on February 1, 2026.

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 any of the Company's future 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 2024 Senior Notes may declare all outstanding 2026 Senior Notes to be due and payable immediately. The Company was in compliance with all financial covenants under the 2026 Senior Notes Indenture as of December 31, 2018.

Debt Discount Costs on Second Lien Notes

The Company's Second Lien Notes were issued with an original issue discount (OID) of \$6.5 million. In July 2016, the Company repaid the Second Lien Notes in full and accelerated the remaining unamortized balance of \$4.3 million. This expense was recorded in the consolidated statements of operations within the interest expense line item. As of December 31, 2017, there was no remaining balance on the OID.

Debt Issuance Costs

As of December 31, 2018 and 2017, the Company had debt issuance costs net of accumulated amortization of \$3.3 million and \$3.8 million, respectively, related to its credit facility which has been reflected on the Company's consolidated balance sheet within the line item other non-current assets. As of December 31, 2018, the Company had debt issuance costs net of accumulated amortization of \$17.3 million related to its 2024 and 2026 Senior Notes (collectively, the "Senior Notes"), and as of December 31, 2017, the Company had debt issuance costs net of accumulated amortization of \$16.6 million related to its 2021 and 2024 Senior Notes, which has been reflected on the Company's consolidated balance sheet within the line item Senior Notes, net of unamortized debt issuance costs. Upon the repayment of the Company's Second Lien Notes in July 2016, the Company accelerated the amortization of the remaining \$10.8 million of unamortized debt issuance costs. As of December 31, 2018 and 2017, there was no remaining balance on debt issuance costs associated with the Second Lien Notes. Upon the redemption of the Company's 2021 Senior Notes in January and February 2018, the Company accelerated the amortization of the remaining \$9.4 million of unamortized debt issuance costs. These expenses were recorded in the consolidated statements of operations within the interest expense line item. Debt issuance costs include origination, legal, engineering, and other fees incurred in connection with the Company's credit facility and Senior Notes. For the years ended December 31, 2018, 2017, and 2016, the Company recorded amortization expense related to the debt issuance costs of \$13.2 million, \$4.3 million and \$14.4 million, respectively.

Interest Incurred on Long-Term Debt

For the years ended December 31, 2018, 2017 and 2016, the Company incurred interest expense on long-term debt of \$82.7 million, \$58.7 million and \$50.5 million, respectively, and capitalized interest of \$8.2 million, \$11.1 million and \$5.2 million, respectively, for the years ended December 31, 2018, 2017 and 2016. Included in interest expense for the year ended December 31, 2018 is a make-whole premium of \$35.6 million related to the Company's redemption of its 2021 Senior Notes in January and February 2018. Also included in interest expense for the year ended December 31, 2017 is a prepayment penalty of \$4.3 million related to the Company's repayment of its Second Lien Notes in July 2016.

Senior Note Repurchase Program

On January 4, 2019, the Board of Directors authorized a program, subject to the amendment to the Company's revolving credit facility, to repurchase up to \$100.0 million of the Company's Senior Notes. The Company's Senior Notes Repurchase Program does not obligate it to acquire any specific nominal amount of Senior Notes. As of the date of this filing, the Company has repurchased 2026 Senior Notes with a nominal value of \$13.1 million for \$10.5 million in connection with the Senior Notes Repurchase Program.

Note 6—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 eleven counterparties, all of whom are lenders under our credit agreement. The Company has netting arrangements with the counterparties that provide for the offset of payables against receivables from separate derivative arrangements with the counterparties in the event of contract termination. The derivative contracts may be terminated by a non-defaulting party in the event of default by one of the parties to the agreement. There are no credit-risk-related contingent features or circumstances in which the features could be triggered in derivative instruments that are in a net liability position at the end of the reporting period.

The Company's commodity derivative contracts as of December 31, 2018 are summarized below:

	2019	2020
NYMEX WTI Crude Swaps:		
Notional volume (Bbl)	900,000	1,200,000
Weighted average fixed price (\$/Bbl)	\$ 52.56	\$ 52.66
NYMEX WTI Crude Sold Calls:		
Notional volume (Bbl)	11,700,000	1,800,000
Weighted average sold call price (\$/Bbl)	\$ 65.40	\$ 67.53
NYMEX WTI Crude Sold Puts:		
Notional volume (Bbl)	13,500,000	1,800,000
Weighted average sold put price (\$/Bbl)	\$ 41.27	\$ 42.00
NYMEX WTI Crude Purchased Puts:		
Notional volume (Bbl)	17,850,000	1,800,000
Weighted average purchased put price (\$/Bbl)	\$ 47.67	\$ 50.00
NYMEX HH Natural Gas Swaps:		
Notional volume (MMBtu)	32,400,000	—
Weighted average fixed price (\$/MMBtu)	\$ 2.81	—
NYMEX HH Natural Gas Purchased Puts:		
Notional volume (MMBtu)	3,600,000	—
Weighted average purchased put price (\$/MMBtu)	\$ 3.04	—
NYMEX HH Natural Gas Sold Calls:		
Notional volume (MMBtu)	3,600,000	—
Weighted average sold call price (\$/MMBtu)	\$ 3.46	—
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)	36,000,000	—
Weighted average fixed basis price (\$/MMBtu)	\$ (0.75)	—

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

Location on Balance Sheet	As of December 31, 2018				
	Gross Amounts of Recognized Assets and Liabilities	Gross Amounts Offset in the Balance Sheet ⁽¹⁾	Net Amounts of Assets and Liabilities Presented in the Balance Sheet	Gross Amounts not Offset in the Balance Sheet ⁽²⁾	Net Amounts ⁽³⁾
Current assets ⁽⁴⁾	\$ 115,852	\$ (66,945)	\$ 48,907	\$ (192)	\$ 57,147
Non-current assets	\$ 17,217	\$ (8,785)	\$ 8,432	\$ —	\$ —
Current liabilities ⁽⁴⁾	\$ (67,141)	\$ 66,945	\$ (196)	\$ 192	\$ (4)
Non-current liabilities	\$ (8,785)	\$ 8,785	\$ —	\$ —	\$ —

As of December 31, 2017

Location on Balance Sheet	Net Amounts of				
	Gross Amounts of Recognized Assets and Liabilities	Gross Amounts Offset in the Balance Sheet ⁽¹⁾	Assets and Liabilities Presented in the Balance Sheet	Gross Amounts not Offset in the Balance Sheet ⁽²⁾	Net Amounts ⁽³⁾
Current assets	\$ 22,118	\$ (17,986)	\$ 4,132	\$ —	\$ 4,132
Non-current assets	\$ 13,686	\$ (13,686)	\$ —	\$ —	\$ —
Current liabilities	\$ (85,414)	\$ 17,986	\$ (67,428)	\$ —	\$ (84,702)
Non-current liabilities	\$ (30,960)	\$ 13,686	\$ (17,274)	\$ —	\$ —

- (1) Agreements are in place with all of the Company's financial trading counterparties that allow for the financial right of offset for derivative assets and derivative liabilities at settlement or in the event of a default under the agreements.
- (2) Netting for balance sheet presentation is performed by current and non-current classification. This adjustment represents amounts subject to an enforceable master netting arrangement, which are not netted on the balance sheet. There are no amounts of related financial collateral received or pledged.
- (3) Net amounts are not split by current and non-current. All counterparties in a net asset position are shown in the current asset line item and all counterparties in a net liability position are shown in the current liability line item.
- (4) 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 loss for the years ended December 31, 2018, 2017 and 2016 (in thousands). Commodity derivatives loss are included under other income (expense).

	For the Year Ended December 31,		
	2018	2017	2016
Commodity derivatives loss	\$ (8,554)	\$ (36,332)	\$ (100,947)

Note 7—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 periods indicated (in thousands):

	For the Year Ended December 31,	
	2018	2017
Balance beginning of period	\$ 69,540	\$ 56,108
Liabilities incurred or acquired	2,136	9,802
Liabilities settled	(13,869)	(4,169)
Revisions in estimated cash flows	6,800	2,630
Accretion expense	5,184	5,169
Balance end of period	<u>\$ 69,791</u>	<u>\$ 69,540</u>

Note 8—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 December 31, 2018 and December 31, 2017 by level within the fair value hierarchy (in thousands):

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

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

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

Commodity Derivative Instruments

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

Fair Value of Financial Instruments

The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable, accounts payable, commodity derivative instruments (discussed above) and long-term debt. The carrying values of cash and cash equivalents, accounts receivable and accounts payable are representative of their fair values due to their short-term maturities. The carrying amount of the Company's credit facility approximated fair value as it bears interest at variable rates over the term of the loan. The fair value of the 2021 Senior Notes, 2024 Senior Notes and 2026 Senior Notes (collectively, the "Senior Notes") was derived from available market data. As such, the Company has classified the Senior Notes as Level 2. Please refer to *Note 5 — 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 December 31, 2018		At December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Credit facility	\$ 285,000	\$ 285,000	\$ 90,000	\$ 90,000
2021 Senior Notes ⁽¹⁾	\$ —	\$ —	\$ 540,382	\$ 583,000
2024 Senior Notes ⁽²⁾	\$ 393,866	\$ 330,000	\$ 392,979	\$ 427,000
2026 Senior Notes ⁽³⁾	\$ 738,793	\$ 558,750	\$ —	\$ —

- (1) The carrying amount of the 2021 Senior Notes includes unamortized debt issuance costs of \$9.6 million as of December 31, 2017. There were no unamortized debt issuance costs as of December 31, 2018.
- (2) The carrying amount of the 2024 Senior Notes includes unamortized debt issuance costs of \$6.1 million and \$7.0 million as of December 31, 2018 and 2017, respectively.
- (3) The carrying amount of the 2026 Senior Notes includes unamortized debt issuance costs of \$11.2 million as of December 31, 2018. There were no unamortized debt issuance costs as of December 31, 2017.

Non-Recurring Fair Value Measurements

The Company applies the provisions of the fair value measurement standard on a non-recurring basis to its non-financial assets and liabilities, including proved property and goodwill. These assets and liabilities are not measured at fair

value on a recurring basis, but are subject to fair value adjustments when facts and circumstances arise that indicate a need for measurement.

The Company utilizes fair value on a non-recurring basis to review its proved oil and gas properties for potential impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such property. The Company uses an income approach analysis based on the net discounted future cash-flows of producing property. The future cash-flows are based on Management's estimates for the future. Unobservable inputs included future estimates of oil and gas production, as the case may be, from the Company's reserve reports, commodity prices based on the sales contract terms or forward price curves, operating and development costs, and a discount rate based on a market-based weighted average cost of capital (all of which are Level 3 inputs within the fair value hierarchy). For the years ended December 31, 2018 and 2016, the Company recognized \$16.2 million and \$22.5 million in impairment expense on proved oil and gas properties, respectively. The impairment expense for the years ended December 31, 2018 and 2016 is related to impairment of the assets in the Company's northern field. The future undiscounted cash flows did not exceed its carrying amount associated with its proved oil and gas properties in the Company's northern field. A portion of the net book value of these proved oil and gas properties were impaired at September 30, 2018 and the proved oil and gas properties in the northern field were written down to their fair value. The full net book value of these proved oil and gas properties were impaired at June 30, 2016 as it was determined that the proved oil and gas properties had no remaining fair value. No impairment expense was recognized for the year ended December 31, 2017 on proved oil and gas properties.

The Company applies the provisions of ASC 350, *Intangibles-Goodwill and Other*. Goodwill represents the excess of the purchase price over the estimated value of the net assets acquired in business combinations. The Company tests goodwill for impairment annually on September 30, or whenever other circumstances or events indicate that the carrying amount of goodwill may not be recoverable. The goodwill test is performed at the reporting unit level, which represents the Company's oil and gas operations in its core DJ Basin field. If indicators of impairment are determined to exist, an impairment charge is recognized if the carrying value of goodwill exceeds its implied fair value. Any sharp prolonged decreases in the prices of oil and natural gas as well as continued declines in the quoted market price of the Company's common shares could change the estimates of the fair value of the reporting unit and could result in an impairment charge. The Company performed a quantitative assessment as of September 30, 2018, which concluded the fair value of the reporting unit was greater than its carrying amount. The Company identified triggering events as of December 31, 2018, due to the decrease in commodity pricing and the quoted market price of the Company's common shares compared to September 30, 2018. As such, the Company performed a quantitative assessment as of December 31, 2018, utilizing an income approach based on estimates of the expected discounted future cash flows of the reporting unit's oil and gas properties, which concluded the fair value of the reporting unit was not greater than its carrying amount. As a result, the Company recorded goodwill impairment of \$54.2 million, the entirety of the balance, for the year ended December 31, 2018. The Company performed a quantitative assessment as of September 30, 2017, which concluded the fair value of the reporting unit was greater than its carrying amount. The Company performed a qualitative assessment as of December 31, 2017 and 2016, which concluded the fair value of the reporting unit was more-likely-than-not greater than its carrying amount.

The Company's other non-recurring fair value measurements include the purchase price allocations for the fair value of assets and liabilities acquired through business combinations, please refer to *Note 4 — Acquisitions and Divestitures*. The fair value of assets and liabilities acquired through business combinations is calculated using a discounted-cash flow approach using level 3 inputs. Cash flow estimates require forecasts and assumptions for many years into the future for a variety of factors, including risk-adjusted oil and gas reserves, commodity prices, development costs, and operating costs, based on market participant assumptions. The fair value of assets or liabilities associated with purchase price allocations is measured on a non-recurring basis and is not measured in periods after initial recognition.

Note 9—Equity

Stock Repurchase Program

On November 19, 2018, the Company announced the Board of Directors had authorized a program to repurchase up to \$100.0 million of the Company's common stock ("Stock Repurchase Program"). During the year ended December 31, 2018, the Company repurchased 4.1 million shares of its common stock for \$26.2 million, at a weighted average per share price of \$6.47 per share, in connection with the Stock Repurchase Program. The Company's Stock Repurchase Program does not obligate it to acquire any specific number of shares and will expire on March 31, 2019. The Company intends to conduct any open market stock repurchase activities in compliance with the safe harbor provisions of Rule 10b-18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act").

Preferred Units

On July 3, 2018, Elevation Midstream, LLC (“Elevation”), a Delaware limited liability company and subsidiary of the Company, entered into a securities purchase agreement (the “Securities Purchase Agreement”) with a third party (the “Purchaser”), pursuant to which Elevation agreed to sell 150,000 Preferred Units (the “Elevation Preferred Units”) of Elevation at a price of \$990 per Elevation Preferred Unit with an aggregate liquidation preference of \$150.0 million (the “Private Placement”), in a transaction exempt from the registration requirements under the Securities Act of 1933, as amended (the “Securities Act”). The Private Placement closed on July 3, 2018 (the “Preferred Unit Closing Date”), funded on July 19, 2018 and resulted in net proceeds of approximately \$141.9 million, \$25.4 million of which was a reimbursement for previously incurred midstream capital expenditures and general and administrative expenses. These Preferred Units are non-recourse to Extraction and represent the noncontrolling interest presented on the consolidated balance sheets, consolidated statement of operations and consolidated statement of changes in members' and stockholders' equity and noncontrolling interest. 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 December 31, 2018, \$136.9 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. As of December 31, 2018 and 2017, Elevation capital expenditures represented all of the gathering systems and facilities line item in the consolidated balance sheet and the gathering systems and facilities additions in the consolidated statement of cash flows.

During the twenty-eight months following the Preferred Unit Closing Date (the “Preferred Unit Commitment Period”), subject to the satisfaction of certain financial and operational metrics and certain other customary closing conditions, Elevation has the right to require the Purchaser to purchase additional Elevation Preferred Units on the terms set forth in the Securities Purchase Agreement. Elevation may require the Purchaser to purchase additional Elevation Preferred Units, in increments of at least \$25.0 million, up to an aggregate amount of \$350.0 million. During the Preferred Unit Commitment Period, Elevation is required to pay the Purchaser a quarterly commitment fee payable in cash or in kind of 1.0% per annum on any undrawn amounts of such additional \$350.0 million commitment. Elevation recognized \$1.8 million of commitment fees paid-in-kind for the year ended December 31, 2018, included under the Preferred Unit commitment fees and dividends paid-in-kind line item in the consolidated statement of changes in members' and stockholders' equity and noncontrolling interest. No such fees were recognized for the year ended December 31, 2017 or 2016.

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, such dividend is payable in cash or in kind at the election of Elevation. After June 30, 2020, such dividend is payable solely in cash. Elevation recognized \$5.5 million of dividends paid-in-kind for the year ended December 31, 2018, included under the Preferred Unit commitment fees and dividends paid-in-kind line item in the consolidated statement of changes in members' and stockholders' equity and noncontrolling interest. No such fees were recognized for the years ended December 31, 2017 or 2016.

Private Placement of Common Stock

On December 15, 2016, the Company completed the issuance of 25.0 million shares of common stock, at a price of \$18.25 per share, in connection with the Private Placement (the “Private Placement”). The Private Placement resulted in approximately \$457.0 million of gross proceeds and approximately \$441.9 million of net proceeds, after deducting placement agent commissions and offering expenses. Proceeds from the Private Placement were to be used for general corporate purposes, including to fund the Company's 2017 capital expenditures.

Initial Public Offering

On October 17, 2016, the Company completed its initial public offering, issuing 38.3 million shares of common stock, par value \$0.01 per share (“common stock”), which included the full exercise of the underwriters' over-allotment option of 5.0 million shares at a price of \$19.00 per share. The net proceeds of the offering were \$681.0 million, after deducting underwriting discounts and commissions and offering expenses, of approximately \$47.3 million. The proceeds from the Offering were used to (i) redeem in full the Series A Preferred Units for \$90.0 million and (ii) to repay borrowings under the Company's revolving credit facility for \$291.6 million. The remaining net proceeds were to be used for general corporate purposes, including to fund 2017 capital expenditures. The material terms of the Offering are described in the Company's final prospectus, dated October 11, 2016 and filed with the SEC pursuant to Rule 424(b)(4) of the Securities Act of 1933, as amended, on October 13, 2016.

Series A Preferred Units

On October 3, 2016, the Company issued \$75.0 million in Series A Preferred Units (the “Series A Preferred Units”) to fund a portion of the purchase price for the October 2016 Acquisition. The Series A Preferred Units were entitled to receive a cash dividend of 10% per year, payable quarterly in arrears. All holders of Series A Preferred Units were also members of Holdings. The Company used \$90.0 million of the net proceeds from its IPO to redeem the Series A Preferred Units in full on October 17, 2016, including a premium of \$15.0 million which is recorded within additional paid in capital in the consolidated statement of changes in members' and stockholders' equity and noncontrolling interest. For further discussion on the October 2016 Acquisition, please refer to *Note 4 — Acquisitions and Divestitures*.

Series A Preferred Stock and Series B Preferred Units

On October 3, 2016, the Company issued \$185.3 million in convertible preferred securities ("Series B Preferred Units") to fund a portion of the purchase price for the October 2016 Acquisition. The Series B Preferred Units were entitled to receive a cash dividend of 10% per year, payable quarterly in arrears, and the Company had the ability to pay up to 50% of the quarterly dividend in kind. For the year ended December 31, 2016, the Company paid \$0.7 million of dividends associated with the Series B Preferred Units. The Company did not make any payments in kind on the Series B Preferred Units from the date of issuance of the Series B Preferred Units through the Offering. The Series B Preferred Units converted in connection with the closing of the IPO into 185,280 shares of Series A Convertible Preferred Stock (the "Series A Preferred Stock") that are entitled to receive a cash dividend of 5.875% per year, payable quarterly in arrears, and the Company has the ability to pay such quarterly dividends in kind at a dividend rate of 10% per year (decreased proportionately to the extent such quarterly dividends are paid in cash). For the year ended December 31, 2018, the Company accrued \$2.7 million of dividends associated with the Series A Preferred Stock, or \$14.69 per share, which were paid in January 2019. The Company did not make any payments in kind on the Series A Preferred Stock from the date of the Offering through December 31, 2017. Beginning on or after the later of (a) 90 days after the closing of the Offering and (b) the earlier of 120 days after the closing of the Offering and the expiration of the lock-up period contained in the underwriting agreement entered into in connection with the Offering ("Lock-Up Period End Date"), the Series A Preferred Stock will be convertible into shares of the Company's common stock at the election of the holders of the Series A Preferred Stock ("Series A Preferred Holders") at a conversion ratio per share of Series A Preferred Stock of 61.9195. Beginning on or after the Lock-Up Period End Date until the three year anniversary of the closing of the Offering, the Company may elect to convert the Series A Preferred Stock at a conversion ratio per share of Series A Preferred Stock of 61.9195, but only if the closing price of the Company's common stock trades at or above a certain premium to the Company's initial offering price, such premium to decrease with time. In accordance with ASC Topic 470, *Debt* ("ASC 470"), the Company determined that the conversion feature of the Series A Preferred Stock represented a beneficial conversion feature. The fair value of the Company's common stock on the closing of the IPO was greater than the Series A Preferred Stock conversion price by approximately \$32.7 million in aggregate. Under ASC 470, \$32.7 million (the fair value of the beneficial conversion feature) of the proceeds received from the issuance of the Series B Preferred Units, subsequently converted to the Series A Preferred Stock, was allocated to additional paid-in capital. The beneficial conversion feature is required to be accreted on a non-cash basis over the approximate 60 month period between the issuance date and the required redemption date of October 15, 2021, or fully accreted upon an accelerated date of redemption or conversion, resulting in an increase of the Series A Convertible Preferred Stock presented on the Consolidated Balance Sheets. The accretion of the beneficial conversion feature of Series A Preferred Stock is presented as a decrease to additional paid-in capital on the changes in members' and stockholders' equity and noncontrolling interest. As a result, approximately \$6.0 million and \$5.4 million was accreted during the years ended December 31, 2018 and 2017. In certain situations, including a change of control, the Series A Preferred Stock may be redeemed for cash in an amount equal to the greater of (i) 135% of the liquidation preference of the Series A Preferred Stock and (ii) a 17.5% annualized internal rate of return on the liquidation preference of the Series A Preferred Stock. The Series A Preferred Stock mature on October 15, 2021, at which time they are mandatorily redeemable for cash at the liquidation preference.

Note 10—Income Taxes

On December 22, 2017, the Tax Cuts and Jobs Act (the “TCJA”) was enacted making significant changes to the Internal Revenue Code. Many of the provisions in the TCJA have an effective date for years beginning after December 31, 2017, including the lowering of the U.S. corporate rate from 35 percent to 21 percent. As a result, the Company was required to remeasure the deferred tax assets and liabilities as of December 31, 2017 at the rate in which they are expected to reverse. This re-measurement of deferred tax assets and liabilities required the Company to analyze and record a one-time adjustment to reduce the overall deferred tax liability in the consolidated balance sheets and reflect a corresponding income tax benefit in the consolidated statements of operations for the year ended December 31, 2017. This resulted in the recording of an income tax benefit of \$23.4 million, as well as a corresponding reduction in the deferred tax liability as of December 31, 2017.

During the third quarter of 2018, we completed the accounting for the income tax effect of the TCJA's limit on compensation under Internal Revenue Code Sec. 162(m) and stock-based compensation for covered employees. This resulted in a \$0.4 million reduction in deferred tax assets that had been recorded as a provisional amount as of December 31, 2017. The Company believes the accounting is complete regarding the revaluation of the deferred tax balances and there are no remaining provisional amounts associated with the TCJA as of December 31, 2018. The Company is aware that the Internal Revenue Service has issued proposed regulations regarding the TCJA and has incorporated this guidance into its current tax policy. The Company will continue to monitor and analyze the impact of future guidance and any final regulations as they become available.

The components of the income tax expense (benefit) were as follows (in thousands):

	For the Year Ended December 31,	
	2018	2017
Current:		
Federal	\$ —	\$ —
State, net of federal benefit	—	—
Total current income tax expense (benefit)	\$ —	\$ —
Deferred:		
Federal	\$ 56,943	\$ (61,719)
State, net of federal benefit	9,907	(1,981)
Total deferred income tax expense (benefit)	\$ 66,850	\$ (63,700)
Income tax expense (benefit)	<u>\$ 66,850</u>	<u>\$ (63,700)</u>

The following table reconciles the income tax expense (benefit) with income tax expense at the federal statutory rate (in thousands):

	For the Year Ended December 31,	
	2018	2017
Net income (loss) before income taxes	\$ 188,705	\$ (108,108)
Federal income taxes at statutory rate	39,628	(37,838)
Impact of goodwill impairment	11,386	—
State income taxes, net of federal benefit	9,907	(3,118)
Nondeductible stock-based compensation	5,088	2,264
Enactment of the Tax Cuts and Jobs Act	—	(23,412)
Other	841	(1,596)
Income tax expense (benefit)	<u>66,850</u>	<u>(63,700)</u>
Net income (loss)	<u>\$ 121,855</u>	<u>\$ (44,408)</u>

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities were as follows (in thousands):

	As of December 31,	
	2018	2017
Deferred Tax Assets:		
Net operating loss carryforward	\$ 149,399	\$ 205,806
Commodity derivatives	—	19,984
Stock-based compensation	17,242	13,853
Intangible drilling costs - Section 59(e)	127,604	—
Property taxes	22,277	12,667
Other	10,856	4,386
Total deferred tax assets	<u>\$ 327,378</u>	<u>\$ 256,696</u>
Deferred Tax Liabilities:		
Excess basis of oil and gas properties	\$ (426,428)	\$ (299,022)
Commodity derivatives	(10,126)	—
Total deferred tax liabilities	<u>(436,554)</u>	<u>(299,022)</u>
Deferred Tax Liability, net	<u><u>\$ (109,176)</u></u>	<u><u>\$ (42,326)</u></u>

Management considers whether some portion or all of the deferred tax assets will be realized based on a more likely than not standard of judgment. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making this assessment. The Company has net operating loss carryforwards (NOLs) for U.S. income tax purposes that have been generated from the Company's operations in 2017 of approximately \$605.9 million, which expire in 2037 and are not subject to the 80 percent limitation of taxable income. As of December 31, 2018, the Company also had \$517.5 million of indirect drilling costs that were capitalized under Code Section 59(e). As of December 31, 2017, the Company had no indirect drilling costs that were capitalized under Code Section 59(e).

The utilization of such NOL carryforwards may be limited upon the occurrence of certain ownership changes as stipulated in Section 382 of the Internal Revenue Code of 1986, as amended (the "Code"). As of December 31, 2018, the Company determined that the statutory provision of Section 382 will not limit the Company's ability to realize future tax benefits. As of December 31, 2018, the Company believes it will be able to generate sufficient future taxable income and accordingly, believes that it is more likely than not that its deferred income tax assets will be fully realized. The Company files income tax returns in the U.S. federal jurisdiction and in Colorado. The statute of limitations related to the 2016 and 2017 tax returns are open through 2020 and 2021 respectively, however, the ability for the tax authority to adjust the NOL will continue until three years after the NOL is utilized.

As of December 31, 2018, the Company believes that it has no liability for uncertain tax positions. If the Company were to determine there were any uncertain tax positions, the Company would recognize the liability and related interest and penalties within income tax expense. As of December 31, 2018, the Company had no provision for interest or penalties related to uncertain tax positions.

Note 11—Unit and Stock-Based Compensation

Extraction Long Term Incentive Plan

In October 2016, the 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 accordance with the terms of the LTIP, 20.2 million shares of common stock have been reserved for issuance pursuant to awards under the LTIP. Extraction has granted awards under the LTIP to certain directors, officers and employees, including stock options, restricted stock units and performance stock awards.

Restricted Stock Units ("RSUs")

Restricted stock units granted under the LTIP ("RSUs") vest over either (i) a one-year service period, with 100% of the units vesting at the end of the service period, or (ii) a three-year service period with 25%, 25% and 50% of the units vesting in year one, two and three, respectively. Grant date fair value was determined based on the value of Extraction's common stock on the date of issuance. The Company assumed a forfeiture rate of zero as part of the grant date estimate of compensation cost. As of January 1, 2017, the Company elected to account for stock-based compensation forfeitures as they occur, as a result of the adoption of ASU No. 2016-09.

The Company recorded \$27.9 million, \$31.8 million and \$5.5 million of stock-based compensation costs related to RSUs for the years ended December 31, 2018, 2017 and 2016, respectively. As of December 31, 2018, there was \$32.2 million of total unrecognized compensation cost related to the unvested RSUs granted to certain employees that is expected to be recognized over a weighted average period of 1.4 years.

The following table summarizes the RSU activity from January 1, 2016 through December 31, 2018 and provides information for RSUs outstanding at the dates indicated.

	Number of Shares	Weighted Average Grant Date Fair Value
Non-vested RSUs at January 1, 2016	—	\$ —
Granted	3,237,500	\$ 21.41
Forfeited	—	\$ —
Vested	—	\$ —
Non-vested RSUs at December 31, 2016	3,237,500	\$ 21.41
Granted	1,369,083	\$ 16.37
Forfeited	(445,366)	\$ 19.85
Vested	(1,254,744)	\$ 20.85
Non-vested RSUs at December 31, 2017	2,906,473	\$ 19.51
Granted	1,226,768	\$ 12.53
Forfeited	(95,725)	\$ 14.94
Vested	(935,181)	\$ 19.44
Non-vested RSUs at December 31, 2018	3,102,335	\$ 16.91

Stock Options

Expense on the stock options are recognized on a straight-line basis over the service period of the award less awards forfeited. The fair value of the stock options 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 issues new shares.

The Company recorded \$15.1 million, \$15.7 million and \$2.9 million of stock-based compensation costs related to the stock options for the years ended December 31, 2018, 2017 and 2016, respectively. As of December 31, 2018, there was \$12.1 million of unrecognized compensation cost related to the stock options that is expected to be recognized over a weighted-average period of 0.8 years.

The following table summarizes the assumptions used for the Black-Scholes valuation model to calculate the stock-based compensation expense for the years ended December 31, 2017 and 2016. No stock options were granted for the year ended December 31, 2018.

	For the Year Ended	
	December 31, 2017	December 31, 2016
Risk free rates	2.0%	1.4%
Dividend yield	—	—
Expected volatility	58.9%	47.2%
Expected term (in years)	6.0	6.0

The weighted average fair value at the date of grant for stock options granted is as follows:

Weighted average per share	\$	8.66	\$	8.75
Total options granted		744,428		4,500,000
Total weighted average fair value of options granted (in thousands)	\$	6,445	\$	39,375

The following table summarizes the stock option activity from January 1, 2016 through December 31, 2018 and provides information for stock options outstanding at the dates indicated.

	Number of Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value (thousands)
Non-vested Stock Options at January 1, 2016	—	\$ —	\$ —
Granted	4,500,000	\$ 19.00	\$ 11,295
Forfeited	—	\$ —	\$ —
Vested	—	\$ —	\$ —
Non-vested Stock Options at December 31, 2016	4,500,000	\$ 19.00	\$ 4,680
Granted	744,428	\$ 15.53	\$ —
Forfeited	—	\$ —	\$ —
Vested	(1,748,138)	\$ 18.52	\$ —
Non-vested Stock Options at December 31, 2017	3,496,290	\$ 18.50	\$ —
Granted	—	\$ —	\$ —
Forfeited	—	\$ —	\$ —
Vested	(1,748,142)	\$ 18.49	\$ —
Non-vested Stock Options at December 31, 2018	<u>1,748,148</u>	\$ 18.50	\$ —

The following table summarizes information about outstanding and exercisable stock options as of December 31, 2018.

Outstanding Options				Exercisable Options		
Options	Weighted-Average	Weighted-Average		Options	Weighted-Average	Aggregate
	Remaining Contractual Life	Exercise Price	Intrinsic Value		Exercise Price per Share	Intrinsic Value
4,500,000	7.9 years	\$ 19.00	\$ —	3,000,000	\$ 19.00	\$ —
744,428	8.8 years	\$ 15.53	\$ —	496,280	\$ 15.53	\$ —
5,244,428	8.0 years	\$ 18.50	\$ —	3,496,280	\$ 18.50	\$ —

Performance Stock Awards

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

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

The assumptions used in valuing the PSAs granted were as follows:

	For the Year Ended December 31, 2018	For the Year Ended December 31, 2017
Risk free rates	2.3%	1.5%
Dividend yield	—	—
Expected volatility	59.9%	45.0%

The Company recorded \$5.7 million and \$0.8 million of stock-based compensation costs related to PSAs for the years ended December 31, 2018 and 2017, respectively. The Company did not record any stock-based compensation expense related to PSAs for the year ended December 31, 2016. As of December 31, 2018, there was \$9.1 million of unrecognized compensation cost related to the PSAs that is expected to be recognized over a weighted-average period of 1.7 year.

The following table summarizes the PSA activity from January 1, 2017 through December 31, 2018 and provides information for PSAs outstanding at the dates indicated.

	Number of Shares ⁽¹⁾	Weighted Average Grant Date Fair Value
Non-vested PSAs as of January 1, 2017	—	\$ —
Granted	832,163	\$ 8.85
Forfeited	—	\$ —
Vested	—	\$ —
Non-vested PSAs as of December 31, 2017	832,163	\$ 8.85
Granted	1,961,920	\$ 9.06
Forfeited	—	\$ —
Vested	—	\$ —
Non-vested PSAs as of December 31, 2018	<u>2,794,083</u>	<u>\$ 9.00</u>

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

Incentive Restricted Stock Units ("Incentive RSUs")

Officers of the Company contributed 2.7 million shares of common stock to Extraction Employee Incentive, LLC ("Employee Incentive"), which is owned solely by certain officers of the Company. Employee Incentive issued restricted stock units ("Incentive RSUs") to certain employees. Incentive RSUs vest over a three-year service period, with 25%, 25% and 50% of the units vesting in year one, two and three, respectively. On July 10, 2017, the partners of Employee Incentive amended the vesting schedule in which 25% vested on July 17, 2017 and the remaining Incentive RSUs will vest 25%, 25% and 25% each six months thereafter, over the remaining 18 months service period. Grant date fair value was determined based on the value of Extraction's common stock on the date of issuance. The Company assumed a forfeiture rate of zero as part of the grant date estimate of compensation cost. As of January 1, 2017, the Company elected to account for stock-based compensation forfeitures as they occur, as a result of the adoption of ASU No. 2016-09. As the vesting of any Incentive RSUs will be satisfied with shares of common stock that are already issued and outstanding, the Incentive RSUs do not have any impact on the Company's diluted earnings per share calculation.

The Company recorded \$19.6 million, \$17.3 million and \$2.4 million of stock-based compensation costs related to Incentive RSUs for the years ended December 31, 2018, 2017 and 2016, respectively. These costs were included in the consolidated statements of operations within the general and administrative expenses line item. As of December 31, 2018, there was \$0.9 million of total unrecognized compensation cost related to the unvested Incentive RSUs granted to certain employees that is expected to be recognized over a weighted average period of 0.1 years.

The following table summarizes the Incentive RSU activity from January 1, 2016 through December 31, 2018 and provides information for Incentive RSUs outstanding at the dates indicated.

	Number of Shares	Weighted Average Grant Date Fair Value
Non-vested Incentive RSUs at January 1, 2016	—	\$ —
Granted	2,717,968	\$ 20.45
Forfeited	(3,600)	\$ 20.45
Vested	—	\$ —
Non-vested Incentive RSUs at December 31, 2016	2,714,368	\$ 20.45
Granted	—	\$ —
Forfeited	(710,993)	\$ 20.45
Vested	(507,200)	\$ 20.45
Non-vested Incentive RSUs at December 31, 2017	1,496,175	\$ 20.45
Granted	—	\$ —
Forfeited	(41,400)	\$ 20.45
Vested	(978,775)	\$ 20.45
Non-vested Incentive RSUs at December 31, 2018	476,000	\$ 20.45

Holdings' Membership Unit Incentive Plan

On May 29, 2014, Holdings adopted the 2014 Membership Unit Incentive Plan ("2014 Plan"). The 2014 Plan provided for the compensation of employees, non-employee managers and consultants of the Company and its affiliates through grants of restricted unit awards ("Holdings' RUAs") and incentive units ("Holdings' Incentive Units"). The 2014 Plan was terminated as a result of the Corporate Reorganization in October 2016.

Holdings' RUAs

Holdings' RUAs vested over a three-year service period, with 25%, 25% and 50% of the units vesting in year one, two and three, respectively. The Company estimated fair value of the RUAs on their grant date based upon estimated volatility, market comparable risk free rate, estimated forfeiture rate and a discount for lack of marketability. Grant date fair value was determined based on the value of Holdings' Equity Units on the date of the grant. Due to a lack of historical data, the Company used the experience of other entities in the same industry to estimate a forfeiture rate. Expected forfeitures are then included as part of the grant date estimate of compensation cost.

No unit-based compensation costs related to Holdings' RUA grants were recorded for December 31, 2018 and 2017. The Company recorded \$16.8 million of unit-based compensation costs related to Holdings' RUA grants for the year ended December 31, 2016. These costs are included in the consolidated statements of operations within the general and administrative expenses line item. In connection with the Corporate Reorganization in 2016, the Holdings Membership Unit Incentive Plan ("2014 Plan") was terminated. As of December 31, 2018, there is no unrecognized compensation cost related to unvested RUAs granted to employees.

The following table summarizes the Holdings' RUA activity from January 1, 2016 through December 31, 2016 and provides information for Holdings' RUAs outstanding at the dates indicated.

	Number of Shares	Weighted Average Grant Date Fair Value
Non-vested RUAs at January 1, 2016	6,311,242	\$ 2.23
Granted	1,531,542	\$ 5.84
Forfeited	(181,817)	\$ 2.68
Vested	(7,660,967)	\$ 2.94
Non-vested RUAs at December 31, 2016	<u>—</u>	<u>\$ —</u>

PRL RUAs

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

No unit-based compensation costs related to PRL RUA grants were recorded for the year ended December 31, 2018 and 2017. The Company recorded \$0.5 million of unit-based compensation costs related to PRL RUA grants for the year ended December 31, 2016. These costs are included in the consolidated statements of operations within the general and administrative expenses line item. In connection with the Corporate Reorganization in 2016, the Holdings Membership Unit Incentive Plan ("2014 Plan") was terminated. As of December 31, 2018, there was no unrecognized compensation cost related to the PRL RUAs as all awards were fully vested.

Holdings' Incentive Units

In accordance with the 2014 Plan and the Holdings LLC Agreement, Holdings issued 3.0 million Holdings' incentive units to certain members of management in the fourth quarter of 2015. All of Holdings' Incentive Units were non-voting and subject to certain vesting and performance conditions. The Holdings' Incentive Units vested over a three year service period, with 25%, 25% and 50% of the units vesting in year 1, year 2 and year 3, respectively (with vesting between the first and third anniversaries occurring pro-rata based on the number of full months elapsed since the last vesting date), and in full upon a change of control, as defined in the Holdings LLC Agreement. The Holdings' Incentive Units were accounted for as liability awards under ASC 718, *Compensation-Stock Compensation*, with compensation expense based on period-end fair value.

In connection with the IPO, the Board of Managers of Holdings accelerated the vesting of the Holdings' Incentive Units. The Company's IPO and change of control triggered the conversion of these units into approximately 9.1 million common shares of the Company based on the 10-day volume weighted average price of the Company's common stock following its IPO as set forth in the Holdings Third Amended and Restated LLC Agreement. For the year ended December 31, 2016, the Company recognized approximately \$172.1 million in non-cash, stock-based compensation expense in connection with the conversion of the Holdings' Incentive Units into the Company's common stock. As of December 31, 2018 and 2017, there was no unrecognized compensation cost related to the Holdings' Incentive Units.

Note 12—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 available to common shareholders of the Company. The Company uses the "if-converted" method to determine potential dilutive effects of Series A Preferred Stock and the treasury method to determine the potential dilutive effects of outstanding restricted stock awards and stock options.

EPS for the year ended December 31, 2016 is calculated for the period from October 12, 2016, the effective date of the Corporate Reorganization, to December 31, 2016. EPS information is not applicable for reporting periods prior to the Corporate Reorganization. The basic weighted average shares outstanding calculation is based on the actual days in which the shares were

outstanding for the period from October 12, 2016 to December 31, 2016. Please refer to *Note 1 — Business and Organization* and *Note 9 — Equity* for additional discussion regarding the Corporate Reorganization.

The components of basic and diluted EPS were as follows:

	Year Ended December 31, 2018	Year Ended December 31, 2017	From October 12, 2016 to December 31, 2016
Basic and Diluted EPS (in thousands, except per share data)			
Net income (loss)	\$ 121,855	\$ (44,408)	\$ (226,107)
Less: Noncontrolling interest	(7,287)	—	—
Less: Adjustment to reflect Series A Preferred Stock dividend	(10,885)	(10,885)	(2,958)
Less: Adjustment to reflect accretion of Series A Preferred Stock discount	(5,984)	(5,394)	(1,041)
Net income (loss) available to common shareholders, basic and diluted	<u>\$ 97,699</u>	<u>\$ (60,687)</u>	<u>\$ (230,106)</u>
Weighted Average Common Shares Outstanding ^{(1) (2) (3)}			
Basic and diluted	174,748	171,910	149,029
Net Income (Loss) Allocated to Common Shareholders per Common Share			
Basic and diluted	\$ 0.56	\$ (0.35)	\$ (1.54)

- (1) For the year ended December 31, 2018, 3,102,335 potentially dilutive shares associated with restricted stock awards outstanding were not included in the calculation above, as they had an anti-dilutive effect on EPS. Additionally, 5,244,428 common shares for stock options were excluded as they were out-of-the-money and 11,472,445 common shares associated with the assumed conversion of Series A Preferred Stock were also excluded, as they would have had an anti-dilutive effect on EPS.
- (2) For the year ended December 31, 2017, 8,566,983 potentially dilutive shares were not included in the calculation above, as they had an anti-dilutive effect on EPS, including restricted stock awards, stock options outstanding and performance stock awards contingently issuable, if December 31, 2017 was the end of the measurement period. Additionally, the 11,472,445 common shares associated with the assumed conversion of Series A Preferred Stock were also excluded.
- (3) For the period of October 12 through December 31, 2016, 7,737,500 potentially dilutive shares were not included in the calculation above, as they had an anti-dilutive effect on EPS, including restricted stock awards and stock options outstanding for the period. Additionally, the 11,472,445 common shares associated with the assumed conversion of Series A Preferred Stock were also excluded.

Note 13—Commitments and Contingencies

Leases

The Company leases two office spaces in Denver, Colorado, two office spaces in Greeley, Colorado and one office space in Houston, Texas under separate operating lease agreements. The Denver, Colorado leases expire on February 29, 2020 and May 31, 2028, respectively. The Greeley and Houston leases expire on October 31, 2019, June 30, 2019 and January 31, 2022, respectively. Total rental commitments under non-cancelable leases for office space were \$32.8 million at December 31, 2018. The future minimum lease payments under these non-cancelable leases are as follows: \$3.5 million in 2019, \$3.4 million in 2020, \$3.4 million in 2021, \$3.4 million in 2022, \$3.4 million in 2023 and \$15.7 million thereafter. Rent expense was \$3.4 million, \$2.3 million, and \$1.9 million for the years ended December 31, 2018, 2017, and 2016, respectively.

On June 4, 2015, the Company subleased the remaining term of one of its Denver office leases that expires February 29, 2020. The sublease will decrease the Company's future lease payments by \$0.3 million.

Drilling Rigs

As of December 31, 2018, the Company was subject to commitments on three drilling rigs. In the event of early termination of these contracts, the Company would be obligated to pay an aggregate amount of approximately \$9.2 million as of December 31, 2018, as required under the terms of the contracts. In February 2016, the Company provided notice to terminate one of its drilling rigs that was subject to commitment at December 31, 2015. As part of this termination, the Company was obligated to pay \$1.0 million in the second quarter of 2016, which was recorded in the consolidated statements of operations within the other operating expenses line item. In January 2017, the Company provided notice for termination on one drilling rig and paid no termination fees.

Delivery Commitments

As of December 31, 2018, the Company's oil marketer is subject to a firm transportation agreement that commenced in November 2016 and has a ten-year term with a monthly minimum delivery commitment of 45,000 Bbl/d in year one, 55,800 Bbl/d in year two, 61,800 Bbl/d in years three through seven and 58,000 Bbl/d in years eight through ten. In May 2017, the Company amended its agreement with its oil marketer that requires it to sell all of its crude oil from an area of mutual interest in exchange for a make-whole provision that allows the Company to satisfy any minimum volume commitment deficiencies incurred by its oil marketer with future barrels of crude oil in excess of their minimum volume commitment through October 31, 2018. In December 2017, the Company extended the term of this agreement through October 31, 2019 and has posted a letter of credit in the amount of \$35.0 million. The Company is currently in the process of amending and extending this agreement. The Company evaluates its contracts for loss contingencies and accrues for such losses, if the loss can be reasonably estimated and deemed probable. The Company also has two long-term crude oil gathering commitments with an unconsolidated subsidiary, in which the Company has a minority ownership interest. The first agreement commenced in November 2016 and has a term of ten years with a minimum volume commitment of an average 9,167 Bbl/d in year one, 17,967 Bbl/d in year two, 18,800 Bbl/d for years three through five and 10,000 Bbl/d for years six through ten. The second agreement will commence in or around July 2019 and has a term of ten years for an average of 3,200 Bbl/d in year one, 8,000 Bbl/d in year two, 14,000 Bbl/d in year three, 16,000 Bbl/d in years four through eight, 12,000 Bbl/d in year nine and 10,000 Bbl/d in year ten. The remaining aggregate amount of estimated payments under these agreements is approximately \$875.8 million.

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

In February 2019, the Company entered into two long-term gas gathering agreements with third-party midstream providers. The first agreement will commence in or around November 2019 and has a term of twenty years with a minimum volume commitment of 251 Bcf to be delivered within the first seven years. The annual commitments over seven years are to be delivered on an average 48,000 Mcf/d in year one, 96,000 Mcf/d in year two, 132,000 Mcf/d in year three, 120,000 Mcf/d in year four, 108,000 Mcf/d in year five, 104,000 Mcf/d in year six and 80,000 Mcf/d in year seven. The aggregate amount of estimated payments under this agreement is approximately \$317.7 million. The second agreement 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. The Company 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.

Acquisition of Undeveloped Leasehold Acreage

The Company was party to an agreement during 2017 with an unrelated third party for which it has paid \$247.6 million through December 31, 2018 to complete its leasing program of approximately 38,800 net acres of undeveloped leasehold.

General

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

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

Legal Matters

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

Note 14—Related Party Transactions

Office Lease with Related Affiliate

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

Units Repurchased from Officer

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

Promissory Notes

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

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

Second Lien Notes

Several holders of Second Lien Notes were also members of Holdings. Of the \$430.0 million outstanding on the Second Lien Notes as of December 31, 2015, members held approximately \$311.7 million. These members were paid \$314.8 million upon repayment and termination of the Second Lien Notes in July 2016, including the prepayment penalty.

2021 Senior Notes

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

2024 Senior Notes

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

2026 Senior Notes

Several 5% stockholders of the Company were also holders of the 2026 Senior Notes. 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.

Series A Preferred Units

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

Series A Preferred Stock and Series B Preferred Units

As of the initial issuance of the \$185.3 million of Series B Preferred Units, members of Holdings held approximately \$135.3 million. Several holders of the Series A Preferred Stock are also 5% stockholders of the Company. As of the initial issuance in October 2016 of the \$185.3 million of Series A Preferred Stock, such stockholders held \$105.0 million.

Private Placement of Common Stock

Several 5% stockholders of the Company were also participants in the Private Placement. As of the initial issuance of \$457.0 million of common stock in December 2016, such stockholders purchased 2,503,370 shares for \$45.7 million.

Increased Ownership in an Unconsolidated Subsidiary

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

Related Party—Employee

Mr. Troy Owens, brother of Mr. Matthew R. Owens, the Company's President and a member of the Company's Board of Directors, is employed by the Company as an engineer. Consistent with market compensation for his services, Mr. Troy Owens received approximately \$0.2 million and \$0.2 million in aggregate cash compensation relating to the fiscal years ended December 31, 2018 and 2017, respectively. In addition, Mr. Troy Owens received certain long-term incentives during the same periods in the form of restricted stock units that vest over a period of three years.

Note 15—Segment Information

See *Note 2 — Basis of Presentation and Significant Accounting Policies, Segment Reporting* for a description of the Company's determination of its reportable segments. The Company's exploration and production segment revenues are derived from third parties. The Company's gathering and facilities segment is currently in the construction phase and no revenue generating activities have commenced.

Financial information of the Company's reportable segments was as follows for the year ended December 31, 2018. Capital expenditures for fixed assets later attributed to the gathering and facilities segment were \$4.9 million for the year ended December 31, 2017. There were no such capital expenditures for the year ended December 31, 2016. There were no revenues, operating expenses or other income (expense) attributed to the gathering and facilities segment for the years ended December 31, 2017 and 2016.

	For the Year Ended December 31, 2018			
	Exploration and Production	Gathering and Facilities	Elimination of Intersegment Transactions	Consolidated Total
Revenues:				
Revenues from external customers	\$ 1,060,743	\$ —	\$ —	\$ 1,060,743
Intersegment revenues	—	—	—	—
Total Revenues	<u>\$ 1,060,743</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 1,060,743</u>
Operating Expenses and Other Income (Expense):				
Depletion, depreciation, amortization and accretion	\$ 435,736	\$ 39	\$ —	\$ 435,775
Interest income	461	1,467	—	1,928
Interest expense	(123,330)	—	—	(123,330)
Earnings in unconsolidated subsidiaries	319	2,544	—	2,863
Total Operating Expenses and Other Income (Expense):	<u>\$ 313,186</u>	<u>\$ 4,050</u>	<u>\$ —</u>	<u>\$ 317,236</u>
Segment Assets	\$ 3,896,966	\$ 269,337	\$ (276)	\$ 4,166,027
Capital Expenditures	\$ 892,548	\$ 108,198	\$ —	\$ 1,000,745
Investment in Equity Method Investees	\$ —	\$ 15,487	\$ —	\$ 15,487
Segment EBITDAX	\$ 658,565	\$ 1,187	\$ —	\$ 659,752

The following table presents a reconciliation of Adjusted EBITDAX by segment to the GAAP financial measure of income (loss) before income taxes for the year ended December 31, 2018 (in thousands). The Company had a single reportable segment during the years ended December 31, 2017 and 2016, therefore no reconciliation is provided for these periods.

	For the Year Ended December 31, 2018
Reconciliation of Adjusted EBITDAX to Income Before Income Taxes	
Exploration and production segment EBITDAX	\$ 658,565
Gathering and facilities segment EBITDAX	1,187
Subtotal of Reportable Segments	\$ 659,752
Less:	
Depletion, depreciation, amortization and accretion	\$ (435,775)
Impairment of long lived assets and goodwill	(70,928)
Exploration expenses	(31,611)
Gain on sale of property and equipment	53,222
Gain on sale of assets of unconsolidated subsidiary	83,612
Loss on commodity derivatives	(8,554)
Settlements on commodity derivative instruments	123,518
Premiums paid for derivatives that settled during the period	7,148
Stock-based compensation expense	(68,349)
Amortization of debt issuance costs	(13,249)
Interest expense	(74,481)
Make-whole premium on 2021 Senior Notes	(35,600)
Income Before Income Taxes	\$ 188,705

Note 16—Supplemental Oil and Gas Reserve Information (Unaudited)

Results of Operations for Oil, Natural Gas and NGL Producing Properties

The following are the results of operations (in thousands) of the Company's oil and gas producing activities, before corporate overhead and interest expenses. The Company assumed a statutory rate of 24.7% for the year ended December 31, 2018 and 2017. The Company assumed a statutory tax rate of 38.0% for the year ended December 31, 2016, although the Company was not subject to federal and state income taxes prior to the Corporate Reorganization.

	For the Year Ended December 31,		
	2018	2017	2016
Revenues	\$ 1,060,743	\$ 604,296	\$ 278,089
Operating Expenses:			
Production expenses	209,169	162,673	82,773
Exploration expenses	31,611	36,256	36,422
Depletion and accretion	431,946	311,916	203,073
Impairment of proved properties	16,166	—	22,438
Results of operations before income tax (expense) benefit	371,851	93,451	(66,617)
Income tax (expense) benefit	(91,847)	(23,082)	25,314
Results of Operations	<u>\$ 280,004</u>	<u>\$ 70,369</u>	<u>\$ (41,303)</u>

Oil, Natural Gas and NGL Reserve Quantities (Unaudited)

The reserves at December 31, 2018, 2017 and 2016 presented below were prepared by the independent engineering firm Ryder Scott Company, L.P. All reserves are located within the DJ Basin. Proved oil, natural gas and NGL reserves are the estimated quantities of oil, natural gas and NGL which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions (i.e., prices and costs) existing at the time the estimate is made. Proved developed oil, natural gas and NGL reserves are proved reserves that can be expected to be recovered through existing wells and equipment in place and under operating methods being utilized at the time the estimates were made. The principal methodologies employed are decline curve analysis and analogy. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

The following table sets forth information for the years ended December 31, 2018, 2017 and 2016 with respect to changes in the Company's proved (i.e. proved developed and undeveloped) reserves:

	Crude Oil Mbbbls	Natural Gas MMcf	NGL Mbbbls	MBoe Total
Balance as of December 31, 2015	71,500.2	292,583.9	38,382.9	158,647.1
Revisions of previous estimates	(15,576.8)	35,803.1	1,988.8	(7,620.8)
Purchase of reserves	18,473.6	78,761.6	9,680.7	41,281.2
Extensions, discoveries, and other additions	21,885.4	120,798.3	14,679.9	56,698.5
Sale of reserves	—	—	—	—
Production	(5,287.4)	(20,211.5)	(2,284.0)	(10,940.0)
Balance as of December 31, 2016	90,995.0	507,735.4	62,448.3	238,066.0
Revisions of previous estimates	(625.9)	9,349.8	1,961.6	2,894.0
Purchase of reserves	10,761.2	11,183.6	1,563.3	14,188.3
Extensions, discoveries, and other additions	19,738.4	130,295.4	15,033.6	56,487.9
Sale of reserves	—	—	—	—
Production	(9,593.7)	(32,395.2)	(3,900.8)	(18,893.7)
Balance as of December 31, 2017	111,275.0	626,169.0	77,106.0	292,742.5
Revisions of previous estimates	6,264.3	(49,239.2)	(1,382.9)	(3,325.1)
Purchase of reserves	6,296.3	24,667.8	3,264.4	13,672.0
Extensions, discoveries, and other additions	32,475.3	164,424.0	22,853.4	82,732.7
Sale of reserves	(5,786.1)	(15,906.5)	(1,730.0)	(10,167.2)
Production	(14,679.3)	(46,846.6)	(5,260.1)	(27,747.2)
Balance as of December 31, 2018	135,845.5	703,268.5	94,850.8	347,907.7
Proved Developed Reserves, included above				
Balance as of December 31, 2016	17,158.0	107,918.0	13,354.0	48,498.4
Balance as of December 31, 2017	37,078.0	222,236.0	27,932.0	102,049.2
Balance as of December 31, 2018	47,075.0	316,499.0	39,689.0	139,514.0
Proved Undeveloped Reserves, included above				
Balance as of December 31, 2016	73,837.0	399,817.4	49,094.3	189,567.5
Balance as of December 31, 2017	74,197.0	403,933.0	49,174.0	190,693.2
Balance as of December 31, 2018	88,771.0	386,769.0	55,162.0	208,395.0

- The values for the 2018 oil, natural gas and NGL reserves are based on the 12-month arithmetic average of the first day of the month prices for the period from January through December 31, 2018. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were \$65.56 per barrel (West Texas Intermediate price) for crude oil and NGL and \$3.10 per MMBtu (Henry Hub price) for natural gas. All prices are then further adjusted for transportation, quality and

basis differentials. The average resulting price used as of December 31, 2018 was \$57.65 per barrel for oil, \$1.47 per Mcf for natural gas and \$20.45 per barrel for NGL.

- The values for the 2017 oil, natural gas and NGL reserves are based on the 12-month arithmetic average of the first day of the month prices for the period from January through December 31, 2017. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were \$51.34 per barrel (West Texas Intermediate price) for crude oil and NGL and \$2.98 per MMBtu (Henry Hub price) for natural gas. All prices are then further adjusted for transportation, quality and basis differentials. The average resulting price used as of December 31, 2017 was \$42.89 per barrel for oil, \$1.73 per Mcf for natural gas and \$20.28 per barrel for NGL.
- The values for the 2016 oil, natural gas and NGL reserves are based on the 12-month arithmetic average of the first day of the month prices for the period from January through December 31, 2016. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were \$42.75 per barrel (West Texas Intermediate price) for crude oil and NGL and \$2.49 per MMBtu (Henry Hub price) for natural gas. All prices are then further adjusted for transportation, quality and basis differentials. The average resulting price used as of December 31, 2016 was \$34.91 per barrel for oil, \$1.39 per Mcf for natural gas and \$11.63 per barrel for NGL.

For the year ended December 31, 2018, the Company had downward revisions of previous estimates of 3,325.1 MBoe. As a result of ongoing drilling and completion activities during 2018, the Company reported extensions, discoveries, and other additions of 82,732.7 MBoe. Additionally, during 2018 the Company sold reserves of 10,167.2 MBoe and purchased reserves of 13,672.0 MBoe.

For the year ended December 31, 2017, the Company had upward revisions of previous estimates of 2,894.0 MBoe. As a result of ongoing drilling and completion activities during 2017, the Company reported extensions, discoveries, and other additions of 56,487.9 MBoe. Additionally, during 2017 the Company purchased reserves of 14,188.3 MBoe.

For the year ended December 31, 2016, the Company had downward revisions of previous estimates of 7,620.8 MBoe. As a result of ongoing drilling and completion activities during 2016, the Company reported extensions, discoveries, and other additions of 56,698.5 MBoe. Additionally, during 2016 the Company purchased reserves of 41,281.2 MBoe.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil, Natural Gas and NGL Reserves

The Company follows the guidelines prescribed in ASC 932, *Extractive Activities-Oil and Gas* for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The following summarizes the policies used in the preparation of the accompanying oil, natural gas and NGL reserve disclosures, standardized measures of discounted future net cash flows from proved oil, natural gas and NGL reserves and the reconciliations of standardized measures from year to year.

The information is based on estimates of proved reserves attributable to the Company's interest in oil and gas properties as of December 31 of the years presented. These estimates were prepared by Ryder Scott Company L.P., independent petroleum engineers.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows: (1) Estimates are made of quantities of proved reserves and future periods during which they are expected to be produced based on year-end economic conditions. (2) The estimated future cash flows are compiled by applying the trailing twelve-month average of the first of the month prices applied to the Company's proved reserve year-end quantities. (3) The future cash flows are reduced by estimated production costs, costs to develop and produce the proved reserves and abandonment costs, all based on year-end economic conditions, plus Company overhead incurred. (4) Future net cash flows are discounted to present value by applying a discount rate of 10%.

The assumptions used to compute the standardized measure are those prescribed by the FASB and the SEC. These assumptions do not necessarily reflect the Company's expectations of actual revenues to be derived from those reserves, nor their present value. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations, since these reserve quantity estimates are the basis for the valuation process. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of the Company's oil and natural gas reserves. An estimate of fair value would also take into account, among other things, the

recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

The following summary sets forth the Company's future net cash flows relating to proved oil, natural gas and NGL reserves based on the standardized measure prescribed in ASC 932, *Extractive Activities-Oil and Gas* (in thousands):

	For the Year Ended December 31,		
	2018	2017	2016
Future crude oil, natural gas and NGL sales	\$ 10,805,063	\$ 7,422,335	\$ 4,610,848
Future production costs	(3,215,840)	(2,227,370)	(1,429,202)
Future development costs	(1,912,641)	(1,662,859)	(1,579,628)
Future income tax expense	(694,398)	(212,923)	(42,859)
Future net cash flows	\$ 4,982,184	\$ 3,319,183	\$ 1,559,159
10% annual discount	(2,082,201)	(1,440,177)	(836,163)
Standardized measure of discounted future net cash flows ⁽¹⁾	\$ 2,899,983	\$ 1,879,006	\$ 722,996

- (1) For the years ended December 31, 2018, 2017 and 2016, future income tax expenses in the Company's calculation of the standardized measure of discounted future net cash flows are based on year-end statutory tax rates giving effect to the remaining tax basis in the oil and gas properties, other deductions, credit and allowances relating to the Company's proved reserves. For purposes of the standardized measure calculation, it was assumed that all of the Company's operations are attributable to the Company's oil and gas assets.

The following are the principal sources of change in the standardized measure (in thousands):

	For the Year Ended December 31,		
	2018	2017	2016
Balance at beginning of period	\$ 1,879,006	\$ 722,996	\$ 835,883
Sales of crude oil, natural gas and NGL, net	(851,574)	(441,623)	(195,316)
Net change in prices and production costs	902,762	586,271	(325,236)
Net change in future development costs	(174,112)	3,959	(49,213)
Extensions and discoveries	629,304	330,160	96,982
Acquisitions of reserves	88,124	59,745	156,675
Sale of reserves	(55,042)	—	—
Revisions of previous quantity estimates	132,373	188,421	19,161
Previously estimated development costs incurred	306,546	331,550	123,085
Net changes in income taxes	(253,044)	(79,181)	(17,611)
Accretion of discount	197,580	74,061	83,588
Changes in production timing and other	98,060	102,647	(5,002)
Balance at end of period	\$ 2,899,983	\$ 1,879,006	\$ 722,996

Note 17—Unaudited Quarterly Financial Data

The following is a summary of the unaudited quarterly financial data for each of the quarters from first quarter 2017 through fourth quarter 2018 (in thousands, except per share data). Historical results are not necessarily indicative of the results to be expected in future periods. You should read this data together with the Company's consolidated financial statements and the related notes included elsewhere in this Annual Report:

	Three Months Ended			
	March 31,	June 30,	September 30,	December 31,
	2018	2018	2018	2018
Oil, Natural Gas and NGL Sales	\$ 230,215	\$ 260,196	\$ 282,160	\$ 288,172
Operating Income ⁽¹⁾	\$ 85,443	\$ 98,300	\$ 121,171	\$ 110,885
Net Income (Loss)	\$ (51,995)	\$ 8,848	\$ 65,150	\$ 99,852
Basic Income (Loss) Per Common Share	\$ (0.32)	\$ 0.03	\$ 0.33	\$ 0.52
Diluted Income (Loss) Per Common Share	\$ (0.32)	\$ 0.03	\$ 0.33	\$ 0.51

	Three Months Ended			
	March 31,	June 30,	September 30,	December 31,
	2017	2017	2017	2017
Oil, Natural Gas and NGL Sales	\$ 89,639	\$ 119,766	\$ 180,861	\$ 214,030
Operating Income (Loss) ⁽¹⁾	\$ 10,210	\$ 16,480	\$ 41,084	\$ 58,850
Net Income (Loss)	\$ 8,716	\$ 7,240	\$ (29,796)	\$ (30,568)
Basic and Diluted Income (Loss) Per Common Share	\$ 0.03	\$ 0.02	\$ (0.20)	\$ (0.20)

(1) Oil, Natural gas and NGL sales revenue less lease operating expenses, transportation and gathering expenses, production taxes and depreciation, depletion, amortization and accretion.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

In accordance with the Securities Exchange Act of 1934, as amended (the "Exchange Act"), Rules 13a-15(b) and 15d-15(b), we have evaluated, under the supervision and with the participation of our 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 December 31, 2018. 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 our 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 have concluded that our disclosure controls and procedures were effective as of December 31, 2018 at the reasonable assurance level.

Management's Annual Report on Internal Control over Financial Reporting

Our management, including our principal executive officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our consolidated financial statements for external purposes in accordance with generally accepted accounting principles. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Our management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2018, using the criteria established in *Internal Control-Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that our internal control over financial reporting was effective as of December 31, 2018.

PricewaterhouseCoopers LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this annual report on Form 10-K, has also audited the effectiveness of our internal control over financial reporting at December 31, 2018. Their "Report of Independent Registered Public Accounting Firm," which expresses an unqualified opinion on the effectiveness of our internal control over financial reporting at December 31, 2018, is included in Item 8.

Changes in Internal Control over Financial Reporting

There were no changes in our system of internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth quarter of 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

The information responsive to Items 401, 405, 406 and 407 of Regulation S-K to be included in our definitive Proxy Statement for our 2019 Annual Meeting of Shareholders, to be filed within 120 days of December 31, 2018, pursuant to Regulation 14A under the Securities Exchange Act of 1934, as amended (the “2019 Proxy Statement”), is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information responsive to Items 402 and 407 of Regulation S-K to be included in our 2019 Proxy Statement is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information responsive to Items 201(d) and 403 of Regulation S-K to be included in our 2019 Proxy Statement is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information responsive to Items 404 and 407 of Regulation S-K to be included in our 2019 Proxy Statement is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information responsive to Item 9(e) of Schedule 14A to be included in our 2019 Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents Filed With This Report

1. FINANCIAL STATEMENTS

The following consolidated financial statements of the Company are filed as a part of this report:

	PAGE
Report of Independent Registered Public Accounting Firm	90
Consolidated Balance Sheets as of December 31, 2018 and 2017	92
Consolidated Statements of Operations for the Years Ended December 31, 2018, 2017 and 2016	93
Consolidated Statements of Changes in Members' and Stockholders' Equity and Noncontrolling Interest	94
Consolidated Statements of Cash Flows for the Years Ended December 31, 2018, 2017 and 2016	96
Notes to Consolidated Financial Statements	98

2. FINANCIAL STATEMENT SCHEDULES

All financial statement schedules have been omitted because they are not applicable or the required information is presented in the consolidated financial statements and related notes.

3. EXHIBITS

The exhibits to this report required to be filed pursuant to Item 15(b) are listed below in the "Index to Exhibits" attached hereto and are incorporated herein by reference.

INDEX TO EXHIBITS

Exhibit Number	Description
**2.1	Agreement and Plan of Merger, dated October 17, 2016, by and between Extraction Oil & Gas, Inc. and Extraction Oil & Gas Holdings, LLC. (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
**3.1	Certificate of Incorporation of Extraction Oil & Gas, Inc., dated October 11, 2016 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
**3.2	Certificate of Designations of Series A Preferred Stock of Extraction Oil & Gas, Inc., filed with the Secretary of State of the State of Delaware on October 17, 2016 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
**3.3	Bylaws of Extraction Oil & Gas, Inc., dated October 11, 2016 (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
**4.1	Amended and Restated Registration Rights Agreement, dated October 17, 2016, by and among Extraction Oil & Gas, Inc. and the other persons named therein (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
**4.2	Registration Rights Agreement, dated October 3, 2016, by and among Extraction Oil & Gas, LLC, Extraction Oil & Gas Holdings, LLC and the other persons named therein (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
**4.3	Registration Rights Agreement, dated December 15, 2016, by and among Extraction Oil & Gas, Inc. and the purchasers named therein (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on December 16, 2016).
**4.4	Indenture, dated August 1, 2017, by and between Extraction Oil & Gas, Inc. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to exhibit 4.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on August 3, 2017).
**4.5	Indenture, dated as of January 25, 2018, by and among Extraction Oil & Gas, Inc., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to exhibit 4.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on January 25, 2018).
†**10.1	Extraction Oil & Gas, Inc. 2016 Long Term Incentive Plan (incorporated by reference to Exhibit 4.4 to the Company's Registration Statement on Form S-8 (File No. 333-214089) filed with the Commission on October 13, 2016).
†**10.2	Form of Restricted Stock Unit Award Agreement (for Employees) (incorporated by reference to Exhibit 4.5 to the Company's Registration Statement on Form S-8 (File No. 333-214089) filed with the Commission on October 13, 2016).
†**10.3	Form of Restricted Stock Unit Award Agreement (for Directors) (incorporated by reference to Exhibit 4.6 to the Company's Registration Statement on Form S-8 (File No. 333-214089) filed with the Commission on October 13, 2016).

- †**10.4 Form of Stock Option Award Agreement (incorporated by reference to Exhibit 4.7 to the Company's Registration Statement on Form S-8 (File No. 333-214089) filed with the Commission on October 13, 2016).
- †**10.5 Employment Agreement dated as of October 11, 2016 among the Company, XOG Services, LLC, and Mark A. Erickson (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
- †**10.6 Employment Agreement dated as of October 11, 2016 among the Company, XOG Services, LLC, and Matthew R. Owens (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
- †**10.7 Employment Agreement dated as of October 11, 2016 among the Company, XOG Services, LLC, and Russell T. Kelley, Jr. (incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
- †**10.8 Form of Indemnification Agreement (incorporated by reference to Exhibit 10.8 to the Company's Annual Report on Form 10-K (File No. 001-37907) filed with the Commission on February 27, 2018).
- †**10.9 Employment Agreement effective as of November 1, 2016 among the Company and Tom L. Brock (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 31, 2016).
- †**10.10 Amended and Restated Employment Agreement effective as of November 1, 2016 among the Company and Tom L. Brock (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 November 22, 2016).
- †**10.11 Employment Agreement effective as of November 7, 2016 among the Company and Eric J. Christ (incorporated by reference to Exhibit 10.11 to the Company's Annual Report on Form 10-K (File No. 001-37907) filed with the Commission on February 27, 2018).
- †**10.12 Amendment to Employment Agreement effective as of February 17, 2017 among the Company and Eric J. Christ (incorporated by reference to Exhibit 10.12 to the Company's Annual Report on Form 10-K (File No. 001-37907) filed with the Commission on February 27, 2018).
- **10.13 Common Stock Subscription Agreement, dated as of December 12, 2016, by and among Extraction Oil & Gas, Inc. and the purchasers named therein (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 December 12, 2016).
- **10.14 Amended and Restated Credit Agreement, dated as of August 16, 2017, by and between Extraction Oil & Gas, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent and issuing lender, and the lenders party thereto (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 21, 2017).
- **10.15 Increase Agreement, Joinder and Amendment No. 1 to Amended and Restated Credit Agreement, dated as of October 11, 2017, by and between Extraction Oil & Gas, Inc., as borrower, certain subsidiaries of the Company, as guarantors, Wells Fargo Bank, National Association, as administrative agent and issuing lender and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 13, 2017).
- **10.16 Master Assignment, Increase Agreement and Amendment No.2 to Amended and Restated Credit Agreement, dated as of January 5, 2018, by and between Extraction Oil & Gas, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent and issuing lender, and the lenders party thereto (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 January 9, 2018).

- **10.17 Consent Agreement and Amendment No. 3 to Amended and Restated Credit Agreement, dated as of February 27, 2018, by and between Extraction Oil & Gas, Inc., as borrower, certain subsidiaries of the Company, as guarantors, Wells Fargo Bank, National Association, as administrative agent and issuing lender and the lenders party thereto (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 March 2, 2018).
- **10.18 Amendment No. 4 to Amended and Restated Credit Agreement, dated as of May 23, 2018, by and between Extraction Oil & Gas, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent and issuing lender, and the lenders party thereto (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 May 29, 2018).
- **10.19 Consent and Amendment No. 5 to Amended and Restated Credit Agreement, dated as of October 2, 2018, by and among Extraction Oil & Gas, Inc., as borrower, certain of its subsidiaries, as guarantors, the lenders party thereto, and Wells Fargo Bank, National Association, as administrative agent and issuing lender (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 9, 2018).
- **10.20 Borrowing Base Increase Agreement, dated as of December 20, 2018, among Extraction Oil & Gas, Inc., as borrower, certain subsidiaries of Extraction Oil & Gas, Inc., as guarantors, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (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 December 26, 2018).
- **10.21 Consent and Amendment No. 6 to Amended and Restated Credit Agreement, dated as of January 8, 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 January 14, 2019).
- *21.1 Subsidiaries of the Registrant
- *23.1 Consent of PricewaterhouseCoopers LLP
- *23.2 Consent of Ryder Scott Company, L.P.
- *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.
- *99.1 Report of Ryder Scott Company, L.P.
- *101 Interactive Data Files

† Management contract or compensatory plan or agreement.

* Filed herewith.

** Previously filed.

ITEM 16. FORM 10-K SUMMARY

None.

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: February 21, 2019.

Extraction Oil & Gas, Inc.

By: /s/ MARK A. ERICKSON

Mark A. Erickson

Chairman and Chief Executive Officer
(Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

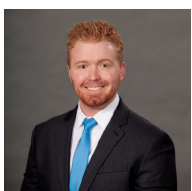
<u>/s/ RUSSELL T. KELLEY, JR.</u> Russell T. Kelley, Jr.	Chief Financial Officer (Principal Financial Officer)	February 21, 2019
<u>/s/ TOM L. BROCK</u> Tom L. Brock	Vice President, Chief Accounting Officer (Principal Accounting Officer)	February 21, 2019
<u>/s/ MATTHEW R. OWENS</u> Matthew R. Owens	President and Director	February 21, 2019
<u>/s/ JOHN S. GAENSBAUER</u> John S. Gaensbauer	Director	February 21, 2019
<u>/s/ PETER A. LEIDEL</u> Peter A. Leidel	Director	February 21, 2019
<u>/s/ MARVIN M. CHRONISTER</u> Marvin M. Chronister	Director	February 21, 2019
<u>/s/ PATRICK D. O'BRIEN</u> Patrick D. O'Brien	Director	February 21, 2019
<u>/s/ WAYNE W. MURDY</u> Wayne W. Murdy	Director	February 21, 2019
<u>/s/ DONALD L. EVANS</u> Donald L. Evans	Director	February 21, 2019

CORPORATE INFORMATION

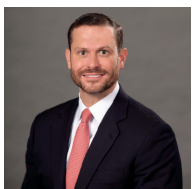
Management Team



Mark Erickson
*Chairman of the Board
and Chief Executive
Officer*



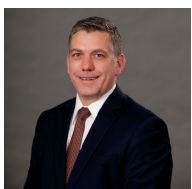
Matt Owens
President



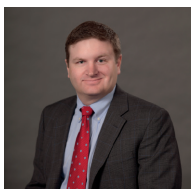
Russell Kelley
Chief Financial Officer



Eric Jacobsen
*Senior Vice President,
Operations*



Tom Brock
*Chief Accounting
Officer*



Eric Christ
*General Counsel and
Corporate Secretary*

Board of Directors

Mark Erickson
Chairman and CEO

Matt Owens
President

Wayne Murdy
Lead Director

Peter Leidel
Director

Marvin Chronister
Director

John Gaensbauer
Director

Pat O'Brien
Director

Donald Evans
Director

Additional Resources

Common Stock Information
The Common Stock is traded on the NASDAQ MKT under the symbol XOG.

Transfer Agent
American Stock Transfer & Trust Company
800-937-5449
help@astfinancial.com

Auditor
PricewaterhouseCoopers LLP

Reserve Engineers
Ryder Scott, Denver, CO

Form 10-K
Additional copies of the Company's Form 10-K as filed with the Securities and Exchange Commission, are available at our website, www.extractionog.com, under Investors.



Extraction Oil & Gas Inc. • 370 17th Street, Suite 5300 • Denver, CO 80202

www.extractionog.com