ROAN RESOURCES, INC.
Form 10-K
April 01, 2019

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

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF SECURITIES EXCHANGE ACT OF 1934
Commission File Number: 001-32720

Roan Resources, Inc.
(Exact Name of Registrant as Specified in its Charter)

Delaware (State or Other Jurisdiction of Incorporation)	83-1984112 (IRS Employer Identification No.)
14701 Hertz Quail Springs Pkwy Oklahoma City, OK (Address of Principal Executive Offices)	73134 (Zip Code)

(405) 896-8050
(Registrant's Telephone Number, including Area Code)
Linn Energy, Inc.
600 Travis Street
Houston, Texas 77002
(Former Name or Former Address, If Changed Since Last Report)
Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $0.001 par value	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No x
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 x
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 x 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 x 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. Yes x No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 12 b-2 of the Exchange Act.

Large Accelerated Filer ¨ Accelerated Filer ¨

Non-Accelerated Filer x 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 x

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes x No ¨

As of June 30, 2018, the last business day of Roan Resources, Inc.'s most recently completed second fiscal quarter, Roan Resources, Inc.'s Class A common stock was not listed on a domestic exchange or over-the-counter market. Roan Resources, Inc.'s Class A common stock began trading on the New York Stock Exchange on November 9, 2018. As of March 27, 2019, there were 152,539,532 shares of Class A common stock, par value $0.001 per share, outstanding.

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2019 Annual Meeting of Stockholders, which will be filed with the United States Securities and Exchange Commission within 120 days of December 31, 2018, are incorporated by reference into Part III of this Form 10-K for the year ended December 31, 2018.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of certain terms used in this document, which are commonly used in the oil and natural gas industry:

3-D seismic. Geophysical data that depicts the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

Analogous reservoir. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an analogous reservoir refers to a reservoir that shares the following characteristics with the reservoir of interest: (i) same geological formation (but not necessarily in pressure communication with the reservoir of interest); (ii) same environment of deposition; (iii) similar geological structure; and (iv) same drive mechanism. For a complete definition of analogous reservoir, refer to the Securities and Exchange Commission’s (“SEC”) Regulation S-X, Rule 4-10(a)(2).

Basin. A large natural depression on the earth’s surface in which sediments, generally brought by water, accumulate.

Bbl. One stock tank barrel of 42 U.S. gallons liquid volume used herein in reference to crude oil, condensate or NGLs.

Boe. One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

Btu. British thermal unit. The quantity of heat required to raise the temperature of a one pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Completion. Preparation of a well bore and installation of permanent equipment for production of oil, natural gas or NGLs or, in the case of a dry well, reporting to the appropriate authority that the well has been abandoned.

Condensate. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

Delineation. The process of placing a number of wells in various parts of a reservoir to determine its boundaries and production characteristics.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas. For a complete definition of development costs, refer to the SEC’s Regulation S-X, Rule 4-10(a)(7).

Development project. The means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a

producing field or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.
Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.
Differential. An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.
Dry well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.
Economically producible. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. For a complete definition of economically producible, refer to the SEC's Regulation S-X, Rule 4-10(a)(10).
Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.
Field. 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. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations. For a complete definition of field, refer to the SEC's Regulation S-X, Rule 4-10(a)(15).
Formation. A layer of rock which has distinct characteristics that differs from nearby rock.
Fracture stimulation. A process whereby fluids mixed with proppants are injected into a wellbore under pressure in order to fracture, or crack open, reservoir rock, thereby allowing oil and/or natural gas trapped in the reservoir rock to travel through the fractures and into the well for production.
Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.
Held by production or HBP. Acreage covered by a mineral lease that perpetuates a company's right to operate a property as long as the property produces a minimum paying quantity of oil or natural gas.
Horizontal drilling. A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.
Liquids. Describes oil, condensate and natural gas liquids.
MBbls. One thousand barrels of crude oil, condensate or NGLs.
MBoe. One thousand Boe.
MBoe/d. One thousand Boe per day.
Mcf. One thousand cubic feet of natural gas.
MMBtu. One million British thermal units.
MMcf. One million cubic feet of natural gas.

Net acres. The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% working interest in 100 acres owns 50 net acres.
Net production. Production that is owned by us less royalties and production due to others.
Net revenue interest. A working interest owner's gross working interest in production less the royalty, overriding royalty, production payment and net profits interests.
NGLs or Natural gas liquids. Hydrocarbons found in natural gas which may be extracted as liquefied petroleum gas and natural gasoline.
NYMEX. The New York Mercantile Exchange.
Operator. The individual or company responsible for the development and/or production of an oil or natural gas well or lease.
Play. A geographic area with hydrocarbon potential.
Production costs. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. For a complete definition of production costs, refer to the SEC's Regulation S-X, Rule 4-10(a)(20).
Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.
Proration unit. A unit that can be effectively and efficiently drained by one well, as allocated by a governmental agency having regulatory jurisdiction.
Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.
Proved developed non-producing or PDNP. Hydrocarbons in a potentially producing horizon penetrated by a wellbore, the production of which has been postponed pending installation of surface equipment or gathering facilities, or pending the production of hydrocarbons from another formation penetrated by the wellbore. The hydrocarbons are classified as proved but non-producing reserves.
Proved developed reserves. Reserves that can be expected to be recovered through (i) existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.
Proved properties. Properties with proved reserves.
Proved reserves. Those quantities of oil, natural gas and NGLs, 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. For a complete definition of proved oil and natural gas reserves, refer to the SEC's Regulation S-X, Rule 4-10(a)(22).

Proved undeveloped reserves or PUDs. 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 the specific circumstances justify a longer time. Under no circumstances shall estimates for 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. The present value of estimated future cash inflows from proved oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows.

Realized price. The cash market price less all expected quality, transportation and demand adjustments.

Reasonable certainty. A high degree of confidence that quantities will be recovered. For a complete definition of reasonable certainty, refer to the SEC's Regulation S-X, Rule 4-10(a)(24).

Recompletion. The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

Reliable technology. 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.

Reserves. Estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

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

Resources. Quantities of oil and natural gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

Royalty. An interest in an oil and natural gas lease that gives the owner the right to receive a portion of the production from the leased acreage (or of the proceeds from the sale thereof), but does not require the owner to pay any portion of the production or development costs on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.
Section. 640 acres.
Spacing. The distance between wells producing from the same reservoir.
Spud. Commenced drilling operations on an identified location.
Standardized measure. Discounted future net cash flows estimated by applying year end prices to the estimated future production of year end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.
Undeveloped acreage. Lease 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.
Unit or spacing unit. 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.
Unproved properties. Properties with no proved reserves.
Wellbore. The hole drilled by the bit that is equipped for oil, natural gas and NGL production on a completed well. Also called well or borehole.
Working interest. The right granted to the lessee of a property to develop and produce and own natural gas or other minerals. The working interest owners bear the exploration, development and operating costs on either a cash, penalty or carried basis.
Workover. Operations on a producing well to restore or increase production.
WTI. West Texas Intermediate.

GLOSSARY OF OTHER TERMS
The following are abbreviations and definitions of certain terms used in this document:
Roan Inc. or the Company. Refers to Roan Resources, Inc.
Roan LLC. Refers to Roan Resources LLC, our predecessor.
Citizen. Refers to Citizen Energy II, LLC, the predecessor of Roan LLC for financial reporting purposes and a party to the Reorganization.
Old Linn or Linn. Refers to Linn Energy, Inc. prior to the Riviera Separation and a party to the Contribution and Reorganization.
New Linn. Refers to New LINN Inc. (subsequently renamed Linn Energy, Inc.).
Contribution. Refers to the contribution agreement completed by Roan LLC, Old Linn and Citizen in August 2017 to contribute certain oil and natural gas assets to Roan LLC.
Roan Holdings. Refers to Roan Holdings, LLC.
Reorganization. Refers to the reorganization transactions contemplated by the master reorganization agreement, dated September 17, 2018, by and among Linn Energy, Inc., Roan Holdings, LLC, and Roan Resources LLC, pursuant to which New Linn's and Roan Holdings' respective 50% equity interest in Roan LLC were moved under Roan Inc.
Riviera. Refers to Riviera Resources, Inc.
Riviera Separation. Refers to the reorganization transactions pursuant to which Old Linn contributed certain of its assets to Riviera except for its 50% equity interest in Roan LLC, as further described in Reorganization.
Merge. Refers to the play located in Canadian, Grady and McClain counties in the Anadarko Basin of Oklahoma.
SCOOP. Refers to the South Central Oklahoma Oil Province play principally located in the Anadarko Basin area of Oklahoma.
STACK. Refers to the Sooner Trend, Anadarko (Basin), Canadian and Kingfisher play located in the Anadarko Basin area of Oklahoma.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (the "Annual Report" or "Form 10-K") includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements, other than statements of historical fact included in this Annual Report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "project" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on management's current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should carefully consider the risk factors and other cautionary statements described under Part I, Item 1A. "Risk Factors" of this Annual Report.
Forward-looking statements may include statements about:

- our business strategy;
- our reserves;
- our drilling plans, prospects, inventories, projects and programs;
- our ability to replace the reserves we produce through drilling and property acquisitions;
- our financial strategy, liquidity and capital required for our drilling program and timing related thereto;
- our realized oil, natural gas and NGL prices;
- the timing and amount of our future production of oil, natural gas and NGLs;
- our competition and government regulations;
- our ability to obtain permits and governmental approvals;
- our pending legal or environmental matters;
- our marketing of oil, natural gas and NGLs;
- our leasehold or business acquisitions;
- our costs of developing our properties;
- our hedging strategy and results;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results including initial production values and liquid yields in our type curve areas;
- the costs, terms and availability of gathering, processing, fractionation and other midstream services; and
- our plans, objectives, expectations and intentions that are not historical.

These forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incidental to the development, production, gathering and sale of oil, natural gas and NGLs. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures and the other risks described in Part I, Item 1A. "Risk Factors" of this Annual Report.

Reserve engineering is a process of estimating underground accumulations of oil, natural gas and NGLs 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 NGLs that are ultimately recovered.

PART I

ITEM 1 and 2. BUSINESS AND PROPERTIES

Organization

Our predecessor, Roan LLC, was initially formed by Citizen in May 2017. In June 2017, subsidiaries of Old Linn, together with Citizen and Roan LLC entered into the Contribution, pursuant to which, among other things, Old Linn and Citizen agreed to contribute certain oil and natural gas assets to Roan LLC, each in exchange for a 50% equity interest in Roan LLC. On August 31, 2017, Old Linn and Citizen consummated the transactions contemplated by such contribution agreement. Following these transactions, Citizen's equity interest in Roan LLC was held through its wholly-owned subsidiary, Roan Holdings.

In the third quarter of 2018, Old Linn and certain of its subsidiaries undertook an internal reorganization, pursuant to which Old Linn merged with and into a wholly-owned subsidiary of New Linn. Following such internal reorganization, New Linn completed the spin-off of substantially all of its assets, other than its 50% equity interest in Roan LLC.

On September 17, 2018, New Linn, Roan Holdings and Roan LLC entered into a master reorganization agreement, to effectuate the reorganization of New Linn's and Roan Holdings' respective 50% equity interests in Roan LLC under Roan Inc. On September 24, 2018, the Company consummated the Reorganization, which resulted in the existing stockholders of New Linn receiving 50% of the Class A common stock of the Company and Roan Holdings receiving 50% of the Class A common stock of the Company. In connection with the Reorganization, the Company became the owner, indirectly through its wholly-owned subsidiaries, of 100% of the equity in, and is the sole manager of, Roan LLC. The Company is responsible for all operational, management and administrative decisions relating to Roan LLC's business.

Roan Inc. was incorporated in September 2018 to serve as a holding company and, prior to our reorganization, had no previous operations, assets or liabilities. Unless otherwise indicated, the historical financial, reserve and operational information presented in this Annual Report (i) on and after September 24, 2018, is that of Roan Inc., and (ii) prior to September 24, 2018, is that of Roan LLC, our predecessor. The historical financial and operational information of Roan LLC presented in this Annual Report, (i) prior to August 31, 2017, the date of the completion of the Contribution (as defined herein), is that of Citizen, the predecessor of Roan LLC for financial reporting purposes and (ii) on and after August 31, 2017, is that of Roan LLC. Therefore, the historical financial and operating information of Citizen prior to August 31, 2017 does not include financial information relating to certain oil and natural gas assets contributed to Roan LLC by subsidiaries of Old Linn.

On November 9, 2018, the Company's Class A common stock began trading on the New York Stock Exchange under the symbol "ROAN."

Overview

We are an independent oil and natural gas company focused on the development of our assets throughout the eastern and southern Anadarko Basin. We focus our development on formations where we believe we can apply our technical and operational expertise in order to increase production and cash flow.

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Through December 31, 2018, we and our predecessors have drilled 214 gross (72 net) wells in the Merge, SCOOP, and STACK plays. Our acreage position is concentrated in areas that we believe demonstrate higher percentage production of oil and NGLs, and provides us development opportunities through multiple stacked prospective development horizons. We believe these development horizons have been substantially de risked through the development of more than 400 horizontal wells since early 2014, of which 152 were drilled by us or our predecessors, and over 4,450 vertical wells drilled in our development area, as well as associated subsurface data, including well cores and logs and 3-D seismic and the consistent geology surrounding our position. As of December 31, 2018, we operated 163 gross (131 net) horizontal producing wells and had an interest in an additional 317 gross (19 net) horizontal producing wells.

As of December 31, 2018, we held leasehold interests in approximately 383,000 gross (172,000 net) acres in the Anadarko Basin. At December 31, 2018, our total estimated proved reserves were approximately 305,959 MBoe. For the quarter ended December 31, 2018, our average net daily production was 54.1 MBoe/ d (approximately 27% oil, 42% natural gas and 31% NGLs).

Our Business Strategies

Our primary objective is to maximize shareholder value across business cycles by pursuing the following strategies:

- Generate attractive full-cycle returns through the efficient development of our extensive, low risk drilling inventory. We intend to efficiently achieve industry leading rates of return by leveraging the scale of our core leasehold positions, experience from the success of our drilling program to date, technical understanding of the reservoirs, our extensive catalogue of technical information and experience of our operational teams. We intend to allocate capital in a disciplined manner to projects that we believe will produce predictable and attractive full-cycle rates of return.

- Maximize value of our asset base through constant focus on improving operating, production and capital efficiencies. We utilize proprietary data analytics, combined with operational procedures and metrics, to evaluate well results and adjust drilling and production techniques in real time. We use this framework in an effort to maximize hydrocarbon recoveries per well by optimizing location selection, wellbore targeting, well completion designs and production techniques. Additionally, we seek to reduce capital and operating costs of drilling and completing horizontal wells by decreasing development cycle times, optimizing the use of surface facilities, capitalizing on our knowledge of the target formations and focusing on service cost management practices.

- Maintain a high degree of operational control to facilitate efficient development and capital budgeting. We seek to maintain operational control of our properties in order to better execute on our strategy of enhancing returns through operational improvements and cost efficiencies. As of December 31, 2018, we operated approximately 71% of our total acreage. We believe that maintaining a high degree of control of the development of our properties and of our production enables us to increase hydrocarbon recovery rates, lower capital and operating costs and improve drilling performance through optimization of our drilling, completion and production management techniques. Additionally, we believe operatorship allows us to control wellsite selection, spacing and lateral targeting and manage the pace of our development activities, which we believe can significantly enhance full-cycle returns.

- Maintain a disciplined, returns-driven strategy with a focus on maintaining financial flexibility. We intend to maintain a conservative financial profile that will afford us flexibility through the commodity price and capital market cycles inherent in the oil and natural gas industry. We intend to generate stable production and reserves growth by funding our development program primarily with cash flow from operations, borrowings under our credit facility and capital markets offerings.

- Selectively pursue opportunities to augment our asset base through the disciplined acquisition or leasing of oil and natural gas properties. As one of the most active operators in Oklahoma, we believe we are well positioned to selectively pursue accretive consolidation opportunities. We believe the strength of our operational program provides a competitive advantage in the pursuit of such opportunities. We will continue to identify and evaluate acquisition and leasing opportunities around and within our concentrated acreage position, as well as other areas in Oklahoma, that meet our strategic and financial objectives.

Our Competitive Strengths

We believe the following strengths will allow us to successfully execute on our business strategies:

- Large, contiguous acreage position in the core of the Merge play with significant operational control. We are the largest leaseholder in the Merge play, with approximately 115,000 net acres as of December 31, 2018. We believe that the scale and concentration of our acreage position allows for efficient field development through long laterals and shared facilities, with approximately 80% of our Merge sections capable of 1.5 mile or longer lateral development. Additionally, our acreage position is concentrated in areas that we believe demonstrate higher percentage production of oil and NGLs within the Merge play, and provides us development opportunities through multiple stacked prospective development horizons. As of December 31, 2018, we operated 81% of our net acreage in the Merge and we intend to maintain operational control over the majority of our drilling inventory, as we believe this enables us to increase our production and reserves and control our development costs, and ultimately increase shareholder value.

- Long-lived inventory of locations with predictable production profiles that provide high rate-of-return development opportunities. Through the drilling of 163 operated horizontal wells and participation in 317 non-operated horizontal wells across our acreage, we have substantially delineated our acreage and have acquired significant amounts of subsurface information. Based on this delineation and general industry Merge, SCOOP and STACK well production history, we believe that our acreage position will provide a large portfolio of drilling locations characterized by long-lived reserves, predictable production profiles and attractive return potential.

- Geographically advantaged assets with significant available midstream infrastructure and favorable regulatory climate. Our acreage position is in close proximity or has available access to end markets for oil, natural gas and NGLs, providing us with a regional price advantage relative to other U.S. onshore oil-weighted basins. For example, our realized oil price differential to NYMEX WTI average prices in the year ended December 31, 2018 was $1.67 per barrel compared to a WTI-Midland oil price differential to NYMEX WTI average prices in the year ended December 31, 2018 of $7.29 per barrel. Oklahoma has a long history of oil and natural gas production, and therefore there is existing midstream infrastructure in place across our acreage position to support our drilling program. In addition, we believe that oilfield services availability is greater in our focus area than in other major U.S. onshore basins and that such availability is a competitive advantage in assuring the ability to access necessary development services at attractive pricing.

- Experienced operations leadership with substantial technical expertise. We believe our operational management team provides us with a distinct competitive advantage. Our team has significant experience working together throughout the Mid-Continent and evaluating the Merge play in particular. Collectively, our Chief Executive Officer, Executive Vice President - Operations and Marketing, Executive Vice President - Geosciences and Business Development and members of our operations management team have over 90 years of experience in the oil and natural gas industry and have been involved in drilling over 1,000 horizontal wells across multiple plays in the lower 48 states. We believe their experience is instrumental in the execution of our pursuit of operational and capital efficiencies.

- Significant financial strength and flexibility. We believe we have a strong financial position, including a low debt profile and a large production base that generates significant cash flow, allowing us to strategically allocate capital in order to enhance shareholder value. We are well-positioned to adjust our development program based on market and industry conditions, as we have minimal commitments to deliver specified volumes, no rig contracts extending beyond 12 months and approximately 84% of our acreage is HBP as of December 31, 2018. We believe that our conservative capital structure, which we will seek to maintain through a disciplined approach to capital spending, and other potential financing sources will provide us with sufficient liquidity and flexibility to execute our development capital program.

Our Properties

We own leasehold interests in oil and natural gas properties located in the Anadarko Basin in Oklahoma. The Anadarko Basin, which spans from south-central Oklahoma to the northeast corner of the Texas panhandle, is one of the largest and most prolific onshore oil and natural gas basins in the United States, featuring multiple producing horizons and extensive well production history demonstrated over seven decades of development. We focus our development on formations where we believe we can apply our technical and operational expertise in order to increase production and cash flow to deliver compelling economic rates of return on a risk adjusted basis. Given the long productive history in these areas, there is substantial midstream and service infrastructure in place, including natural gas and NGL pipelines and natural gas processing plants.

As of December 31, 2018, we had assembled a total leasehold position of approximately 172,000 net acres, which is predominantly concentrated in the Merge and SCOOP plays. In addition to the subsurface benefits of our position, we believe our acreage position benefits from the following characteristics:

- High Degree of Operational Control. We expect that we will be able to control operations on approximately 71% of our acreage in the Merge, SCOOP and STACK plays. For these purposes, we have assumed that we will control any unit in which we have leased a minimum of 37.5% of the acreage in the unit. Operational control of our leasehold positions allows us to control the development and production methods, as well as the pace of development on our wells.

- Contiguous Acreage Position. A substantial portion of the sections in which we have operational control are offset to the north or south by adjacent controlled sections. Specifically, approximately 66% of our sections in the Merge, SCOOP and STACK plays can be developed on a multi-unit basis. As a result, we are able to develop long lateral horizontal wells for the majority of our drilling program, which we believe have exhibited superior economics as compared to shorter laterals as a result of development cost efficiencies.

- Largely Held-by-Production. Approximately 84% of our total acreage position was HBP as of December 31, 2018. We expect this high percentage of HBP acreage to enhance capital efficiencies in our development program, as we will pursue development locations with the favorable risk-adjusted rates of return in our location selection process, as opposed to selecting locations in order to hold acreage.

We refer to gross and net acreage where we are designated as operator or expect to be designated as operator based on the size of our working interest relative to other working interest owners as “our operated acreage” or acreage we “operated” in this Annual Report. As of December 31, 2018, we operated approximately 71% of our net acreage and had an average working interest of approximately 70% in all of our operated acreage. From January 1, 2018 through December 31, 2018, we drilled or participated in 214 gross horizontal wells that had first sales as of December 31, 2018.

As of December 31, 2018, approximately 84% of our total net acreage was held by production. This positions us to control the pace of our development efforts, strategically develop our acreage with a near-term focus on high-return projects, limit expenditures on lease renewals and limit the risk of losing high quality acreage through expiration of leases. Additionally, we closely monitor activity of other industry participants and adjust our future development plans based on information and what we believe to be best practices learned from our peers.

For the year ended December 31, 2018, our average net daily production was 43.7 MBoe/d (approximately 27% oil, 44% natural gas and 29% NGLs). During 2017, our average net daily production was 16.2 MBoe/d (approximately 25% oil, 49% natural gas and 26% NGLs). As of December 31, 2018, we had 1,263 gross (502 net) producing wells online, operated and non-operated.

Our Drilling Program and Completion Techniques

We intend to target accretive growth in production and cash flow by developing and expanding our significant portfolio of drilling locations. We believe that our recent well results demonstrate that many of our development projects are capable of producing attractive rates of return that are competitive with many of the top performing basins in the United States. We are focused on drilling wells with high rates of return, repeatable production profiles and increasing estimated ultimate recoveries while at the same time seeking to capitalize on drilling, completion and operating efficiencies. Our management team assumed operation of our properties in the first half of 2018 and has achieved meaningful operational advancements, including (i) improvement in lateral targeting, (ii) reductions in development cycle times, (iii) optimization testing of well completion methods, (iv) well flowback management, and (v) expanded subsurface data coverage, including 3-D seismic.

Oil and Natural Gas Data

Proved Reserves

Evaluation of Proved Reserves. Approximately 93% of our proved reserve estimates as of December 31, 2018 were prepared by DeGolyer and MacNaughton, our independent reserve engineers. Our personnel prepared reserve estimates with respect to the remaining approximate 7% of our proved reserves as of December 31, 2018.

DeGolyer and MacNaughton is a petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. Within DeGolyer and MacNaughton, the technical person primarily responsible for preparing our reserves estimates was Gregory K. Graves, P.E. Mr. Graves is a Registered Professional Engineer in the State of Texas (License No. 70734), is a member of both the Society of Petroleum Engineers ("SPE") and the Society of Petroleum Evaluation Engineers and has in excess of 35 years of experience in oil and natural gas reservoir studies and reserves evaluations. Mr. Graves graduated from the University of Texas at Austin in 1984 with a Bachelor of Science degree in Petroleum Engineering.

Mr. Graves meets the requirements with regard to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE.

DeGolyer and MacNaughton does not own an interest in any of our properties, nor is it employed by us on a contingent basis. A copy of DeGolyer and MacNaughton's proved reserve report as of December 31, 2018 is included as an exhibit to this 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. Our internal technical team members meet with our independent reserve engineers periodically to review properties and to discuss the assumptions and methods used in the proved reserve estimation process. Our Corporate Reserves Advisor, who is primarily responsible for overseeing the preparation of the reserves estimates by DeGolyer and MacNaughton, holds a Bachelor of Science in petroleum engineering technology, has over 25 years of industry experience and over 10 years of experience in corporate reserves preparation. Additionally, our Reservoir Engineering Manager, who assists our Corporate Reserves Advisor in the reserve preparation process, has 13 years of industry experience in reserve estimation and petroleum economics. Our Reservoir Engineering Manager holds a Bachelor of Science in engineering and geology as well as a Master of Business Administration degree. They are supported by a staff of 8 professionals with an average industry experience of 10 years, all of whom hold a Bachelor degree or higher.

The preparation of our proved reserve estimates was completed in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

- review and verification of historical production data, which data is based on actual production as reported by us;
- review of reserve estimates by our Reservoir Engineering Manager or under his direct supervision;
- review by our Executive Vice President—Operations and Marketing of all of our reported proved reserves, including the review of all significant reserve changes and all new PUDs additions;
- review by our management team of reported proved reserves and significant reserve changes;
- direct reporting responsibilities by our Reservoir Engineering Manager to our Executive Vice President—Operations and Marketing; and
- verification of property ownership by our land department.

Estimation of Proved Reserves. Under SEC rules, proved reserves are those quantities of oil and natural 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. 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 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 and natural gas 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 reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into four broad categories or methods: (i) production performance-based methods; (ii) material balance-based methods; (iii) volumetric-based methods; and (iv) 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 reasonably high degree of accuracy. Non-producing reserve estimates, for developed and undeveloped properties, were forecast using analogy methods. This method provides a reasonably high degree of accuracy for predicting PDNP and PUD reserves for our properties, due to the abundance of analog data.

To estimate economically recoverable proved reserves and related future net cash flows, we 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 have been field tested and have 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, available seismic data and historical well cost and operating expense data.

Summary of Reserves. The following table presents summary data with respect to our estimated net proved reserves as of December 31, 2018. The reserve estimates attributable to our properties as of December 31, 2018, were prepared in accordance with the rules and regulations of the SEC regarding reserve reporting.

Proved developed reserves	
Oil (MBbls) (1)	18,652
Natural gas (MMcf)	369,677
NGLs (MBbls)	39,927
Total (MBoe) (1)	120,192
Proved undeveloped reserves	
Oil (MBbls)	37,031
Natural gas (MMcf)	541,505
NGLs (MBbls)	58,485
Total (MBoe) (1)	185,767
Total proved reserves	
Oil (MBbls)	55,683
Natural gas (MMcf)	911,182
NGLs (MBbls)	98,412
Total (MBoe) (1)	305,959
Benchmark Oil and Natural Gas prices (2)	
Oil - WTI per Bbl	$65.66
Natural gas - Henry Hub per MMBtu	$3.16
Standardized measure (in thousands) (3)	$1,699,701
PV-10 of proved reserves (in thousands) (4)	$2,091,509

(1) Totals may not sum or recalculate due to rounding.

(2) Our estimated net proved reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance adjusted for quality, transportation fees, regional price differentials, and in the case of natural gas, energy content. For oil and NGLs volumes, the average WTI posted price of $65.66 per barrel as of December 31, 2018, was adjusted for gravity, quality, local conditions, gathering, transportation fees and distance from market. For natural gas volumes, the average Henry Hub spot price of $3.16 per MMBtu as of December 31, 2018 was similarly adjusted for gravity, quality, local conditions, gathering, transportation fees and distance from market. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $64.49 per barrel of oil, $20.35 per barrel of NGLs and $1.90 per Mcf of natural gas as of December 31, 2018.

(3) Please see “Risk Factors— The standardized measure of our estimated reserves contained in this Annual Report and in the footnotes to our financial statements is not an accurate estimate of the current fair value of our estimated reserves.”

(4) PV-10 is not a financial measure calculated or presented in accordance with GAAP and generally differs from standardized measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor standardized measure represents an estimate of the fair market value of our oil and natural gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities. The following table reconciles the GAAP standardized measure of discounted future net cash flows to PV-10 at December 31, 2018 (in thousands):

Standardized measure of discounted future net cash flows	$1,699,701
Present value of future income taxes discounted at 10%	391,808
PV-10 of proved reserves	$2,091,509

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 see “Risk Factors” appearing elsewhere in this Form 10-K.

Additional information regarding our proved reserves can be found in the notes to our consolidated financial statements included in Part II, Item 8 of this Form 10-K and in the reserve report of DeGolyer and MacNaughton as of December 31, 2018, which is included as an exhibit to this Form 10-K.

PUDs

As of December 31, 2018, our PUDs totaled 37,031 MBbls of oil, 541,505 MMcf of natural gas and 58,485 MBbls of NGLs, for a total of 185,767 MBoe. PUDs will be converted from undeveloped to developed as the applicable wells are drilled and begin production.

The following table summarizes our changes in PUDs during the year ended December 31, 2018 (in MBoe):

Balance, December 31, 2017	151,724
Extensions and discoveries	127,804
Revisions of previous estimates	(67,260)
Transfers to proved developed	(26,501)
Balance, December 31, 2018	185,767

Extensions and discoveries of 127,804 MBoe during the year ended December 31, 2018 resulted primarily from proved undeveloped locations added as a result of the continued development of our acreage and the drilling activity of other operators in the area. Downward revisions of previous estimates of 67,260 MBoe during the year ended December 31, 2018 were primarily due to adjustments to unit spacing, wellbore lateral length and other factors as we refined our current development plan. During the year ended December 31, 2018, we spent $119.8 million to convert 26,501 MBoe to proved developed producing reserves.

Our estimated future development costs relating to the development of PUDs at December 31, 2018 are projected to be approximately $1.2 billion over the next five years, which we expect to finance through cash flow from operations, borrowings under our credit facility and other sources of capital. All of our proved undeveloped reserves are expected to be developed within five years of initial booking. Please see “Risk Factors—The development of our estimated PUDs may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated PUDs may not be ultimately developed or produced.”

As of December 31, 2018, approximately 21,930 MBoe of our total proved reserves relating to 33 drilled but uncompleted wells (“DUCs”) were classified as PUDs, which is reflected in proved undeveloped reserves above. These DUCs are all scheduled to be completed within the next six months and have remaining completion costs of approximately $98.7 million.

Production and Price History

The following table sets forth information regarding net production of oil, natural gas and NGLs, and certain price and cost information for each of the periods indicated:

	Years Ended December 31,		
	2018	2017	2016
Production Data			
Oil (MBbls)	4,364	1,454	739
Natural gas (MMcf)	41,890	17,582	6,382
Natural gas liquids (MBbls)	4,592	1,524	546
Total volumes (MBoe)	15,938	5,908	2,349
Average daily total volumes (MBoe/d)	43.7	16.2	6.4
Average Prices - as reported (1)			
Oil (per Bbl)	$63.07	$52.87	$41.36
Natural gas (per Mcf)	$1.82	$2.80	$2.52
Natural gas liquids (per Bbl)	$19.27	$26.44	$15.21
Total (per Boe)	$27.59	$28.16	$23.40
Average Prices - including impact of derivative contract settlements (1)			
Oil (per Bbl)	$55.87	$53.57	$41.36
Natural gas (per Mcf)	$1.73	$2.89	$2.52
Natural gas liquids (per Bbl)	$19.60	$26.44	$15.21
Total (per Boe)	$25.50	$28.60	$23.40
Average Prices - excluding gathering, transportation and processing costs (2)			
Oil (per Bbl)	$63.11	$52.87	$41.36
Natural gas (per Mcf)	$2.29	$2.80	$2.52
Natural gas liquids (per Bbl)	$24.83	$26.44	$15.21
Total (per Boe)	$30.46	$28.16	$23.40
Average Costs per Boe			
Production expenses	$2.99	$2.86	$2.17
Gathering, transportation and processing (1)	$—	$3.15	$2.52
Production taxes	$1.10	$0.62	$0.46
General and administrative (3)	$3.82	$5.31	$2.38

(1) Average prices and costs for the year ended December 31, 2018 reflect the adoption of Accounting Standards Codification Topic 606 Revenue from Contracts with Customers (“ASC 606“) on January 1, 2018. The adoption of ASC 606 requires certain costs that were previously recorded as gathering, processing and transportation expenses to be accounted for as a deduction from revenue. We elected the modified retrospective method of transition. Accordingly, comparative information has not been adjusted and continues to be reported under the previous revenue standard.

(2) Excludes the effects of netting gathering, transportation and processing costs under ASC 606.

(3) General and administrative expenses for the years ended December 31, 2018 and 2017 include $0.69 per Boe and $0.06 per Boe of equity-based compensation expense, respectively.

Productive Wells

The following table sets forth information as of December 31, 2018 relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells, wells capable of production and wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, operated and non-operated, and net wells are the sum of our fractional working interests owned in gross wells.

	Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Operated	140	110	451	339	591	449
Non-operated	318	19	354	34	672	53
Total	458	129	805	373	1,263	502

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2018, relating to our leasehold acreage. Developed acreage consists of 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 defined as 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.

Developed Acreage		Undeveloped Acreage		Total Acreage	
Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
298,019	144,932	85,411	27,038	383,430	171,970

(1) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(2) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

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. As of December 31, 2018, approximately 84% of our total net acreage was held by production.

The following table sets forth the gross and net undeveloped acreage, as of December 31, 2018, that will expire over the next five years 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.

2019		2020		2021		2022		2023 and Thereafter	
Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
19,563	6,675	42,712	10,766	10,944	4,056	—	—	—	—

We intend to extend substantially all of the net acreage associated with our inventory of drilling locations through a combination of development drilling and leasehold extension and renewal payments. Of the 6,675 net acres expiring in 2019 and the 10,766 net acres expiring in 2020, we have the right to extend on 1,017 and 1,750 net acres, respectively.

Drilling Results

The following table sets forth the results of our drilling activity, as defined by wells having been placed on production, for the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return. Dry wells are those that prove to be incapable of producing hydrocarbons in sufficient quantities to justify completion.

	For the Years Ended December 31,					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive[1]	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total Exploratory	—	—	—	—	—	—
Development Wells						
Productive[1]	214	72	93	35	55	19
Dry	—	—	—	—	—	—
Total Development	214	72	93	35	55	19
Total Wells						
Productive[1]	214	72	93	35	55	19
Dry	—	—	—	—	—	—
Total	214	72	93	35	55	19

(1) Although a well may be classified as productive upon completion, future changes in oil and natural gas 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 33 gross (24 net) wells waiting on completion with associated remaining net completion costs of approximately $98.7 million.

Operations

General

As of December 31, 2018, we operated approximately 71% of our net acreage position. As operator, we design and manage the development of a well and supervise operation and maintenance activities on a day to day basis. We employ petroleum engineers, geologists and land professionals who work to improve

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production rates, increase reserves and lower the cost of operating our oil and natural gas properties.

Marketing and Customers

We market the majority of our production from properties we operate for both our account and the account of the other working interest owners in these properties. We sell our oil, natural gas and NGL production to purchasers at market prices, adjusted for quality, transportation fees, regional price differentials, and in the case of natural gas, energy content. While a majority of our natural gas and NGLs is sold under long term contracts with terms of greater than twelve months, a portion is sold under six month and month to month contracts. We sell all of our oil under contracts with terms of twelve months or less.

We normally sell our production to a relatively small number of customers, as is customary in our business. The following table identifies customers from whom we derived 10% or more of receipts from the sale of oil, natural gas and NGLs during the years ended December 31, 2018, 2017 and 2016:

	Years Ended December 31,		
	2018	2017	2016
Coffeyville Resources Refining & Marketing LLC	31%	*	*
Sunoco Inc.	18%	40%	55%
Blue Mountain Midstream LLC	15%	*	*
EnLink Oklahoma Gas Processing, LP	13%	39%	31%

* Revenue from customer was less than 10% in this period.

Blue Mountain Midstream LLC (“Blue Mountain”) is deemed a related party as it is a wholly-owned subsidiary of Riviera.

If a major customer decided to stop purchasing oil and natural gas from us, our revenue could decline and our operating results and financial condition could be harmed. However, we believe that the loss of any one or all of our major purchasers would not have a material adverse effect on our financial condition or results of operations, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

Transportation

During the initial development of our fields, we consider all gathering and delivery infrastructure options in the areas of our production which does not have an existing dedication. Our oil is transported from the wellsite tank batteries by truck to terminal pipeline sites or direct to a refinery. Our natural gas is generally transported by third-party gathering lines from the wellhead to a gas processing facility.

Natural Gas Dedication Agreements

We have dedicated our natural gas production from the oil and natural gas properties contributed by Citizen under an agreement with a third party. Under this dedication agreement, we are required to deliver our natural gas production from the contract area, as defined in the agreement, through November 2030. There is no specified volume or volume penalty in the agreement.

For the oil and natural gas properties contributed by Linn, we assumed Linn's dedication agreement with Blue Mountain, a subsidiary of Riviera. The agreement with Blue Mountain requires us to deliver our natural gas production from the contract area, as defined in the agreement, through November 2030. There is no specified volume or volume penalty in the agreement.

Volume Commitment

The substantial majority of our midstream agreements are structured as acreage dedications with no specified volume commitments. However, we do have one agreement with a third party that requires us to deliver a minimum volume of natural gas from a specified dedication area. In the event that we are unable to meet this natural gas volume delivery commitment, we would incur deficiency fees on any undelivered volumes as of November 2021. If we are unable to deliver any natural gas volumes subsequent to December 31, 2018 through November 2021, we will owe deficiency fees of $8.1 million at the end of the commitment period.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies, many of whom 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 and natural gas market prices. Our larger or more integrated competitors may be able to absorb the burden of complying with existing, and subsequently amended, 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 developing 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 complying with existing, and subsequently amended, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position.

Seasonality of Business

Weather conditions affect the demand for, and prices of, oil and natural gas. Demand for oil and natural gas 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.

Operating Hazards and Insurance

The oil and natural gas industry involves a variety of operating hazards and risks that could result in substantial losses from, among other things, injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, cleanup responsibilities, regulatory investigation and penalties, and suspension of operations. We may be liable for environmental damages caused by previous owners of property we purchase and lease. As a result, we may incur substantial liabilities to third parties or governmental entities, the payment of which could reduce or eliminate funds otherwise available, or result in the loss of properties. In addition, we participate in wells on a non-operated basis and therefore may be limited in our ability to control the risks associated with the operation of such wells.

In accordance with customary industry practices, we maintain insurance against some, but not all, potential losses. We cannot provide assurance that any insurance we obtain will be adequate to cover any losses or liabilities. We have elected to self-insure for certain items for which we have determined that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows. For more information about potential risks that could affect us, please see “Risk Factors.”

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 in our possession or 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 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 report.

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Oil and Natural Gas Leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 12.5% to 25.0%, resulting in a net revenue interest to us generally ranging from 74% to 81% of our working interest, with an average net revenue interest of 78.9%.

Regulation of the Oil and Natural 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 ("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 U.S. 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 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 and natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells. These laws and regulations may limit the amount of oil and natural gas we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, NGLs and natural gas 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 natural 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 oil, natural gas, condensate and NGLs are not currently regulated and are made at market prices. Although prices of these energy commodities are currently unregulated, the U.S. Congress historically has been active in their regulation. We cannot predict whether new legislation to regulate oil, natural gas, or the prices charged for these commodities might be proposed, what proposals, if any, might actually be enacted by the U.S. 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 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, 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 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 natural gas or the purchase or sale of transportation services subject to FERC's jurisdiction pursuant to the Energy Policy Act of 2005 ("EPAct 2005"). Under the EPAct 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 natural 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 natural 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. EPAct 2005 also gives FERC authority to impose civil penalties for violations of the NGA and the Natural Gas Policy Act of 1978 up to $1.0 million per day, per violation. The anti-manipulation rule applies to activities of otherwise non jurisdictional entities to the extent the activities are conducted "in connection with" natural 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, any market participant, including a producer that engages in certain wholesale sales or purchases of natural 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 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 natural 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 NGLs, 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 $1.2 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 swaps and futures contracts, is similar to the anti-manipulation authority granted to the FTC with respect to 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 Occupational Safety and Health Matters

Our operations are subject to stringent and complex federal, state and local laws and regulations governing occupational safety and health aspects of our operations, the discharge and disposal of materials into the environment and the protection of the environment and natural resources (including threatened and endangered species and their habitat). Numerous governmental entities, including the U.S. Environmental Protection Agency ("EPA") 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 exploration, drilling, water withdrawal, wastewater disposal and other regulated activities; (ii) restrict the types, quantities and concentration of various substances that can be disposed or released into the environment or injected into formations in connection with oil and natural gas drilling and production activities, and the manner of any such disposal, release, or injection; (iii) limit or prohibit our operations on certain lands lying within wilderness, wetlands and other protected areas, or require formal mitigation measures in such sensitive areas; (iv) require investigatory and remedial measures to mitigate pollution from former and on-going operations, such as requirements to close pits and plug abandoned wells; (v) impose 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, the imposition of investigatory, corrective or remedial obligations or the incurrence of capital expenditures, 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.

The trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment, and thus any changes in environmental laws and regulations or reinterpretation 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 releases or spills 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 releases or spills, including any third-party claims for damage to property, natural resources or persons. Continued compliance with existing requirements is not expected to materially affect us. However, there is no assurance that we will not incur substantial costs in the future related to revised or additional environmental laws and regulations that could have a material adverse effect on our business and operating results.

The following is a summary of the more significant existing and proposed environmental and occupational safety and health laws and regulations, 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. Pursuant to rules 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. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of oil and natural gas, if properly handled, are currently exempt from regulation as hazardous waste under RCRA and, instead, are regulated under RCRA's less stringent non-hazardous waste provisions, state laws or other federal laws. However, it is possible that certain oil and natural gas drilling and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. For example, in December 2016, the EPA and environmental groups 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. The consent decree requires EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and natural gas wastes or to sign a determination that revision of the regulations is not necessary. The agency missed the deadline, though review may still be ongoing. If the EPA proposes a rulemaking, the consent decree requires that EPA take final action by no later than July 15, 2021. Any such change could result in an increase in our as well as the oil and natural gas exploration and production industry's costs to manage and dispose of generated wastes, which could have a material adverse effect on our results of operations and financial position. In the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes.

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 of a hazardous substance occurred and anyone who disposed or arranged for the disposal of the hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several, strict 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 numerous properties that have been used for oil, natural gas and NGL exploration, production and processing for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off site 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 hazardous substances, wastes, or petroleum hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial operations to prevent future contamination, the costs of which could be substantial.

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 hazardous substances, into state waters and waters of the United States. The discharge of pollutants into regulated waters 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 plan requirements imposed under the CWA require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of 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. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

The CWA also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. The EPA and the U.S. Army Corps of Engineers ("Corps") published a final rule attempting to clarify the federal jurisdictional reach over waters of the United States ("WOTUS"). Several legal challenges to the rule followed, along with attempts to stay implementation of the WOTUS rule following the change in U.S. presidential administrations. Currently, the WOTUS rule is active in 22 states and enjoined in 28 states. However, in December 2018, the EPA and the Corps proposed changes to regulations under the CWA that would provide discrete categories of jurisdictional waters and tests for determining whether a particular waterbody meets any of those classifications. Several groups have already announced their intent to challenge the proposed WOTUS replacement rule. Therefore, the scope of jurisdiction under the CWA is uncertain at this time. To the extent either 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 can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

The primary federal law related specifically to oil spill liability is the Oil Pollution Act of 1990 ("OPA"), which amends and augments the oil spill provisions of the CWA and imposes certain duties and liabilities on certain responsible parties related to the prevention, containment and cleanup of oil spills and damages resulting from such spills in or threatening waters of the United States or adjoining shorelines. For example,
operators of certain oil and natural gas facilities must develop, implement and maintain facility response plans, conduct annual spill training for certain employees, use secondary containment systems to prevent spills from reaching nearby water bodies and provide varying degrees of financial assurance. The OPA subjects owners and operators of vessels, offshore facilities, and onshore facilities to strict, joint and several liability for oil removal costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. Although defenses exist, they are limited. As such, a violation of the OPA has the potential to adversely affect our operations.

Subsurface Injections and Induced Seismicity

In the course of our operations, we produce water in addition to oil, natural gas and NGLs. 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 federal Safe Drinking Water Act ("SDWA") and analogous state laws. The UIC program includes requirements for permitting, testing, monitoring, recordkeeping and reporting of injection well activities, as well as a prohibition against the migration of fluid containing any contaminant into underground sources of drinking water. State regulations require a permit from the applicable regulatory agencies to operate underground injection wells. Although we monitor the injection process of our wells, any leakage from the subsurface portions of the injection wells could cause degradation of fresh groundwater resources, potentially resulting in suspension of our UIC permit, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resources and imposition of liability by third parties claiming damages for alternative water supplies, property and personal injuries. 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.

Furthermore, in response to seismic events near belowground disposal wells used for the injection of produced water resulting from oil and natural gas activities, federal and some state agencies are investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such disposal wells. In response to these concerns, regulators in some states have adopted, and other states are considering adopting, additional requirements related to produced water disposal wells to improve seismic safety. For example, in Oklahoma, the Oklahoma Corporation Commission ("OCC") has implemented a variety of measures including the National Academy of Science's "traffic light system," pursuant to which the agency reviews new disposal well applications for proximity to faults, seismicity in the area and other factors in determining whether such wells should be permitted, permitted only with restrictions, or not permitted. The OCC also evaluates existing wells to assess their continued operation, or operation with restrictions, based on location relative to such faults, seismicity and other factors, with certain of such existing wells required to make frequent, or even daily, volume and pressure reports. In addition, the OCC has rules requiring operators of certain saltwater disposal wells in the state to, among other things, conduct mechanical integrity testing or make certain demonstrations of such wells' depth that, depending on the depth, could require the plugging back of such wells and/or the reduction of volumes disposed in such wells. As a result of these measures, the OCC, from time to time, has developed and implemented plans calling for wells within areas of interest where seismic incidents have occurred to restrict or suspend disposal well operations in an attempt to mitigate the occurrence of such incidents. For example, in February 2018 the OCC revised well completion seismicity guidelines to reduce the threshold of seismic readings required to suspend hydraulic fracturing operations in some circumstances. In addition, these seismic events have also led to an increase in tort lawsuits filed against exploration and production companies as well as the owners of underground injection wells.

Evaluation of seismic incidents and whether or to what extent those events are induced by the injection of produced water into disposal wells continues as governmental authorities consider new and/or past seismic incidents in areas where produced water disposal activities occur or are proposed to be performed. The adoption of any new laws, regulations, or directives that restrict our ability to dispose of water generated by production and development activities, whether by limiting volumes, disposal rates, disposal well locations or otherwise, or requiring us to shut down disposal wells, could have a material adverse effect on our business, financial condition, and results of operations. In addition, we could be subject to third-party lawsuits alleging damages resulting from seismic events that occur in our areas of operation.

Air Emissions

The federal Clean Air Act ("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 or limit the development of oil and natural gas projects. 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 the current standard of 75 ppb for the current 8 hour primary and secondary ozone standards to 70 ppb for both standards, and completed attainment/non-attainment designations in July 2018. States are expected to implement more stringent permitting and pollution control requirements as a result of this final rule, which could apply to our operations. While the EPA has determined that all counties in which we operate are in attainment with the new ozone standards, these determinations may be revised in the future. Reclassification of areas or imposition of more stringent standards may make it more difficult to construct new facilities or modify existing facilities in these newly designated non-attainment areas. In another example, in June 2016, the EPA finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of oil and natural gas projects and increase our costs of development and production, which costs could be significant.

Climate Change

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases (“GHGs”) present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration (“PSD”) construction and Title V operating permit reviews for certain large stationary sources that are already potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards that typically will be established by state agencies. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from certain onshore and offshore oil and natural gas production, processing, transmission and storage facilities in the United States.

There has not been significant activity in the form of federal legislation to reduce GHG emissions in recent years. In the absence of such federal climate legislation, a number of state and regional cap and trade programs have emerged that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. The EPA has also developed strategies for the reduction of methane emissions, including emissions from the oil and natural gas industry. For example, in June 2016, the EPA published New Source Performance Standards (“NSPS”) Subpart OOOOa requirements to reduce methane and volatile organic compound (“VOC”) emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities. Following the change in presidential administration, there have been attempts to modify these regulations, and litigation concerning the regulations is pending. In addition, the Bureau of Land Management (“BLM”) finalized a similar rule regarding the control of methane emissions in November 2016 that applies to oil and natural gas exploration and development activities on public and tribal lands. In September 2018, the BLM issued a final rule rescinding the agency’s 2016 methane rule, and litigation challenging the rescission is pending. As a result of the developments described above, substantial uncertainty exists with respect to implementation of the EPA and BLM methane rules. However, given the long-term trend towards increasing regulation, future federal GHG regulations of the oil and natural gas industry remain a possibility, and several states have separately imposed their own regulations on methane emissions from oil and natural gas production activities.

On an international level, the United States is one of almost 200 nations that, in December 2015, agreed to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets. The Paris Agreement was signed by the United States in April 2016 and entered into force on November 4, 2016; however, the Paris Agreement does not impose any binding obligations on its participants. In August 2017, the U.S. Department of State officially informed the United Nations of the United States' intent 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 reenter the Paris Agreement or a separately negotiated agreement are unclear at this time.

Although it is not possible at this time to predict how new laws or regulations in the United States or any legal requirements imposed by the Paris Agreement on the United States, should it not withdraw from the agreement, that may be adopted or issued to address GHG emissions would impact our business, any such future laws, regulations or legal requirements imposing reporting or permitting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations as well as result in 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 and natural gas we produce and lower the value of our reserves. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that oil and natural gas will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades. 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. Moreover, activist shareholders have introduced proposals that may seek to force companies to adopt aggressive emission reduction targets or to shift away from more carbon-intensive activities. While we cannot predict the outcomes of such proposals, they could ultimately make it more difficult to engage in exploration and production activities. Finally, it should be noted that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts and other extreme climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Hydraulic Fracturing Activities

Hydraulic fracturing is a practice in the oil and natural gas industry that is used to stimulate production of oil and natural gas 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 chemicals 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. However, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, in June 2016, the EPA published standards for the capture of air emissions released during oil and natural gas hydraulic fracturing, leak detection, and permitting and separately published an effluent limitation guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. Also, the BLM finalized rules in March 2015, establishing stringent standards relating to hydraulic fracturing on federal and American Indian lands. However, in December 2017, the BLM issued a final rule repealing the 2015 hydraulic fracturing rule. Litigation regarding this rescission is pending.

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, but, at this time, federal legislation related to hydraulic fracturing appears unlikely. At the state level, some states, including Oklahoma, have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, disclosure, operational or well construction requirements on hydraulic fracturing activities, or that prohibit hydraulic fracturing altogether. Local governments may also seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular.

If new laws or regulations that significantly restrict hydraulic fracturing are adopted at the local, state or federal level, we may incur additional costs to comply with such 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.

In addition to asserting regulatory authority, certain government agencies have conducted reviews focusing on environmental issues associated with hydraulic fracturing practices. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources “under certain limited circumstances.” Because the report did not find a direct link between hydraulic fracturing itself and contamination of groundwater resources, this years-long study report does not appear to provide any basis for further regulation of hydraulic fracturing at the federal level.

Endangered Species and Migratory Birds Considerations

The Endangered Species Act (“ESA”) and comparable state laws were established to protect endangered and threatened species and their habitat. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species’ habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act (“MBTA”). 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. For example, in November 2016, the U.S. Fish & Wildlife Service (“FWS”) completed initial reviews of a petition filed by environmental groups to list the Lesser Prairie Chicken as endangered and found substantial information that the petitioned action may be warranted. An assessment of the biological status of the Lesser Prairie Chicken began in 2015, and further action remains pending. Moreover, as a result of a 2011 settlement agreement, the FWS was required to make a determination on listing numerous species as endangered or threatened under the ESA by no later than completion of the agency’s 2017 fiscal year. The FWS missed the deadline and continues to review species for listing under the ESA. In addition, the federal government in the past has issued indictments under the MBTA to several oil and natural gas companies after dead migratory birds were found near reserve pits associated with drilling activities.

However, in December 2017, the Department of Interior issued a new opinion revoking its prior enforcement policy and concluded that an incidental take is not a violation of the MBTA. The identification or designation of previously unprotected species as threatened or endangered in areas where we operate could cause us to incur increased costs arising from species protection measures or could result in limitations on our development 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.

Occupational Safety and Health

We are subject to the requirements of the Occupational Safety and Health Act ("OSHA") and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA's Emergency Planning and Community Right to Know Act and comparable state statutes and any implementing regulations require that we organize 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.

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. 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.

Employees

As of December 31, 2018, we had 179 full-time employees. We hire independent contractors on an as-needed basis to perform various field and other services. We have no collective bargaining agreements with our employees. We believe that our employee relationships are satisfactory.

Facilities

Our principal executive offices are located at 14701 Hertz Quail Springs Pkwy, Oklahoma City, Oklahoma 73134, and our telephone number at that address is (405) 896-8050. Our website is located at www.roanresources.com.

Availability of Company Reports

We make our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, all amendments to those reports, and all other information filed with or furnished to the SEC, available, free of charge, through our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC.

ITEM 1A. RISK FACTORS

Risks Related to Our Business

Oil, natural gas and NGL prices are volatile. A 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, future rate of growth and carrying value of our properties. Oil, natural gas and NGLs are commodities, and their prices may fluctuate widely in response to relatively minor changes in market uncertainty and the supply of and demand for oil, natural gas and NGLs. Historically, oil, natural gas and NGL prices have been volatile and will likely continue to be volatile in the future. Beginning in the second half of 2014, oil and natural gas prices began a rapid and significant decline as global supply exceeded demand. This oversupply continued through the first half of 2016 and led to troughs in oil and natural gas prices, which at their lowest NYMEX prices were $27.45 per Bbl and $1.64 per MMBtu, respectively. Although average oil and natural gas prices increased in the first nine months of 2018, reaching levels as high as $76.41 per Bbl and $4.84 per MMBtu, respectively, they began to decline again in the fourth quarter of 2018 reaching levels as low as $44.48 per Bbl and $2.72 per MMBtu. Likewise, NGLs, which are made up of ethane, propane, isobutane, normal butane and natural gasoline, all of which have different uses and different pricing characteristics suffered significant declines in realized prices but also began to recover in the second half of 2017 and during the year ended December 31, 2018, reaching levels as high as $10.46 per MMBtu. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control that include, but are not limited to, the following:

- worldwide and regional political or economic conditions impacting the global supply and demand for oil, natural gas and NGLs;
- the level of global oil, natural gas and NGL exploration and production;
- the level of commodity storage inventories;
- political and economic conditions in or affecting other producing regions or countries, including the Middle East, Africa, South America and Russia;
- actions of the Organization of the Petroleum Exporting Countries, its members and other state-controlled oil companies relating to oil price and production controls;
- prevailing prices on local price indexes in the area in which we operate and expectations about future commodity prices;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- localized and global supply and demand fundamentals and transportation availability;
- the cost of exploring for, developing and producing reserves and transporting production;
- weather conditions and other natural disasters;
- technological advances affecting energy consumption and production;
- speculative trading in oil, natural gas and NGL markets;
- the price and availability of alternative fuels; and
- U.S. federal, state and local and non-U.S. governmental regulation and taxes.

Lower commodity prices may reduce our cash flows and borrowing ability. If we are unable to obtain needed capital or financing on satisfactory terms, our ability to develop our reserves could be adversely affected. Furthermore, using lower prices in estimating proved reserves may result in a reduction in proved reserve volumes due to economic limits. In addition, sustained periods with oil and natural gas prices at levels lower

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than current WTI or Henry Hub prices may adversely affect our drilling economics and our ability to raise capital, which may require us to re-evaluate and postpone or eliminate our development drilling, and result in the reduction of some of our proved undeveloped reserves and the net present value of our reserves. 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 further reduction or sustained decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, liquidity and ability to finance planned capital expenditures.

Our business requires substantial capital expenditures. We may be unable to generate sufficient cash from operations or obtain required capital or financing as needed or on acceptable terms, which could lead to a decline in our ability to access or grow production and reserves.

The oil and natural gas industry is capital-intensive. We currently make, and expect to continue making, substantial capital expenditures. We expect to fund our 2019 capital expenditures with cash generated by operations, borrowings under our credit facility and access to capital markets; however, our financing needs may require us to alter or increase our capitalization substantially through the incurrence of additional indebtedness or the issuance of debt or equity securities or the sale of assets. The incurrence of additional indebtedness would require that a portion of our cash flow from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flow from operations to fund working capital, capital expenditures and acquisitions. 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.

Our cash flow from operations and access to capital are subject to a number of variables that include, but are not limited to, the following:

- the prices at which our production is sold;
- our proved reserves;
- the volume and types of hydrocarbons we are able to produce from existing wells;
- our ability to acquire, locate and produce new reserves;
- the levels of our operating expenses; and
- our ability to borrow under our credit facility and our ability to access the capital markets.

If our revenues or the borrowing base under our credit facility decrease 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 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 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 could materially and adversely affect our business, financial condition and results of operations.

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

Our assets were contributed to Roan LLC in August 2017 by Linn and Citizen. Under management services agreements ("MSAs"), Linn and Citizen operated the contributed oil and natural gas assets on our behalf until May 2018, at which time our management team took over as operator of the contributed oil and natural gas properties. As a result, there is only limited historical financial and operational information available upon which to base your evaluation of our performance.

In addition, we have grown rapidly over the last year. 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.

Restrictions in our credit facility could limit our growth and our ability to engage in certain activities.

Our credit facility contains a number of significant covenants, including restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- incur liens;
- enter into mergers;
- sell assets;
- make investments and loans;
- make or declare dividends;
- enter into commodity hedges exceeding a specified percentage of our expected production or proved reserves;
- enter into interest rate hedges exceeding a specified percentage of our outstanding indebtedness; and
- engage in transactions with affiliates.

In addition, our credit facility requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios.

The restrictions in our credit facility 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 credit facility impose on us.

A breach of any covenant in our credit facility would result in a default under such facility after any applicable grace periods. A default, if not waived, could result in acceleration of the indebtedness outstanding under our credit facility and in a default with respect to, and an acceleration of, the indebtedness outstanding under any 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 on acceptable terms, if at all.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of 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. For example, as of December 31, 2018, we had $514.6 million of debt outstanding, with a weighted average interest rate of 5.21%, and a 1.0% increase in interest rates would result in an increase in annual interest expense of $5.1 million, assuming no change in the amount of debt outstanding. Recent and continuing 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.

Any significant reduction in our borrowing base under our credit facility as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations.

Our credit facility limits the amounts we can borrow up to a borrowing base amount, which the lenders, in their sole discretion, will determine semiannually on April 1st and October 1st of each year. The borrowing base will depend on, among other things, projected revenues from, and asset values of, the proved oil and natural gas properties securing our credit facility and hedging arrangements. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our credit facility. Any increase in the borrowing base will require the consent of the lenders holding 100% of the commitments.

In the future, we may not be able to access adequate funding under our credit facility as a result of a decrease in borrowing base due to the issuance of new indebtedness, the outcome of a subsequent borrowing base redetermination or an unwillingness or inability on the part of lending counterparties to meet their funding obligations if other lenders are unable to provide additional funding to cover any defaulting lender’s position. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such a case, we could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our drilling plan, make acquisitions or otherwise carry out business plans, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

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 applicable debt instruments, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including our credit facility, 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. 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 instruments 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 would likely result in a reduction of our credit rating, which 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. 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.

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 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 and natural gas 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 reserves may vary from our estimates. For instance, initial production rates reported by us or other operators may not be indicative of future or long-term production rates, our recovery efficiencies may be worse than expected, and production declines may be greater than we estimate and may be more rapid and irregular when compared to initial production rates. In addition, we may adjust reserve estimates to reflect additional production history, results of development activities, current commodity prices and other existing factors. Any significant variance could materially affect the estimated quantities and present value of our reserves.

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. Using lower prices in estimating proved reserves would likely result in a reduction in proved reserve volumes due to economic limits.

The standardized measure of our estimated reserves contained in this Annual Report and in the footnotes to our financial statements is not an accurate estimate of the current fair value of our estimated reserves.

Standardized measure is a reporting convention that provides a common basis for comparing oil and natural gas companies subject to the rules and regulations of the SEC. Standardized measure requires the use of specific pricing as required by the SEC, as well as operating and development costs prevailing as of the date of computation. Consequently, it may not reflect the prices ordinarily received or that will be received for oil and natural gas production because of varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the oil and natural gas properties. Accordingly, estimates included herein of future net cash flow may be materially different from the future net cash flows that are ultimately received. Therefore, the standardized measure of our estimated reserves included in this Annual Report should not be construed as accurate estimates of the current fair value of our proved reserves.

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

As of December 31, 2018, approximately 61% of our total estimated proved reserves were classified as proved undeveloped. Development of these proved undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves, increases in costs to drill and develop such reserves or decreases in commodity prices will reduce the value of our estimated PUDs 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 lose leases through expiration or could cause us to reclassify our PUDs as unproved reserves. Further, we may be required to write down our PUDs if we do not drill those wells within five years after their respective dates of booking.

Our future cash flows and results of operations are highly dependent on our ability to find, develop or acquire additional reserves.

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 exploration and development 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 our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, 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 materially and adversely affected.

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 development, acquisition and production 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 develop or purchase 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, please see “Risk Factors—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.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, which include, but are not limited to, the following:

- compliance with regulatory requirements, including those relating to water supply, discharge and disposal of waste water and other hazardous materials, emission of GHGs and limitations on 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;
- equipment failures, accidents or other unexpected operational incidents;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- adverse weather conditions;
- environmental hazards, such as oil and natural gas leaks, oil spills, fires or explosions, pipeline and tank ruptures and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- declines in oil and natural gas prices;
- limited availability of financing at acceptable terms;
- title problems; and
- limitations in the market for oil and natural gas.

Certain of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, environmental contamination or loss of wells and regulatory fines or penalties.

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

Accounting rules require that our proved oil and natural gas properties should be tested for recoverability whenever events or circumstances indicate that the carrying amount may not be recoverable. Based on prevailing commodity prices and specific market factors and circumstances at the time of prospective impairment tests, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write-down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings. We did not incur impairment charges of proved properties during the year ended December 31, 2018.

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

We enter into derivative instrument contracts for a portion of our oil and natural gas production. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of any 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.

If we enter into derivative instruments that require cash collateral, our cash otherwise available for use in our operations would be reduced. Any future collateral requirements will depend on financial and industry market conditions and arrangements with our counterparties. In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for oil and natural gas, which could also have a material adverse effect on our financial condition. Alternatively, higher oil and natural gas prices may result in significant non-cash fair value losses being incurred on our derivatives, which could cause us to experience net losses associated with those hedging contracts when oil and natural gas prices rise. Additionally, in times of low commodity prices, our ability to enter into additional commodity derivative contracts with favorable commodity price terms may be limited, which may adversely impact our future revenues and cash flows as compared to historical periods during which we were able to hedge our oil and natural gas production at higher prices.

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 the counterparty 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 asset positions generally increase, which increases our counterparty credit exposure. 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.

The enactment of derivatives legislation and the promulgation of regulations pursuant thereto, could have an adverse effect on our ability to use derivative instruments to reduce the effect of risks associated with our business.

The Dodd-Frank Act, enacted in 2010, establishes federal oversight and regulation of the OTC derivatives market and entities, like us, that participate in that market. Among other things, the Dodd-Frank Act required the CFTC to promulgate a range of rules and regulations applicable to OTC derivatives transactions, and these rules may affect both the size of positions that we may enter or the ability and willingness of counterparties to trade opposite us, potentially increasing costs for transactions. Moreover, such changes could materially reduce our hedging opportunities which could adversely affect our revenues and cash flow during periods of low commodity prices. While many Dodd-Frank Act regulations are already in effect, the rulemaking and implementation process is ongoing, and the ultimate effect of the adopted rules and regulations and any future rules and regulations on our business remains uncertain.

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 or counterparties with other businesses that subject them to regulation in foreign jurisdictions, we may become subject to or otherwise impacted by such regulations. At this time, the impact of such regulations is not clear.

We have an extensive inventory of future potential drilling locations that could be developed over an extended period of time, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to generate sufficient cash from operations or raise the substantial amount of capital that may be necessary to drill such locations.

Subject to our management determining an appropriate number of wells to drill per section from a spacing perspective, we expect to identify a large number of future drilling locations on our existing acreage. These drilling locations will represent a significant part of our growth strategy. Our ability to drill and develop these locations will depend 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, access to suitable surface drilling pad locations, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the drilling locations our management team identifies will ever be drilled or if we will be able to produce oil, natural gas or NGLs from these or any other drilling locations.

In addition, we may 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 or financing required to do so. Please see "—Our business requires substantial capital expenditures. We may be unable to generate sufficient cash from operations or obtain required capital or financing as needed or on acceptable terms, which could lead to a decline in our ability to access or grow production and reserves."

Approximately 16% 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 16% 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. Further, to the extent we determine that it is not economic to develop particular undeveloped acreage, we may intentionally allow leases to expire.

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

It is generally 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 leases and underlying mineral interest at the time of acquisition. Rather, we rely upon the judgment of lease brokers or landmen 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 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.

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

Our operations involve utilizing some of the latest drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling horizontal wells include, but are not limited to, the following:

- landing our wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running our casing the entire length of the wellbore; and
- 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, the following:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

In addition, certain of the new techniques we are adopting may cause irregularities or interruptions in production due to offset wells being shut in and the time required to drill and complete multiple wells before any such wells begin producing. Furthermore, the results of any drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no production history and, consequently, we are more limited in assessing future drilling results in these areas. If our drilling results are less than anticipated, the return on our investment for a particular project may not be as attractive as we anticipated, and we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

Multi-well pad drilling may result in volatility in our operating results.

We utilize multi-well pad drilling where practical. Because wells drilled on a pad are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location, multi-well pad drilling delays the commencement of production, which may cause volatility in our quarterly operating results.

We will not be the operator on all of our acreage or drilling locations, and, therefore, we will not be able to control the timing of exploration or development efforts, associated costs or the rate of production of any non-operated assets.

As of December 31, 2018, we had over 170,000 net acres in the Merge, STACK and SCOOP plays of the Anadarko Basin, approximately 71% of which we operated. As of December 31, 2018, we were the operator on 591 gross (449 net) of our 1,263 gross (502 net) producing wells. We will have limited ability to exercise influence over the operations of the drilling locations operated by our partners and there is the risk that our partners may at any time have economic, business or legal interests or goals that are inconsistent with ours. Furthermore, the success and timing of development activities operated by our partners will depend on a number of factors that will be largely outside of our control that include, but are not limited to, the following:

- the timing and amount of capital expenditures;

- the operator's expertise and financial resources;
- the approval of other participants in drilling wells;
- the selection of technology; and
- the rate of production of reserves, if any.

This limited ability to exercise control over the operations and associated costs of some of our drilling locations could prevent the realization of targeted returns on capital in drilling or acquisition activity.

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 NGLs. 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. Drought conditions have persisted in Oklahoma in past years. Although we have not been directly affected to date, these drought conditions have led governmental authorities in other areas of the state 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, or if we experience delays in obtaining water sourcing permits or other rights, we may be unable to economically produce oil, natural gas and NGLs, which could have a material and adverse effect on our financial condition, results of operations and cash flows.

Our producing properties are located in the Merge, STACK and SCOOP plays within the Anadarko Basin, in Oklahoma, making us vulnerable to risks associated with operating in a single geographic area.

All of our producing properties are geographically concentrated in the Merge, STACK and SCOOP plays within the Anadarko Basin in Central Oklahoma. At December 31, 2018, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we are disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or other drought-related conditions or interruption of the processing or transportation of oil, natural gas or NGLs.

The marketability and pricing of our production is dependent upon transportation and other facilities and various market factors, which we generally do not control. If these facilities are unavailable or we become subject to adverse pricing differentials, our operations could be interrupted and our revenues reduced.

The marketability of our oil, natural gas and NGL production depends in part upon the availability, proximity and capacity of transportation and other production facilities owned by third parties. Insufficient production from our wells to support the construction of pipeline facilities by our purchasers or a significant disruption in the availability of our or third-party transportation facilities or other production facilities could adversely impact our ability to produce or deliver to market our oil, natural gas and NGLs, causing a significant interruption in our operations. While we believe we have reserved sufficient capacity with third-party facilities to gather, process, fractionate and transport a significant portion of our projected production, that capacity may not be sufficient to handle all of our production, or these third-party facilities may experience delays in construction, mechanical problems or become unavailable to us due to unforeseen circumstances.

Additionally, we depend on various trucking providers for our oil production and on two third-party midstream companies for substantially all of our current natural gas and NGL production. Our current natural gas and NGL arrangements provide for pricing at Mont Belvieu, Texas, but future arrangements could be tied to pricing at Conway, Kansas or other market hubs and subject us to adverse pricing differentials. In the future, we may be required to find alternative markets and gathering, processing or fractionation arrangements for our production, and such alternative arrangements may only be available on unfavorable terms, or not at all. If we are unable, for any sustained period, to access these third-party facilities or find acceptable alternative arrangements, we may be required to shut in or curtail production. Any such shut in or curtailment, or an inability to obtain favorable terms for gathering, processing, fractionating and delivering the oil, natural gas and NGLs produced from our fields, would materially and adversely affect our financial condition and results of operations.

We are subject to acreage dedications and one of our current midstream contracts contains a minimum volume commitment.

We are currently party to midstream contracts that contain acreage dedications through November 2030. We have multiple dedications within certain of our operated sections. As a result, we are required to manage our production to ensure these commitments are satisfied. If we are unable to effectively manage these split dedications within a section with multiple dedications, we would be in breach of one of the midstream contracts, which could have an adverse effect on our business and financial condition.

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. We are currently party to a firm transportation agreement, which contains an aggregate minimum volume commitment of natural gas that is required to be delivered from a specific area by November 2021. Although we expect to meet the minimum volume delivery commitment under this contract, in the event that we are unable to fully satisfy this natural gas volume delivery commitment, we would incur deficiency fees. Lower commodity prices may lead to reductions in our drilling program, which may result in insufficient production to utilize our full firm transportation and processing capacity. 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 of operations.

Reliance upon a few large customers may adversely affect our revenue and operating results.

Our top four customers represented approximately 77% of our total revenue for the year ended December 31, 2018. It is likely that we will continue to derive a significant portion of our revenue from a relatively small number of customers for the foreseeable future. Loss of one of these purchasers could adversely affect our revenues in the short term.

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

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

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 development activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as unpermitted releases of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, air and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death;
- natural disasters; and
- terrorist attacks targeting oil and natural gas related facilities and infrastructure.

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. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Certain of our properties are subject to land use restrictions, which could limit the manner in which we conduct our business.

Certain of our properties are subject to land use restrictions, including city ordinances, which could limit the manner in which we conduct our business. Such restrictions could affect, among other things, our access to and the permissible uses of our facilities as well as the manner in which we produce oil and natural gas and may restrict or prohibit drilling in general. The costs we incur to comply with such restrictions may be significant in nature, and we may experience delays or curtailment in the pursuit of development activities

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

The demand for drilling rigs, pipe and other equipment and supplies, as well as 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 and natural gas prices, causing periodic shortages. As conditions in the oil and natural gas industry improve, demand for drilling rigs, equipment and personnel, as well as access to transportation, processing and refining facilities will likely increase, as will the costs for those items. Any delay or inability to secure the personnel, equipment, power, services, resources and facilities access necessary for us to engage in our anticipated development activities could negatively impact our production volumes. In addition, any such negative effect on production volumes, or significant increases in costs, could have a material adverse effect on our cash flow and profitability.

We could experience periods of higher costs if commodity prices rise. These increases could reduce our profitability, cash flow and ability to complete development activities as planned.

Historically, our capital and operating costs have risen during periods of increasing oil, natural gas and NGL prices. These cost increases result from a variety of factors beyond our control, such as increases in the cost of electricity, steel and other raw materials that we and our vendors rely upon; increased demand for labor, services and materials as drilling activity increases; and increased taxes. Decreased levels of drilling activity in the oil and natural gas industry in recent periods have led to declining costs of some drilling equipment, materials and supplies. However, such costs may rise faster than increases in our revenue if commodity prices rise, thereby negatively impacting our profitability, cash flow and ability to complete development activities as scheduled and on budget. This impact may be magnified to the extent that our ability to participate in the commodity price increases is limited by our derivative activities.

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

In the future we may make acquisitions of assets or businesses that complement or expand our current business. However, there is no guarantee we will be able to identify attractive acquisition opportunities. In the event we are able to identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms. Competition for acquisitions may also increase the cost of, or cause us to refrain from, completing acquisitions.

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 credit facility imposes certain limitations on our ability to enter into acquisition transactions. Our credit facility also limits our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses.

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

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. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

We may be subject to risks in connection with acquisitions of properties.

The successful acquisition of producing properties requires an assessment of several factors, including:

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

The accuracy of these assessments is inherently uncertain. 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 fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. 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.

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 subject to stringent federal, state and local laws and regulations related to environmental and occupational health and safety issues that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our operations are subject to numerous stringent and complex federal, state and local laws and regulations governing, among other things, occupational safety and health aspects of our operations, the discharge of materials into the environment (such as the venting or flaring of natural gas and the emission of GHGs and other air pollutants), the generation, management and disposal of solid or hazardous wastes and the protection of the environment and natural resources (including threatened and endangered species). These laws and regulations may impose numerous obligations applicable to our operations, including the acquisition of a permit or other approval 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, and reclamation and restoration costs. 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. Such enforcement actions often involve taking difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, natural resource damages, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations or specific projects and limit our growth and revenue.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations 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, including such spills and releases that occur in the future, could expose us to material losses, expenditures and liabilities under applicable environmental laws and regulations. Under certain of such laws and regulations, we could be subject to strict, joint and several liability for the investigation, removal or remediation of contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations, regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with previous standards in the industry at the time they were conducted. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. We may not be able to recover some or any of these costs from insurance.

The trend in environmental regulation has been towards more stringent requirements, 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. For example, in October 2015, the EPA issued a final rule under the CAA, lowering the NAAQS for ground level ozone from the current standard of 75 parts per billion (“ppb”) for the current 8 hour primary and secondary ozone standards to 70 ppb for both standards, and completed attainment/non-attainment designations in July 2018. States are expected to implement more stringent permitting and pollution control requirements as a result of this final rule, which could apply to our operations. While the EPA has determined that all counties in which we operate are in attainment with the new ozone standards, these determinations may be revised in the future. Reclassification of areas or imposition of more stringent standards may make it more difficult to construct new facilities or modify existing facilities in these newly designated non-attainment areas. Separately, in June 2016, the EPA finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities (such as tank batteries and compressor stations), on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements. Compliance with these and other more stringent air pollution control and permitting standards and other environmental regulations could delay or prohibit our ability to develop oil and natural gas projects and increase our costs of development and production, the costs of which could be significant. Please see “Business—Regulation of the Oil and Natural Gas Industry—Regulation of Environmental and Occupational Safety and Health Matters” for a further description of the laws and regulations that affect us.

Restrictions on drilling activities intended to protect certain species of wildlife and their habitat may adversely affect our ability to conduct drilling activities in 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 their habitat. 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. For example, in November 2016, FWS completed initial reviews of a petition filed by environmental groups to list the Lesser Prairie Chicken as endangered and found substantial information that the petitioned action may be warranted. An assessment of the biological status of the Lesser Prairie Chicken began in 2015, and further action remains pending. 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 activities that could have a material and adverse impact on our ability to develop and produce our reserves.

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 EPAct 2005, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to approximately $1.2 million per day for each violation. The 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 approximately $1.2 million per day, and the CFTC prohibits market manipulation in the markets regulated by the CFTC, including similar anti manipulation authority with respect to 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 approximately $1.1 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 Natural Gas Industry.”

Climate change laws and regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil, natural gas and NGLs that we produce while potential physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the CAA that, among other things, establish PSD construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that are already potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards that typically will be established by state agencies. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from specified large GHG emission sources in the United States, including certain onshore oil and natural gas production sources, which include certain of our operations. Recent federal regulatory action with respect to GHG emissions from the oil and natural gas sector has focused on methane emissions. For example, in June 2016, the EPA published performance standards, known as Subpart OOOOa for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities. Following the change in presidential administration, there have been attempts to modify these regulations, and litigation concerning the regulations is pending. The BLM also finalized a similar rule regarding the control of methane emissions in November 2016 that applies to oil and natural gas exploration and development activities on public and tribal lands. In September 2018, the BLM issued a final rule rescinding the agency’s 2016 methane rule, and litigation challenging the rescission is pending. As a result of the developments described above, substantial uncertainty exists with respect to implementation of the EPA and BLM methane rules. However, given the long-term trend towards increasing regulation, future federal GHG regulations of the oil and natural gas industry remain a possibility, and several states have separately imposed their own regulations on methane emissions from oil and natural gas production activities.

There has not been significant activity in the form of federal legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional cap and trade programs have emerged that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. On an international level, the United States is one of almost 200 nations that, in December 2015, agreed to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets (“Paris Agreement”). The Paris Agreement was signed by the United States in April 2016 and entered into force on November 4, 2016; however, the Paris Agreement does impose any binding obligations on its participants. In August 2017, the U.S. Department of State officially informed the United Nations of the United States’ intent 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 reenter the Paris Agreement or a separately negotiated agreement are unclear at this time.

Although it is not possible at this time to predict how new laws or regulations in the United States or any legal requirements imposed by the Paris Agreement on the United States, should it not withdraw from the agreement, that may be adopted or issued to address GHG emissions would impact our business, any such future laws, regulations or legal requirements imposing reporting or permitting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations as well as result in 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 NGLs we produce and lower the value of our reserves. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that oil and natural gas will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades. 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. Moreover, activist shareholders have introduced proposals that may seek to force companies to adopt aggressive emission reduction targets or to shift away from more carbon-intensive activities. While we cannot predict the outcomes of such proposals, they could ultimately make it more difficult to engage in exploration and production activities. Finally, it should be noted that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts, and other extreme climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Changes in the legal and regulatory environment governing the oil and natural gas industry, particularly changes in the current Oklahoma forced pooling system, could have a material adverse effect on our business.

Our business is subject to various forms of extensive government regulation, including laws and regulations concerning the location, spacing and permitting of the oil and natural gas wells we drill and the disposal of saltwater produced from such wells, among other matters. Changes in the legal and regulatory environment governing our industry, particularly any changes to Oklahoma statutory forced pooling procedures that make forced pooling more difficult to accomplish, could result in increased compliance costs and adversely affect our business and operating results.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities 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 oil and/or natural gas 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 chemicals 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. However, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, in June 2016, the EPA published standards for the capture of air emissions released during oil and natural gas hydraulic fracturing, leak detection, and permitting and separately published an effluent limitation guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain limited circumstances. In addition, the BLM finalized rules in March 2015 establishing stringent standards relating to 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. However, in December 2017, BLM issued a final rule repealing the 2015 hydraulic fracturing rule, and litigation regarding this rescission is pending.

Additionally, 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, but, at this time, federal legislation related to hydraulic fracturing appears unlikely. At the state level, some states, including Oklahoma, have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, disclosure, operational or well construction requirements on hydraulic fracturing activities, or that prohibit hydraulic altogether. Local governments may also seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular.

In the event that a new, federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we may incur additional costs to comply with such 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, which could in turn have a material adverse effect on our business and results of operations.

Please see “Business—Regulation of the Oil and Natural Gas Industry—Regulation of Environmental and Occupational Safety and Health Matters” for a further description of the laws and regulations that affect us.

Our use of 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, 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. As a result, our drilling activities may not be successful or economical. In addition, the use of advanced technologies, such as 3-D seismic data, requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures.

Legislation or regulatory initiatives intended to address seismic activity could restrict our drilling and production activities, as well as our ability to dispose of saltwater gathered from such activities, which could limit the Company’s ability to produce oil and natural gas economically and have a material adverse effect on our business.

State and federal regulatory agencies continue to study a possible connection between hydraulic fracturing related activities and the increased occurrence of seismic activity. We have experienced, and may in the future experience, seismic events in connection with our drilling and completion activities. Certain of these events, if above certain levels, may result in suspension of drilling or completion activities by the OCC. In response to these concerns, regulators in some states have adopted, and other states are considering adopting, additional requirements related to produced water disposal wells to improve seismic safety. For example, in Oklahoma, the OCC has implemented a variety of measures including the National Academy of Science’s “traffic light system,” pursuant to which the agency reviews new disposal well applications for proximity to faults, seismicity in the area and other factors in determining whether such wells should be permitted, permitted only with restrictions, or not permitted. The OCC also evaluates existing wells to assess their continued operation, or operation with restrictions, based on location relative to such faults, seismicity and other factors, with certain of such existing wells required to make frequent, or even daily, volume and pressure reports. In addition, the OCC has rules requiring operators of certain saltwater disposal wells in the state to, among other things, conduct mechanical integrity testing or make certain demonstrations of such wells’ depth that, depending on the depth, could require the plugging back of such wells and/or the reduction of volumes disposed in such wells. As a result of these measures, the OCC, from time to time, has developed and implemented plans calling for wells within areas of interest where seismic incidents have occurred to restrict or suspend disposal well operations in an attempt to mitigate the occurrence of such incidents. We dispose of large volumes of saltwater gathered from our drilling and production operations pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities. In addition, we could be subject to third-party lawsuits alleging damages resulting from seismic events that occur in our areas of operation. The adoption and implementation of any new laws, regulations or orders that restrict our ability to use hydraulic fracturing or dispose of saltwater gathered from our drilling and production activities could have a material adverse effect on our business, financial condition and results of operations.

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, and other disruptions.

As an oil, natural gas and NGL producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information 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 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.

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, natural gas and NGLs 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 Class A Common Stock

The requirements of being a public company, including compliance with the reporting requirements of 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.

As the successor registrant to Linn, we must comply with new laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002 (the "Sarbanes-Oxley Act"), related regulations of the SEC with which we were not required to comply as a private company. Complying with these statutes, regulations and requirements occupies a significant amount of time of our board of directors and management and significantly increases our costs and expenses. Compliance with these requirements 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.

In addition, 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. 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.

We are subject to certain requirements of Section 404 of the Sarbanes-Oxley Act. If we fail to comply with the requirements of Section 404 or if we identify and report material weaknesses in internal control over financial reporting, our investors may lose confidence in our reported information and our stock price may be negatively affected.

We are required to comply with certain provisions of Section 404 of the Sarbanes-Oxley Act. Section 404 requires that we document and test our internal control over financial reporting and issue our management's assessment of our internal control over financial reporting. Furthermore, while we generally must comply with Section 404 of the Sarbanes-Oxley Act for our fiscal year ended December 31, 2018, we are not required to have our independent registered public accounting firm attest to the effectiveness of our internal controls until we cease to be a non-accelerated filer. If we fail to comply with the requirements of Section 404 of the Sarbanes-Oxley Act, or if we identify and report material weaknesses in our internal control over financial reporting, the accuracy and timeliness of the filing of our annual and quarterly reports may be materially adversely affected and could cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our Class A common stock. In addition, a material weakness in the effectiveness of our internal control over financial reporting could result in an increased chance of fraud and the loss of customers, reduce our ability to obtain financing and require additional expenditures to comply with these requirements, each of which could have a material adverse effect on our business, results of operations and financial condition.

We have identified material weaknesses in our internal control over financial reporting; failure to achieve and maintain effective internal control over financial reporting could have a material adverse effect on our business.

We have identified material weaknesses in our internal control over financial reporting in connection with the audit of our financial statements as of and for the years ended December 31, 2018, 2017 and 2016. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

We have identified the following material weaknesses in our internal control over financial reporting.

We had an overall lack of qualified personnel within the organization who possessed an appropriate level of expertise, experience and training to effectively design, implement and maintain:

(i) Adequate controls to monitor and assess the control environment. Specifically, internal controls were not designed or operating effectively to ensure appropriate monitoring or assessment of the control environment, including utilizing an appropriate control framework.
(ii) Adequate controls to establish appropriate entity level controls. Specifically, internal controls were not designed or operating effectively to ensure a sufficient amount of entity level controls were in place and operating effectively.
(iii) Effective controls over our period-end financial reporting processes, including controls over the preparation, analysis and review of certain significant account reconciliations required to assess the appropriateness of account balances at period-end; and controls over segregation of duties and the review of manual journal entries. Specifically, we did not design and maintain effective controls to verify that journal entries were properly prepared with sufficient supporting documentation or were reviewed and approved to ensure the accuracy and completeness of the manual journal entries. Additionally, certain key accounting personnel have the ability to prepare and post journal entries, as well as review account reconciliations, without an independent review by someone other than the preparer.
(iv) Effective controls over information technology systems that are relevant to the preparation of the financial statements. Specifically, we did not design and maintain (a) user access controls to ensure appropriate segregation of duties and to adequately restrict user and privileged access to infrastructure, financial applications, programs, and data to appropriate personnel, (b) program change management controls to ensure that information technology program and data changes affecting financial IT applications and underlying accounting records are identified, tested, authorized and implemented appropriately, (c) computer operation controls to ensure all financially significant batch jobs are monitored for the completeness and accuracy of data transfer, and (d) program development controls to ensure that new software development is aligned with business and IT requirements. The deficiencies described in this clause (iv), when aggregated, could impact both maintaining effective segregation of duties and the effectiveness of IT-dependent controls (such as automated controls that address the risk of material misstatement to one or more assertions, along with the IT controls and underlying data that support the effectiveness of system-generated data and reports) that could result in misstatements potentially impacting all financial statement accounts and disclosures that would not be prevented or detected in a timely manner.
(v) Effective controls over our reservoir engineering process for estimating proved oil, natural gas and NGL reserves, which are used in the calculation of depletion of the Company’s oil and natural gas properties. Specifically, we did not maintain effective controls to verify that the Company’s ownership interests in its oil and natural gas properties used in the reservoir engineering process are sufficiently reviewed to ensure completeness and accuracy of the information.

(vi) A sufficient complement of resources with an appropriate level of accounting knowledge, experience and training to develop and maintain an effective internal control environment.

These material weaknesses did not result in any material misstatements of our financial statements or disclosures. The material weaknesses could, however, result in a misstatement of relevant account balances or disclosures that would result in a material misstatement to the annual or interim financial statements that would not be prevented or detected.

Because of these material weaknesses, management has concluded that the Company's internal control over financial reporting was not effective as of December 31, 2018.

We have taken and will continue to take a number of actions to remediate these material weaknesses. We are currently implementing measures designed to improve our internal control over financial reporting and remediate the control deficiencies that led to the material weaknesses, including but not limited to, (i) hiring additional IT and accounting personnel with appropriate technical skillsets, (ii) initiating design and implementation of our control environment, including the expansion of formal accounting and IT policies and procedures and financial reporting controls, (iii) conducting a company-wide assessment of our control environment, (iv) implementing appropriate review and oversight responsibilities within the accounting and financial reporting functions, and (v) evaluating controls over our information technology environment. We can give no assurance that these actions will remediate these material weaknesses in internal controls or that additional material weaknesses in our internal control over financial reporting will not be identified in the future. However, our failure to implement and maintain effective internal control over financial reporting could result in errors in our financial statements that could result in a restatement of our financial statements and cause us to fail to meet our reporting obligations.

The concentration of our capital stock ownership among our largest stockholders and their affiliates will limit your ability to influence corporate matters.

Our principal stockholders and their affiliates beneficially own approximately 75% (50% of which is beneficially owned by Roan Holdings) of our outstanding Class A common stock. Consequently, they will continue to have significant influence over all matters that require approval by our stockholders, including the election of directors and approval of significant corporate transactions. Because our board will be classified through the 2020 annual meeting, certain of our directors will not come up for election until after the 2020 annual meeting. This concentration of ownership and the rights of our principal stockholders will limit your ability to influence corporate matters, and as a result, actions may be taken that you may not view as beneficial.

In connection with the Reorganization, we entered into a stockholders' agreement with the principal stockholders. The stockholders' agreement provides the principal stockholders with the right to designate a certain number of nominees to our board of directors through the 2020 annual meeting so long as the principal stockholders and their affiliates collectively beneficially own certain amounts of the outstanding shares of our Class A common stock. The existence of significant stockholders 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, the concentration of stock ownership may adversely affect the trading price of our Class A common stock to the extent investors perceive a disadvantage in owning stock of a company with significant stockholders.

Furthermore, conflicts of interest could arise in the future between us, on the one hand, and our principal stockholders and their respective affiliates, including portfolio companies, on the other hand, concerning among other things, potential competitive business activities or business opportunities. Several of our principal stockholders are private equity firms or investment funds in the business of making investments in entities in a variety of industries. As a result, our principal stockholders’ existing and future portfolio companies may compete with us for investment or business opportunities. These conflicts of interest may not be resolved in our favor. Certain of our principal stockholders owning approximately 25% of our outstanding Class A common stock own a significant interest in Riviera, the owner of Blue Mountain.

Certain of our directors have significant duties with, and spend significant time serving, entities that may compete with us in seeking acquisitions and business opportunities and, accordingly, may have conflicts of interest in allocating time or pursuing business opportunities.

Certain of our directors, who are responsible for managing the direction of our operations and acquisition activities, hold positions of responsibility with other entities (including affiliates of our principal stockholders) that are in the business of identifying and acquiring oil and natural gas properties. The existing positions held by these directors may give rise to fiduciary or other duties that are in conflict with the duties they owe to us. These directors may become aware of business opportunities that may be appropriate for presentation to us as well as to the other entities with which they are or may become affiliated. Due to these existing and potential future affiliations, they may present potential business opportunities to other entities prior to presenting them to us, which could cause additional conflicts of interest. They may also decide that certain opportunities are more appropriate for other entities with which they are affiliated, and as a result, they may elect not to present those opportunities to us. These conflicts may not be resolved in our favor. Messrs. Taylor, Lederman and Bonanno serve on the board of directors of Riviera, the owner of Blue Mountain.

None of the principal stockholders, nor any of their respective affiliates are limited in their ability to compete with us, and the corporate opportunity provisions in our second amended and restated certificate of incorporation could enable each of them to benefit from corporate opportunities that might otherwise be available to us.

Our governing documents provide that our principal stockholders and each of their respective affiliates (including portfolio investments of any of them) are not restricted from owning assets or engaging in businesses that compete directly or indirectly with us. In particular, subject to the limitations of applicable law, our second amended and restated certificate of incorporation, among other things:

- permits such persons to conduct business that competes with us and to make investments in any kind of property in which we may make investments; and
- provides that if any of such persons or any employee, partner, member, manager, officer or director of any of such persons who is also one of our directors becomes aware of a potential business opportunity, transaction or other matter, they will have no duty to communicate or offer that opportunity to us.

Our principal stockholders or their respective affiliates may become aware, from time to time, of certain business opportunities (such as acquisition opportunities) and may direct such opportunities to other businesses in which they have invested, in which case we may not become aware of or otherwise have the ability to pursue such opportunity. Further, such businesses may choose to compete with us for these opportunities, possibly causing these opportunities to not be available to us or causing them to be more expensive for us to pursue. In addition, our principal stockholders or their respective affiliates may dispose of oil and natural gas properties or other assets in the future, without any obligation to offer us the opportunity to purchase any of those assets. As a result, our renouncing our interest and expectancy in any business opportunity that may be from time to time presented to our principal stockholders or their respective affiliates could adversely impact our business or prospects if attractive business opportunities are procured by such parties for their own benefit rather than for ours.

Our second amended and restated certificate of incorporation and second amended and restated 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 Class A common stock.

Our second amended and restated 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, it could be more difficult for a third party to acquire us. In addition, some provisions of our second amended and restated certificate of incorporation and second amended and restated 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;
- providing that the board of directors is expressly authorized to adopt, or to alter or repeal our second amended and restated bylaws; and
- establishing advance notice and certain information requirements for nominations for election to our board of directors or for proposing matters that can be acted upon by stockholders at stockholder meetings.

Our second amended and restated 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 second amended and restated 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 of 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 (the "DGCL"), our second amended and restated certificate of incorporation or our second amended and restated 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 second amended and restated 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 second amended and restated 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.

We do not intend to pay cash dividends on our Class A common stock, and our credit facility places certain restrictions on our ability to do so. Consequently, your only opportunity to achieve a return on your investment is if the price of our Class A common stock appreciates.

We do not plan to declare cash dividends on shares of our Class A common stock in the foreseeable future. Additionally, our credit facility places certain restrictions on our ability to pay cash dividends. Consequently, your only opportunity to achieve a return on your investment in us will be if you sell your Class A common stock at a price greater than you paid for it. There is no guarantee that the price of our Class A common stock that will prevail in the market will ever exceed the price that you paid for it.

Future sales of our Class A common stock in the public market, or the perception that such sales may occur, could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

We may sell additional shares of Class A common stock in one or more future public offerings. We may also issue additional shares of Class A common stock or securities convertible into Class A common stock. We have 152,539,532 outstanding shares of Class A common stock. We are authorized to issue 800,000,000 shares of Class A common stock and 50,000,000 shares of preferred stock with such designations, preferences and rights as determined by our board of directors. The potential issuance of such additional shares of equity securities will result in the dilution of the ownership interests of the holders of our Class A common stock and may create downward pressure on the trading price, if any, of our Class A common stock. The registration rights of the selling stockholders and the sales of substantial amounts of our Class A common stock following the effectiveness of shelf registration statements for the benefit of such holders, or the perception that these sales may occur, could cause the market price of our Class A common stock to decline and impair our ability to raise capital. We also may grant additional registration rights in connection with any future issuance of our capital stock.

We cannot predict the size of future issuances of our Class A common stock or securities convertible into Class A common stock or the effect, if any, that future issuances and sales of shares of our Class A common stock will have on the market price of our Class A common stock. Sales of substantial amounts of our Class A 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 Class A common stock.

We may issue preferred stock the terms of which could adversely affect the voting power or value of our Class A common stock.

Our second amended and restated 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 Class A 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 could adversely impact the voting power or value of our Class A 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 Class A common stock.

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

The trading market for our Class A common stock will be influenced by the research and reports that industry or securities analysts publish about us or our business. If 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 Class A common stock or if our operating results do not meet their expectations, our stock price could decline.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

We are party to lawsuits arising in the ordinary course of our business. We cannot predict the outcome of any such lawsuits with certainty, but management believes it is remote that pending or threatened legal matters will have a material adverse impact on our financial condition.

Due to the nature of our business, we are, from time to time, involved in other routine litigation or subject to disputes or claims related to our business activities, including workers' compensation claims and employment related disputes. In the opinion of our management, none of these other pending litigation, disputes or claims against us, if decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations.

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 listed on the New York Stock Exchange under the symbol "ROAN." As of March 27, 2019, our outstanding shares of 152,539,532 were held by 14 stockholders of record.

Dividend Policy

We have not declared or paid any cash dividends since our inception. We currently intend to retain future earnings, if any, to finance our operations and the growth of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon then-existing conditions, including our results of operations, financial condition, capital requirements, investment opportunities, statutory restrictions on our ability to pay dividends and other factors our board of directors may deem relevant. In addition, our credit facility places restrictions on our ability to pay cash dividends.

Sales of Unregistered Equity Securities

We did not have any sales of unregistered equity securities during the fiscal year ended December 31, 2018 that we have not previously reported on a Quarterly Report on Form 10-Q or a Current Report on Form 8-K.

Issuer Purchases of Equity Securities

During the three months ended December 31, 2018, there were no repurchases of our common shares.

Common Units Authorized for Issuance Under Equity Compensation Plan

See Item 12. “Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters” for information regarding securities authorized for issuance under equity compensation plans.

ITEM 6. SELECTED FINANCIAL DATA

Roan Inc. was incorporated in September 2018 to serve as a holding company and, prior to the Reorganization, had no previous operations, assets or liabilities. The historical financial information included in this selected financial data (i) on and after September 24, 2018, is that of Roan Inc., and (ii) prior to September 24, 2018, is that of Roan LLC, our predecessor. The historical financial and operational information of Roan LLC presented in this document, (i) prior to August 31, 2017, the date of the completion of the Contribution is that of Citizen, the predecessor of Roan LLC for financial reporting purposes and (ii) on and after August 31, 2017, is that of Roan LLC. Therefore, the historical financial and operational information of Citizen prior to August 31, 2017 does not include financial information relating to the oil and natural gas assets contributed to Roan LLC by Linn in connection with the Contribution.

This section presents our selected historical consolidated financial data for the periods indicated. The following selected financial data should be read in conjunction with Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements and related notes, each of which is included elsewhere in this Annual Report.

	Years Ended December 31,				
	2018	2017	2016	2015	2014(1)
	(in thousands, except per share amounts)				
Statements of Operations Data					
Total revenues	$517,821	$159,588	$54,965	$5,685	$206
Total costs and expenses	293,278	139,683	47,932	5,298	535
Income (loss) from operations	224,543	19,905	7,033	387	(329)
Interest expense	(8,352)	(1,461)	(86)	—	—
Other income	—	13	—	4	2
Income (loss) before income taxes	216,191	18,457	6,947	391	(327)
Income tax expense(2)	356,862	—	—	—	—
Net (loss) income	$(140,671)	$18,457	$6,947	$391	$(327)
Earnings (loss) per common share					
Basic	$(0.92)	$0.18	$0.11	$0.02	$(0.04)
Diluted	$(0.92)	$0.18	$0.11	$0.02	$(0.04)
Weighted average common shares outstanding(3)					
Basic	152,232	100,473	62,394	20,251	8,322
Diluted	152,232	100,473	62,394	20,251	8,322

(1) Includes financial information from July 1, 2014 to December 31, 2014. Citizen, the predecessor of Roan LLC, was formed on July 1, 2014

(2) As described above, Roan Inc. was formed in conjunction with the Reorganization. Roan Inc. is a corporation, and, as a result, is subject to U.S. federal, state and local income taxes. Our predecessor, Roan LLC, was treated as a flow-through entity for income tax purposes. As a result, the net taxable income or loss of Roan LLC and any related tax credits, for income tax purposes, flowed through to its members. Accordingly, no tax provision was made in the historical financial statements of Roan LLC since the income tax was an obligation of its members.

(3) For 2017, 2016, 2015 and 2014, amounts reflect the weighted average number of shares of common stock outstanding based on retrospectively reflecting the impact of the Reorganization.

	December 31,				
	2018	2017	2016	2015	2014
	(in thousands)				
Balance Sheet Data					
Cash and cash equivalents	$6,883	$1,471	$6,853	$22,814	$1,583
Oil and natural gas properties, net	$2,397,497	$1,798,644	$298,378	$81,476	$14,508
Total assets	$2,749,109	$1,885,592	$363,083	$113,053	$16,618
Current liabilities	$365,473	$203,344	$66,594	$13,638	$1,076
Long-term debt	$514,639	$85,339	$20,000	$—	$—
Total equity	$1,495,034	$1,584,769	$274,247	$98,292	$15,126

	Years Ended December 31,				
	2018	2017	2016	2015	2014
	(in thousands)				
Cash Flow Data					
Net cash provided by operating activities	$268,296	$60,275	$36,140	$4,637	$166
Net cash used in investing activities	$(689,092)	$(212,521)	$(241,109)	$(66,181)	$(14,036)
Net cash provided by financing activities	$426,208	$146,864	$189,008	$82,775	$15,453

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 thereto appearing elsewhere in this Annual Report. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are subject to risk and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the development, production, gathering and sale of oil, natural gas and NGLs. Please refer to Part I, Item 1A. “Risk Factors” and “Cautionary Statement Regarding Forward-Looking Statements” for additional information regarding these risks and uncertainties. In light of these risks and uncertainties, 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 natural gas company focused on the development of our assets throughout the eastern and southern Anadarko Basin. The Anadarko Basin, which spans from south-central Oklahoma to the northeast corner of the Texas panhandle, is one of the largest and most prolific onshore oil and natural gas basins in the United States, featuring multiple producing horizons and extensive well production history demonstrated over seven decades of development. We focus our development on formations where we believe we can apply our technical and operational expertise in order to increase production and cash flow to deliver compelling economic rates of return on a risk adjusted basis. Our objective is to maximize shareholder value and corporate returns by generating steady production growth, strong pre-tax margins and significant cash flow. Our acreage position is concentrated in areas that we believe demonstrate higher percentage production of oil and NGLs within the Merge play and provides us development opportunities through multiple stacked prospective development horizons.

How We Evaluate Our Operations

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

- actual and projected reserve and production levels;
- realized prices on the sale of oil, natural gas and NGLs, including the effect of our commodity derivative contracts;
- lease operating expenses; and
- capital expenditures on our oil and natural gas properties.

Factors That Significantly Affect Comparability of Our Financial Condition and Results of Operations

Corporate Reorganization

On September 24, 2018, we completed the Reorganization, where Roan LLC, our accounting predecessor, became a wholly-owned subsidiary of Roan Inc. Roan Inc. was incorporated to serve as a holding company and, prior to the Reorganization, had no previous operations, assets or liabilities.

The historical financial and operating information included in this Annual Report, (i) on and after September 24, 2018, is that of Roan Inc., and (ii) prior to September 24, 2018, is the information of Roan LLC, our accounting predecessor. The historical financial and operating information of Roan LLC presented here, (i) prior to August 31, 2017, the date of the completion of the Contribution is that of Citizen, the predecessor of Roan LLC for financial reporting purposes and (ii) on and after August 31, 2017, is that of Roan LLC. Therefore, the operating information of Citizen prior to August 31, 2017 does not include financial information relating to the oil and natural gas properties contributed by Linn.

Public Company Expenses

Subsequent to the Reorganization, we incur direct, incremental general and administrative ("G&A") expenses as a result of being a publicly traded company, including but not limited to, costs associated with hiring new personnel, Sarbanes-Oxley compliance, implementation of compensation programs that are competitive with our public company peer group, costs associated with annual and quarterly reports and our other filings with the SEC, exchange listing fees, tax return preparation, independent auditor fees, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs and independent director compensation. These direct, incremental G&A expenses are not included in our historical results of operations.

Income Taxes

As a result of the Reorganization, we became subject to federal and state tax. Due to the change in tax status, we have recorded a tax provision for the initial recording of the deferred tax liability recognized as a result of the Reorganization. Our accounting predecessor, Roan LLC, was treated as a flow-through entity for income tax purposes. As a result, the net taxable income or loss of Roan LLC and any related tax credits, for income tax purposes, flowed through to its members. Accordingly, no tax provision was made in the historical financial statements of Roan LLC since the income tax was an obligation of its members.

Impact of ASC Topic 606 Adoption

Revenue for the year ended December 31, 2018 reflects the adoption of ASC 606 on January 1, 2018. The adoption of ASC 606 requires certain costs that were previously recorded as gathering, processing and

transportation expenses to be accounted for as a deduction from revenue. We elected the modified retrospective method of transition. Accordingly, comparative information has not been adjusted and continues to be reported under the previous revenue standard. For a discussion of the impact of the adoption of ASC 606 on the Company's current period results as compared to the previous revenue recognition standards, see Note 3 – Revenue from Contracts with Customers.

Financial and Operational Performance

Our financial and operational performance for the year ended December 31, 2018 included the following highlights:

- Net loss was $140.7 million for the year ended December 31, 2018, as compared to net income of $18.5 million for the year ended December 31, 2017. The net loss was primarily due to:

- $30.7 million increase in production expenses, primarily related to an increase in production volumes in 2018;
- $86.5 million increase in depreciation, depletion, amortization and accretion, primarily due to increased production volumes and a higher depletion rate due to increases in capital expenditures during 2018;
- $29.5 million increase in general & administrative expenses, primarily due to salaries and benefits to our employees and equity-based compensation expense during the year ended December 31, 2018; and
- $356.9 million of income tax expense during the year ended December 31, 2018, which includes $304.5 million resulting from the initial deferred tax liability recognized upon becoming a taxable entity after the Reorganization.

Partially offset by:

- $273.4 million increase in oil, natural gas and NGL sales, primarily as a result of an increase in total production volumes during the year ended December 31, 2018; and
- $78.1 million gain on derivative contracts for the year ended December 31, 2018 primarily as a result of lower oil prices at December 31, 2018.

- Average daily sales volumes were 43.7 MBoe for the year ended December 31, 2018, an increase of 170% compared to 16.2 MBoe during 2017.
- Drilled or participated in 214 gross (72 net) wells with first production during 2018.
- 1,263 gross (502 net) producing wells online at December 31, 2018, including 591 gross (449 net) operated wells.

Sources of Revenue

Our revenues are derived from the sale of our oil and natural gas production, including the sale of NGLs that are extracted from our natural gas during processing. Revenues from product sales are a function of the volumes produced, product quality, market prices, and gas Btu content. Under our major gas dedication agreements, we have the ability to elect ethane recovery or rejection on a monthly basis. An election of ethane recovery typically results in higher NGL volumes and lower realized NGL prices while ethane rejection typically results in lower NGL volumes and higher realized NGL prices. Our revenues from oil, natural gas and NGL sales do not include the effects of derivatives. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices. The following table presents the sources of our revenues, excluding the effects of our derivative contracts, for the years presented:

	Years Ended December 31,		
	2018	2017	2016
Revenues			
Oil sales (1)	63%	46%	56%
Natural gas sales (1)	17%	30%	29%
Natural gas liquid sales (1)	20%	24%	15%

(1) Revenue for the year ended December 31, 2018 reflects the adoption of ASC 606 on January 1, 2018. The adoption of ASC 606 requires certain costs that were previously recorded as gathering, processing and transportation expenses to be accounted for as a deduction from revenue. We elected the modified retrospective method of transition. Accordingly, comparative information has not been adjusted and continues to be reported under the previous revenue standard.

Principal Components of Our Cost Structure

Production expenses. Production expenses are the costs incurred in the operation and maintenance of producing properties. Expenses for compression, direct labor, saltwater disposal and materials and supplies comprise the most significant portion of our production expenses. Certain operating cost components, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges, but can fluctuate depending on activities performed during a specific period. For instance, repairs to our pumping equipment or surface facilities or subsurface maintenance result in increased production expenses in periods during which they are performed. Certain operating cost components, such as compression and salt water disposal associated with completion water, are variable and increase or decrease as hydrocarbon production levels and the volume of completion water disposal increases or decreases. For example, as production rates and associated completion water flowback decrease over time, we optimize compression horsepower and decrease our completion water disposal costs.

We monitor our well performance and associated operating costs to determine if any wells or properties should be shut in, recompleted or sold. One measure by which we evaluate operating costs is production expenses per Boe. This per unit measure also allows us to monitor these costs to identify trends and to benchmark against other producers. Although we strive to reduce our production expenses, these expenses can increase or decrease on a per unit basis as a result of various factors as we operate our properties or make acquisitions and dispositions of properties. For example, we may increase field level expenditures to optimize our operations, incurring higher expenses in one quarter relative to another, or we may acquire or dispose of properties that have different production expenses per Boe. These initiatives would influence our overall operating cost and could cause fluctuations when comparing production expenses on a period-to-period basis.

Gathering, transportation and processing. Prior to adoption of ASC 606, gathering, transportation and processing expenses principally consist of expenditures to prepare and gather production from the wellhead, gas processing costs and transportation to a specified sales point. These costs are mainly driven by increases or decreases in unprocessed natural gas production volumes. As a result of the adoption of ASC 606 in 2018, these costs are accounted for as a deduction from revenue in the 2018 period.

Production taxes. Production taxes are paid on produced oil, natural gas and NGLs based on a percentage of revenues at fixed rates established by federal, state or local taxing authorities. In general, the production taxes we pay correlate to changes in our oil, natural gas and NGL revenues. As all of our oil and natural gas production is in the state of Oklahoma, we are generally subject to a tax rate of 2% for the first 36 months of production and 7% thereafter for wells spud on or after July 1, 2015. Starting with July 2018 production, the tax rate increased to 5% for the first 36 months of production and 7% thereafter. We are also subject to ad valorem taxes in the counties where our production is located. Ad valorem taxes are generally based on the valuation of our oil and natural gas properties, which also trend with oil and natural gas prices and vary across the different counties in which we operate.

Exploration expenses. These are primarily geological and geophysical costs that include seismic survey costs, amortization of the costs of unproved properties assessed for impairment on a group basis, costs of carrying and retaining unproved properties, and costs related to unsuccessful leasing efforts.

Depreciation, depletion, amortization and accretion. Depreciation, depletion and amortization is the systematic expensing of the capitalized costs incurred to acquire, explore and develop oil, natural gas and NGLs. All costs incurred in the acquisition, exploration and development of properties (excluding costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes and overhead related to exploration activities) are capitalized. Capitalized costs are depleted using the units of production method.

Accretion expense relates to our asset retirement obligations (“ARO”). We record the fair value of the legal liability for ARO in the period in which the liability is incurred (at the time the wells are drilled or acquired) at the asset’s inception, with the offsetting increase to property cost. The liability accretes each period until it is settled or the well is sold, at which time the liability is removed.

General and administrative. G&A expenses include corporate overhead such as payroll and benefits for our corporate staff, equity-based compensation cost, office rent for our headquarters, audit and other fees for professional services and legal compliance. G&A expenses are reported net of recoveries from other owners in properties operated by us and amounts capitalized pursuant to the successful efforts method. We expect that we will incur additional general and administrative expenses as a result of being a publicly-traded company.

Realized Prices on the Sales of Oil, Natural Gas and NGL Volumes

Our results of operations are heavily influenced by commodity prices. Commodity prices may fluctuate widely in response to (i) relatively minor changes in the supply of and demand for oil, natural gas and NGLs, (ii) market uncertainty and (iii) a variety of additional factors that are beyond our control. From time to time, we enter into derivative arrangements for our oil and natural gas production to mitigate the impact of price volatility on our business. See Item 7A. “Quantitative and Qualitative Disclosures About Market Risk – Commodity Price Risk” for further discussion of the risks related to commodity price exposure and our derivative contracts.

Pricing for certain of our natural gas contracts are based on Oklahoma indexes, including ONEOK Gas Transportation ("OGT"), Natural Gas Pipeline Company of America Mid-Continent ("NGPL MC"), Panhandle Eastern Pipeline ("PEPL") and Southern Star Central Gas Pipeline ("SSCGP") due to the proximity of those pipelines to our producing properties. These indexes fluctuate from Henry Hub pricing due to a variety of reasons including the distance to the retail market, availability and capacity of pipelines to move the product to distribution hubs, customer demand, and competition between suppliers.

Oil and natural gas prices have been subject to significant fluctuations during the past several years. The average oil and natural gas prices were higher during the year ended December 31, 2018 compared to the years ended 2017, and 2016. The following table sets forth the average NYMEX oil and natural gas prices for the years ended December 31, 2018, 2017, and 2016:

	Years Ended December 31,		
	2018	2017	2016
Average NYMEX prices			
Oil (Bbl)	$64.74	$50.95	$43.32
Natural gas (MMcf)	$3.28	$3.10	$2.61

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Results of Operations

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

The following table presents selected financial and operating information for the periods presented.

	Years Ended December 31,	
	2018	2017
Production Data		
Oil (MBbls)	4,364	1,454
Natural gas (MMcf)	41,890	17,582
Natural gas liquids (MBbls)	4,592	1,524
Total volumes (MBoe)	15,938	5,908
Average daily total volumes (MBoe/d)	43.7	16.2
Average Prices - as reported (1)		
Oil (per Bbl)	$63.07	$52.87
Natural gas (per Mcf)	$1.82	$2.80
Natural gas liquids (per Bbl)	$19.27	$26.44
Total (per Boe)	$27.59	$28.16
Average Prices - including impact of derivative contract settlements (1)		
Oil (per Bbl)	$55.87	$53.57
Natural gas (per Mcf)	$1.73	$2.89
Natural gas liquids (per Bbl)	$19.60	$26.44
Total (per Boe)	$25.50	$28.60
Average Prices - excluding gathering, transportation and processing costs (2)		
Oil (per Bbl)	$63.11	$52.87
Natural gas (per Mcf)	$2.29	$2.80
Natural gas liquids (per Bbl)	$24.83	$26.44
Total (per Boe)	$30.46	$28.16

(1) Average prices for the year ended December 31, 2018 reflect the adoption of ASC 606 on January 1, 2018. The adoption of ASC 606 requires certain costs that were previously recorded as gathering, processing and transportation expenses to be accounted for as a deduction from revenue. We elected the modified retrospective method of transition. Accordingly, comparative information has not been adjusted and continues to be reported under the previous revenue standard.

(2) Excludes the effects of netting gathering, transportation and processing costs under ASC 606.

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Revenues

The following table provides information on our operating revenues:

	Years Ended December 31,	
	2018	2017
	(in thousands)	
Revenues		
Oil sales (1)	$275,239	$76,876
Natural gas sales (1)	76,056	49,211
Natural gas liquid sales (1)	88,472	40,298
Gain (loss) on derivative contracts	78,054	(6,797)
Total revenues	$517,821	$159,588

(1) Revenue for the year ended December 31, 2018 reflects the adoption of ASC 606 on January 1, 2018. The adoption of ASC 606 requires certain costs that were previously recorded as gathering, processing and transportation expenses to be accounted for as a deduction from revenue. We elected the modified retrospective method of transition. Accordingly, comparative information has not been adjusted and continues to be reported under the previous revenue standard.

Oil sales. Our oil sales increased by approximately $198.4 million, or 258%, to $275.2 million for the year ended December 31, 2018 from $76.9 million for the year ended December 31, 2017. This increase was primarily due to the increase in production as well as the increase in average sales prices received for our produced volumes. Our oil production increased 2,910 MBbls, or 200%, to 4,364 MBbls for the year ended December 31, 2018 from 1,454 MBbls for the year ended December 31, 2017. The increase in production volumes was due to production associated with oil and natural gas properties contributed by Linn in August 2017 and drilling activity in the fourth quarter of 2017 and throughout 2018. The increase in average sales prices received on our oil production for the year ended December 31, 2018 reflects the increase in the index price for oil in 2018 as compared to 2017.

Natural gas sales. Our natural gas sales increased by approximately $26.8 million, or 55%, to $76.1 million for the year ended December 31, 2018 from $49.2 million for the year ended December 31, 2017. This increase was primarily due to the increase in production, partially offset by a decrease in average sales prices received for those produced volumes and the impact of netting transportation costs with revenue as a result of adopting ASC 606. Our natural gas production increased 24,308 MMcf, or 138%, to 41,890 MMcf for the year ended December 31, 2018 from 17,582 MMcf for the year ended December 31, 2017. The increase in production volumes was due to production associated with oil and natural gas properties contributed by Linn in August 2017 and drilling activity in the fourth quarter of 2017 and throughout 2018. The decrease in average sales prices received on our natural gas production for the year ended December 31, 2018 reflects the decrease in the Oklahoma index prices we received under our contract terms for natural gas in 2018 as compared to 2017. Additionally, our average sales price for the year ended December 31, 2018 was reduced by transportation costs for the produced natural gas volumes.

NGL sales. Our NGL sales increased by approximately $48.2 million, or 120%, to $88.5 million for the year ended December 31, 2018 from $40.3 million for the year ended December 31, 2017. This increase was primarily due to the increase in production, partially offset by a decrease in the average sales prices received for those produced volumes and the impact of netting transportation costs with revenue as a result of adopting ASC 606. Our NGL production increased 3,068 MBbls, or 201%, to 4,592 MBbls for the year ended December 31, 2018 from 1,524 MBbls for the year ended December 31, 2017. The increase in production volumes was

due to production associated with oil and natural gas properties contributed by Linn in August 2017 and drilling activity in the fourth quarter of 2017 and throughout 2018. The decrease in our average sales price for the year ended December 31, 2018 was primarily a result of transportation costs for the produced NGL volumes being netted against revenue.

Gain (loss) on derivative contracts. For the year ended December 31, 2018, changes in oil prices had a positive impact on the fair value of our derivative contracts. We had a gain on derivative contracts of $78.1 million, including a loss on settlement of derivatives contracts of $33.3 million and a favorable change in the fair value of derivative contracts of $111.4 million. For the year ended December 31, 2017, changes in oil prices had a negative impact on the fair value of our derivative contracts. We had a loss on derivative contracts of $6.8 million, including an unfavorable change in the fair value of derivative contracts of $9.5 million partially offset by $2.7 million gain on settlement of natural gas and oil derivative contracts in 2017. Included in the $2.7 million gain on settlement of natural gas and oil contracts in 2017 was a $1.3 million gain on the settlement of derivative contracts prior to their contractual maturity.

Operating Expenses

The following table provides information on our operating expenses:

	Years Ended December 31, 2018	2017
	(in thousands, except costs per Boe)	
Operating Expenses		
Production expenses	$47,600	$16,872
Gathering, transportation and processing (1)	—	18,602
Production taxes	17,579	3,685
Exploration expenses	43,303	32,629
Depreciation, depletion, amortization and accretion	123,922	37,376
General and administrative (2)	60,874	31,357
Gain on sale of oil and natural gas properties	—	(838)
Total	$293,278	$139,683
Average Costs per Boe		
Production expenses	$2.99	$2.86
Gathering, transportation and processing (1)	—	3.15
Production taxes	1.10	0.62
Exploration expenses	2.72	5.52
Depreciation, depletion, amortization and accretion	7.78	6.33
General and administrative (2)	3.82	5.31
Gain on sale of oil and natural gas properties	—	(0.14)
Total	$18.41	$23.65

(1) Gathering, transportation and processing for the year ended December 31, 2018 reflects the adoption of ASC 606 on January 1, 2018. The adoption of ASC 606 requires certain costs that were previously recorded as gathering, processing and transportation expenses to be accounted for as a deduction from revenue. We elected the modified retrospective method of transition. Accordingly, comparative information has not been adjusted and continues to be reported under the previous revenue standard.

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(2) General and administrative expenses for the years ended December 31, 2018 and 2017 include $11.0 million, or $0.69 per Boe, and $0.4 million, or $0.06 per Boe of equity-based compensation expense, respectively.

Production expenses. Production expenses were $47.6 million, or $2.99 per Boe, for the year ended December 31, 2018, which was an increase of $30.7 million, or 182%, from $16.9 million, or $2.86 per Boe, for the year ended December 31, 2017. The increase in production expenses during 2018 compared to 2017 was primarily due to increased production.

Gathering, transportation and processing. Gathering, transportation, and processing costs were $18.6 million, or $3.15 per Boe, for the year ended December 31, 2017. As a result of adopting ASC 606 in January 2018, these costs are reflected as a deduction from revenue for the year ended December 31, 2018.

Production taxes. Production taxes were $17.6 million for the year ended December 31, 2018, an increase of $13.9 million, or 377%, from $3.7 million for the year ended December 31, 2017. Production taxes primarily increased due to increased revenues and increased production tax rates, which became effective in July 2018.

Exploration expenses. For the year ended December 31, 2018, exploration expenses of $43.3 million included amortization of unproved leasehold of $36.0 million and geological and geophysical expenses of $7.3 million. For the year ended December 31, 2017, exploration expenses of $32.6 million consisted of unproved leasehold amortization of $19.6 million, impairment on unproved property of $4.5 million and geological and geophysical expenses of $7.3 million. Unproved leasehold amortization is calculated by considering our drilling plans and the lease terms of our existing unproved properties. The increase in exploration expenses is due, in part, to amortization of unproved leasehold associated with the oil and natural gas properties contributed by Linn.

Depreciation, depletion, amortization and accretion. Depreciation, depletion, amortization and accretion was $123.9 million, or $7.78 per Boe, for the year ended December 31, 2018, and $37.4 million, or $6.33 per Boe, for the year ended December 31, 2017, which is an increase of $86.5 million or 232%. The increase in depreciation, depletion, amortization and accretion was primarily due to increased production and, to a lesser extent, an increase in the depletion rate for our oil and natural gas properties. The per Boe increase in the depletion rate is attributable to higher capital expenditures in 2018.

General and administrative. General and administrative expenses were $60.9 million, or $3.82 per Boe, for the year ended December 31, 2018, an increase of $29.5 million or 94% from $31.4 million, or $5.31 per Boe, for the year ended December 31, 2017. During the year ended December 31, 2018, general and administrative expenses included salaries and benefits of $21.7 million and equity-based compensation expense of $11.0 million. Additionally, we incurred consulting and professional fees as part of the implementation of systems and processes and transition efforts in 2018 as well as $4.6 million of costs associated with the Reorganization. These expenses were offset by bonuses paid by Citizen of approximately $9.0 million during the year ended December 31, 2017.

Other Expenses

Interest expense, net. Interest expense, net of capitalized interest, for the year ended December 31, 2018 was $8.4 million as compared to $1.5 million for the year ended December 31, 2017. This increase was due to increased borrowings outstanding during the year ended December 31, 2018 as compared to the year ended December 31, 2017.

Income tax expense. Income tax expense for the year ended December 31, 2018 was $356.9 million and includes $304.5 million related to the recognition of a deferred tax liability upon becoming a taxable entity in conjunction with the Reorganization. The remainder of the income tax expense related to the applicable effective tax rate on taxable income after the Reorganization.

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

	Years Ended December 31,	
	2017	2016
Production Data		
Oil (MBbls)	1,454	739
Natural gas (MMcf)	17,582	6,382
Natural gas liquids (MBbls)	1,524	546
Total volumes (MBoe)	5,908	2,349
Average daily total volumes (MBoe/d)	16.2	6.4
Average Prices - as reported		
Oil (per Bbl)	$52.87	$41.36
Natural gas (per Mcf)	$2.80	$2.52
Natural gas liquids (per Bbl)	$26.44	$15.21
Total (per Boe)	$28.16	$23.40
Average Prices - including impact of derivative contract settlements		
Oil (per Bbl)	$53.57	$41.36
Natural gas (per Mcf)	$2.89	$2.52
Natural gas liquids (per Bbl)	$26.44	$15.21
Total (per Boe)	$28.60	$23.40

Revenues

Our operating revenues are primarily from the sale of oil, natural gas and NGLs. The following table provides information on our operating revenues:

	Years Ended December 31,	
	2017	2016
	(in thousands)	
Revenues		
Oil sales	$76,876	$30,565
Natural gas sales	49,211	16,093
Natural gas liquid sales	40,298	8,307
Loss on derivative contracts	(6,797)	—
Total revenues	$159,588	$54,965

Oil sales. Our oil sales increased by approximately $46.3 million, or 152%, to $76.9 million for the year ended December 31, 2017 from $30.6 million for the year ended December 31, 2016. This increase was primarily due to increased production and an increase in the average sales price received for our produced volumes. Our oil production increased by 715 MBbls, or 97%, for the year ended December 31, 2017 compared with the year ended December 31, 2016. The increase in production volumes was due to production associated with oil and natural gas properties contributed by Linn in August 2017 and drilling activity in 2017. The increase in average sales prices received on our oil production for the year ended December 31, 2017 reflects the increase in the index price for the year ended December 31, 2017 as compared to the year ended December 31, 2016.

Natural gas sales. Our natural gas sales increased by approximately $33.1 million, or 206%, to $49.2 million for the year ended December 31, 2017 from $16.1 million for the year ended December 31, 2016. This increase was due to increased production and an increase in average sales prices received for our produced volumes. Our natural gas production increased by 11,200 MMcf, or 175%, for the year ended December 31, 2017 compared with the year ended December 31, 2016. The increase in production volumes was due to production associated with oil and natural gas properties contributed by Linn in August 2017 and drilling activity in 2017. The increase in average sales prices received on our natural gas production for the year ended December 31, 2017 reflects the increase in the index price for the year ended December 31, 2017 as compared to the year ended December 31, 2016.

NGL sales. Our NGL sales increased by approximately $32.0 million, or 385%, to $40.3 million for the year ended December 31, 2017 from $8.3 million for the year ended December 31, 2016. This increase was primarily due to increased production as well as an increase in average sales prices received for our produced volumes. Our NGL production increased by 978 MBbls, or 179%, for the year ended December 31, 2017 compared with the year ended December 31, 2016. The increase in production volumes was due to production associated with oil and natural gas properties contributed by Linn in August 2017 and drilling activity in 2017. The increase in average sales prices received on our NGL production for the year ended December 31, 2017 reflects the increase in the index prices for NGLs in 2017.

Loss on derivative contracts. For the year ended December 31, 2017, changes in oil prices had a negative impact on the fair value of our derivative contracts. We had a loss on derivative contracts of $6.8 million, including unfavorable change in the fair value of derivative contracts of $9.5 million partially offset by $2.7 million gain on settlement of natural gas and oil derivative contracts in 2017. Included in the $2.7 million gain on settlement of natural gas and oil contracts in 2017 was a $1.3 million gain on the settlement of derivative contracts prior to their contractual maturity. There were no derivative contracts in place during the year ended December 31, 2016.

Operating Expenses

Our operating expenses reflect costs incurred in the development, production and sale of oil, natural gas and NGLs. The following table provides information on our operating expenses:

	Years Ended December 31,	
	2017	2016
	(in thousands, except per Boe)	
Operating Expenses		
Production expenses	$16,872	$5,090
Gathering, transportation and processing	18,602	5,920
Production taxes	3,685	1,087
Exploration expenses	32,629	5,258
Depreciation, depletion, amortization and accretion	37,376	24,996
General and administrative [(1)]	31,357	5,581
Gain on sale of oil and natural gas properties	(838)	—
Total	$139,683	$47,932
Average Costs per Boe		
Production expenses	$2.86	$2.17
Gathering, transportation and processing	3.15	2.52
Production taxes	0.62	0.46
Exploration expenses	5.52	2.24
Depreciation, depletion, amortization and accretion	6.33	10.64
General and administrative [(1)]	5.31	2.38
Gain on sale of oil and natural gas properties	(0.14)	—
Total	$23.65	$20.41

(1) General and administrative expenses for the year ended December 31, 2017 include $0.4 million, or $0.06 per Boe, of equity-based compensation expense.

Production expenses. Production expenses were $16.9 million, or $2.86 per Boe, for the year ended December 31, 2017, which was an increase of $11.8 million, or 231%, from $5.1 million, or $2.17 per Boe, for the year ended December 31, 2016. The increase in production expenses during 2017 compared to 2016 was primarily due to increased production.

Gathering, transportation and processing. Gathering, transportation, and processing costs were $18.6 million, or $3.15 per Boe, for the year ended December 31, 2017, which was an increase of $12.7 million, or 215%, from $5.9 million, or $2.52 per Boe, for the year ended December 31, 2016. The increase in gathering, transportation and processing costs during 2017 as compared to 2016 was primarily related to increased production.

Production taxes. Production taxes were $3.7 million for the year ended December 31, 2017, which was an increase of $2.6 million, or 239%, from $1.1 million for the year ended December 31, 2016. Production taxes primarily increased due to increased revenues.

Exploration expenses. For the year ended December 31, 2017, exploration expenses of $32.6 million consisted of unproved leasehold amortization of $19.6 million, impairment on unproved property of $4.5 million and geological and geophysical expenses of $7.3 million. For the year ended December 31, 2016, exploration expenses of $5.3 million consisted of impairment expense recognized related to our unproved properties. The increase in exploration expenses is due, in part, to amortization of unproved leasehold associated with the oil and natural gas properties contributed by Linn and costs associated with seismic information acquired in 2018.

Depreciation, depletion, amortization and accretion. Depreciation, depletion, amortization and accretion was $37.4 million, or $6.33 per Boe, for the year ended December 31, 2017, which was an increase of $12.4 million, or 50%, from $25.0 million, or $10.64 per Boe, for the year ended December 31, 2016. The increase in depreciation, depletion, amortization and accretion was primarily due to increased production.

General and administrative. General and administrative expenses were $31.4 million, or $5.31 per Boe, for the year ended December 31, 2017, which was an increase of $25.8 million, or 462%, from $5.6 million, or $2.38 per Boe, for the year ended December 31, 2016. During the year ended December 31, 2017, general and administrative expenses included fees paid to Citizen and Linn under our MSAs of $10.0 million, bonuses paid by Citizen of approximately $9.0 million, equity-based compensation expense of $0.4 million and professional and consulting expenses related to Roan's transition and system implementation.

Other Expenses
Interest expense. Interest expense for the year ended December 31, 2017 was $1.5 million as compared to $0.1 million for the year ended December 31, 2016. This increase was due to increased borrowings outstanding during 2017 as compared to 2016.

Liquidity and Capital Resources

Our primary sources of liquidity have been borrowings under our credit facility and cash flows from operations. Our primary uses of capital have been for the exploration, development and acquisition of oil and natural gas properties.

Cash Flows

Our cash flows for the year ended December 31, 2018, 2017, and 2016 are presented below:

	Years Ended December 31,		
	2018	2017	2016
	(in thousands)		
Net cash provided by operating activities	$268,296	$60,275	$36,140
Net cash used in investing activities	(689,092)	(212,521)	(241,109)
Net cash provided by financing activities	426,208	146,864	189,008
Net increase (decrease) in cash and cash equivalents	$5,412	$(5,382)	$(15,961)

Analysis of Cash Flow Changes Between the Year Ended December 31, 2018 and 2017

Cash flows provided by operating activities. Cash flows provided by operating activities for the year ended December 31, 2018 were $268.3 million compared to $60.3 million for the year ended December 31, 2017. The increase in cash flows provided by operating activities is primarily related to increased revenues partially offset by higher cash expenses due to increased activity in 2018.

Cash flows used in investing activities. Cash flows used in investing activities for the year ended December 31, 2018 were $689.1 million compared to $212.5 million for the year ended December 31, 2017. The increase in cash flows used in investing activities is due to the increase in capital expenditures on oil and natural gas properties resulting from the increase in drilling and completion activities in 2018 compared to 2017.

Cash flows provided by financing activities. Cash flows provided by financing activities for the year ended December 31, 2018 were $426.2 million compared to $146.9 million for the year ended December 31, 2017. The increase in cash flows provided by financing activities for the year ended December 31, 2018 is attributable to borrowings of $429.3 million from our credit facility. Financing activities for the year ended December 31, 2017 were related to capital contributions from Citizen members of $95.6 million and borrowings of $105.3 million, partially offset by repayments of $40.0 million on Citizen's credit facility and $11.1 million of distributions to Citizen members.

Analysis of Cash Flow Changes Between the Year Ended December 31, 2017 and 2016

Cash flows from operating activities. Cash flows from operating activities for the year ended December 31, 2017 were inflows of $60.3 million compared to inflows of $36.1 million for the year ended December 31, 2016. The increase in operating cash flows is primarily related to changes in working capital items and increased revenues partially offset by higher cash expenses.

Cash flows from investing activities. During the years ended December 31, 2017 and 2016, we completed acquisitions of oil and natural gas properties of $42.7 million and $144.8 million, respectively. Additionally, we invested $167.1 million and $96.3 million during the years ended December 31, 2017 and 2016, respectively, for development of oil and natural gas properties.

Cash flows from financing activities. Cash flows from financing activities for the year ended December 31, 2017, were attributable to borrowings of $105.3 million and contributions from Citizen members of $95.6 million, partially offset by $40.0 million repayment of borrowings on Citizen's credit facility and $11.1 million of distributions to Citizen members. Financing activities for the year ended December 31, 2016 were related to capital contributions of $169.0 million and $20.0 million of proceeds from borrowings.

Credit Facility

On September 5, 2017, we entered into our credit facility with Citibank, N.A., as administrative agent, and a syndicate of lenders, which matures on September 5, 2022 (our "credit facility"). Our credit facility, as amended, provides for commitments of $750.0 million. As of December 31, 2018, the borrowing base was set at $675.0 million. Redetermination of the borrowing base occurs semiannually on or about October 1 and April 1. As of December 31, 2018, we had $514.6 million of outstanding borrowings and no letters of credit outstanding under the credit facility.

Amounts borrowed under the credit facility bear interest at London Interbank Offered Rate ("LIBOR") or the alternate base rate ("ABR") at our election. The rate used for ABR loans is based on the higher of the prime rate, the federal funds effective rate plus 0.50% or the one-month LIBOR rate plus 1%. Either rate is adjusted upward by an applicable margin (ranging from 2.00% to 3.00% for LIBOR and 1.00% to 2.00% for ABR), based on the utilization percentage of the credit facility. Additionally, the credit facility provides for a commitment fee of 0.375% to 0.50% based on utilization, which is payable at the end of each calendar quarter.

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 the sale of property, mergers, consolidations and other similar transactions covenants; (iii) limitations on investments, loans and advances covenants; and (iv) limitations on dividends, distributions, redemptions and restricted payments covenants. Additionally, we are prohibited from hedging in excess of (a) 80% of reasonably anticipated projected production for the first thirty (30) month rolling period (based upon our internal projections) and (b) 80% of reasonably anticipated projected production from proved reserves for the second thirty (30) month rolling period of such sixty (60) month period (based on the most recently delivered reserve report). If the amount of borrowings outstanding exceed 50% of the borrowing base, we are required to hedge a minimum of 50% of the future production expected to be derived from proved developed reserves for the next eight quarters per our most recent reserve report.

The credit facility also contains financial covenants requiring us to comply with a leverage ratio of consolidated debt to consolidated EBITDAX (as defined in the credit agreement) for the period of four fiscal quarters then ended of not more than 4.00 to 1.00 and a current ratio of consolidated current assets to consolidated current liabilities (as defined in the credit agreement to exclude non-cash assets and liabilities under ASC Topic 815 Derivatives and Hedging and ASC Topic 410 Asset Retirement and Environmental Obligations) as of the fiscal quarter ended of not less than 1.00 to 1.00.

As of December 31, 2018, we were in compliance with the covenants under the credit facility.

Capital Expenditures

Our primary needs for cash are development, exploration and acquisition of oil and natural gas assets, payment of contractual obligations and working capital obligations. Funding for these cash needs may be provided by any combination of internally-generated cash flow and financing under our credit facility.

During the year ended December 31, 2018, capital expenditures for drilling and completion costs were $705.2 million. Capital expenditures for our operated properties are largely discretionary and within our control. We could choose 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 and natural gas, 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. We will continue to monitor commodity prices and overall market conditions and can adjust our rig cadence up or down in response to changes in commodity prices and overall market conditions.

Our capital budget for 2019 is $520 million to $570 million. Our capital expenditures are expected to be more heavily weighted to the first half of the year as a result of increased completion activity as we develop our inventory of drilled, uncompleted wells from 2018 drilling activity.

Based upon current oil and natural gas prices and production expectations for 2019, we believe our cash flow from operations, cash on hand, borrowings under our credit facility and access to capital markets will be sufficient to fund our operations for the next twelve months. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties.

Working Capital

At December 31, 2018, we had a working capital deficit of $42.2 million compared to $121.2 million at December 31, 2017. Current assets and current liabilities increased by $241.2 million and $162.1 million, respectively, at December 31, 2018, compared to December 31, 2017 as a result of us taking over in May 2018 as operator on the oil and natural gas properties contributed to us by Citizen and Linn and increased drilling activity during 2018. Additionally, at the conclusion of the MSAs, we assumed certain working capital accounts associated with these properties from Citizen and Linn. Another factor contributing to the decrease in the working capital deficit is the favorable position of our open derivative contracts with maturity dates within the next twelve months at December 31, 2018 compared to December 31, 2017.

Contractual Obligations

The following table summarizes our contractual obligations and commitments as of December 31, 2018:

	Payments Due by Period						
	2019	2020	2021	2022	2023	Thereafter	Total
	(in thousands)						
Credit Facility	$—	$—	$—	$514,639	$—	$ —	$514,639
Interest expenses related to Credit Facility (1)	27,201	27,201	27,201	18,482	—	—	100,085
Pipe and equipment purchase commitments (2)	1,455	—	—	—	—	—	1,455
Office building leases	1,692	2,047	2,136	2,229	456	171	8,731
Drilling rig commitments (3)	15,352	—	—	—	—	—	15,352
Total contractual obligations and commitments	$45,700	$29,248	$29,337	$535,350	$456	$ 171	$640,262

(1) Includes interest expense on our outstanding borrowings calculated using the weighted average interest rate of 5.21% at December 31, 2018.
(2) Reflects commitments to purchase specified amounts of pipe and equipment.
(3) Reflects future minimum drilling fees including early termination fees as specified by the contract.

The above table does not include liabilities related to ARO. These are costs associated with the plugging of wells and the related abandonment of oil and natural gas properties. Estimating the future ARO requires management to make estimates and judgments regarding timing and existence of a liability that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment.

Critical Accounting Policies and Estimates

The financial statements reflect a number of significant estimates that impact the carrying values of assets and liabilities and reported amounts of revenue and expenses. We make these estimates based on historical experience and on other judgments and assumptions that we believe are reasonable under the circumstances. The results of these estimates, judgments and assumptions form the basis for our determinations as to the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates under different assumptions or conditions.

We consider an accounting policy to be critical when it requires the most difficult, subjective and/or complex judgments by management regarding estimates about matters that are highly uncertain. We believe that the following critical accounting policies reflect our more significant estimates and assumptions used in the preparation of our financial statements.

Reserves

Proved reserves are based on the quantities of oil, natural gas and NGL that 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. Our reserve estimates as of December 31, 2018 were prepared by DeGolyer and MacNaughton, our independent reserve engineers, and our internal staff. DeGolyer and MacNaughton prepared reserve estimates for 93% of our total reserves.

Estimates of proved oil, natural gas and NGL reserves are used in the calculation of depletion of our oil and natural gas properties and impairment, if any, of proved oil and natural gas properties. As a result, changes in estimated quantities of our proved reserves could impact our reported financial results as well as disclosures regarding the quantities and value of proved oil and natural gas reserves. The process performed by the independent engineers to prepare reserve amounts included their estimation of reserve quantities, future production rates, future net revenue and the present value of such future net revenue, based in part on data we provided. The estimates of reserves conform to the guidelines of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years.

The accuracy of reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various economic assumptions and the judgments of the individuals preparing the estimates. In addition, reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of oil, natural gas and NGL eventually recovered.

Revenue Recognition

Revenues from the sale of oil, natural gas and NGLs are recognized when control of the product has been transferred to the customer, all performance obligations have been satisfied and collectability is reasonably assured. We recognize revenues from the sale of oil, natural gas and NGLs based on our share of volumes sold. If our aggregate sales volumes for a well are greater (or less) than our proportionate share of production from the well, a liability (or receivable) is established to the extent there are insufficient proved reserves available to make up the overproduced (or under produced) imbalance.

We adopted ASU 2014-09, ASC 606 on January 1, 2018 using a modified retrospective transition approach whereby changes have been applied for periods commencing after December 31, 2017 and prior period results have not been adjusted to conform to current presentation.

Under the new rules, revenues and transportation expenses associated with the natural gas and NGL production from our operated properties are now reported on a net basis compared to gross presentation in our historical periods.
For non-operated properties, we receive a net payment from the operator for our share of sales proceeds which is net of transportation costs incurred by the operator, if any. Such non-

operated revenues are recognized at the net amount of proceeds received, consistent with our historical practice.

Business Combinations

We account for all business combinations using the acquisition method, which involves the use of significant judgment. In 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.

We estimate the fair values of assets acquired and liabilities assumed in a business combination using various assumptions (all of which are predominately Level 3 inputs within the fair value hierarchy). The most significant assumptions typically relate to the estimated fair values assigned to proved and unproved oil and natural gas properties. To estimate the fair values of the proved and unproved oil and natural gas properties, we develop estimates of oil, natural gas and NGL reserves. Estimates of reserves are based on the quantities of oil, natural gas and NGLs that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. Additionally, a risk factor is applied to reserves by reserve type based on industry standards. We estimate future prices to apply to the estimated net quantities of reserves based on the applicable ownership percentage acquired and estimate future operating and development costs to arrive at estimates of future net cash flows. 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.

Oil and Natural Gas Properties

We follow the successful efforts method to account for our exploration and production activities. Under this method, costs incurred to purchase, lease, or otherwise acquire a property, whether unproved or proved, are capitalized when incurred. We initially capitalize exploratory well costs pending a determination 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 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.

Other exploration costs, including geological and geophysical costs, delay rentals and administrative costs associated with unproved property and unsuccessful exploratory well costs are expensed as incurred. Additionally, costs to operate and maintain wells and field equipment are expensed as incurred.

Depletion of capitalized drilling and development costs of producing oil and natural gas properties are computed using the unit-of-production method on a field level basis, based on total estimated proved developed oil, natural gas and NGL reserves. We determined our oil and natural gas properties are comprised of one single field. Proved leasehold costs associated with proved reserves are depleted based on total proved reserves, which includes proved undeveloped reserves. Under the unit-of-production method, oil and natural gas volumes are considered produced once they have been measured through meters at custody transfer or sales transaction points at the outlet valve on the lease or field storage tank.

Unproved properties and the related costs are transferred to proved properties when reserves are discovered on, or otherwise attributed, to the property.

The net carrying values of retired, sold or abandoned proved properties that constitute less than a complete unit of depletable property are charged, 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 to earnings. Gains or losses from the disposal of complete units of depletable property are recognized in earnings.

Proceeds from sales of all or a partial interest in individual unproved properties assessed for impairment on a group basis are accounted for as a recovery of costs. No gain or loss is recognized unless the sales proceeds exceed the original cost of the entire interest in the property, in which a gain will be recognized for the excess.

Impairment of Oil and Natural Gas Properties

Proved oil and natural gas properties are evaluated for impairment when facts or circumstances indicate that the carrying value of those assets may not be recoverable, such as when there are declines in oil and natural gas prices or well performance. In performing this assessment, assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. An impairment loss is indicated if the sum of the estimated undiscounted future cash flows related to an asset group is less than the carrying value of that asset group. If an impairment loss has been incurred, the loss recognized is the excess of the carrying amount over the estimated fair value.

We calculate the estimated fair value using a discounted future cash flow model. Management’s assumptions associated with the calculation of future cash flows include oil and natural gas prices based on NYMEX futures price strips, as well as other assumptions, including (i) pricing adjustments for differentials, (ii) production costs, (iii) capital expenditures, (iv) production volumes, (v) timing of development, and (vi) estimated reserves. A discount rate, consistent with that used by market participants, is applied to the estimated future cash flows in order to estimate fair value. Cash flow estimates for impairment testing exclude the effects of derivative instruments.

It is reasonably possible that the estimate of undiscounted future net cash flows may change in the future resulting in the need to impair carrying values. The primary factors that may affect estimates of future cash flows are (i) oil and natural gas futures prices, (ii) increases or decreases in production and capital costs, (iii) future reserve adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves, and (iv) results of future drilling activities.

Our unproved properties are assessed for impairment annually, or more frequently if events or changes in circumstances dictated that the carrying value of those assets may not be recoverable. Unproved leasehold costs are amortized on a group basis if individually insignificant, and a valuation allowance is established with a monthly amortization charge to exploration expense for the portion of the properties’ total cost that management estimates may never be transferred to proved properties during the terms of the respective leases. The impairment amortization rate considers our current drilling plans, the remaining terms of the respective leases and the results of exploratory drilling activity, and can be affected by economic factors including oil and natural gas price outlooks, projected capital costs, and available liquidity.

Costs of expired or relinquished leases are charged against the valuation allowance.

Derivative Instruments

We have entered into commodity derivative instruments to reduce the effect of price changes on a portion of our future oil and natural gas production.

The commodity derivative instruments are measured at fair value and are included in the balance sheet as derivative assets and derivative liabilities, on a net basis by counterparty. We adjust the valuations from the valuation model for nonperformance risk and for counterparty risk. The fair values of our commodity derivative instruments are calculated using industry standard models using assumptions and inputs which are substantially observable in active markets throughout the full term of the instruments. These include market price curves, contract terms and prices, credit risk adjustments, implied market volatility and discount factors. We have not designated any of the derivative contracts as fair value or cash flow hedges for accounting purposes for any of the periods presented. Accordingly, net gains and losses on commodity derivative instruments are recorded based on the changes in the fair values of the derivative instruments and are included in gain (loss) on derivative contracts in the consolidated statements of operations. Our cash flow is impacted when the settlements under the commodity derivative contracts result in making or receiving a payment to or from the counterparty and are reflected as operating activities in our consolidated statements of cash flows. Our firm sales contracts qualify for the normal purchase and normal sale exception. Contracts that qualify for this treatment do not require mark-to-market accounting treatment.

Equity-Based Compensation

In December 2017 and during 2018 prior to the Reorganization, we granted certain employees performance share units (“PSUs”) pursuant to the Roan Resources LLC Management Incentive Plan (the “MIP”). PSUs issued under the MIP were recognized as equity awards based on their characteristics. The compensation measurement was based on the grant date fair value of the award. The fair value of the PSUs is determined at the date of grant and is not remeasured. We determined the fair value of the PSUs based on an estimate of the fair value of our equity using an income approach. We used a discounted cash flow method to value the estimated future cash flows at an appropriate discount rate. For PSUs, compensation value is measured on the grant date using payout values derived from a Monte-Carlo valuation model. Estimates used in the Monte Carlo valuation model are considered highly complex and subjective.

For equity awards issued subsequent to the Reorganization, we utilize the trading price of our shares. Equity compensation is recognized over the requisite service period. For employees directly involved in exploration and development activities, equity compensation is capitalized to our oil and natural gas properties. Equity compensation not capitalized is recognized in general and administrative expenses or production expense in the consolidated statements of operations.

Income Taxes

Roan LLC was organized as a Delaware limited liability company and treated as a flow-through entity for income tax purposes. As a result, Roan LLC has historically passed through its taxable income to its owners for U.S. federal, state and local income tax purposes and, thus, was not subject to U.S. federal, state or local income taxes. Accordingly, no tax provision was made in the financial statements of Roan LLC since the income tax was an obligation of its members.

Following the Reorganization, Roan Inc. is a corporation, and, as a result, is subject to U.S. federal, state, and local income taxes. Deferred income taxes are recorded for temporary differences between the financial statement and income tax basis of assets and liabilities. Deferred tax assets are recognized for temporary differences that will be deductible in future years’ tax returns and for operating loss and tax credit carryforwards. Deferred tax assets are reduced by a valuation allowance if it is deemed more likely than not that some or all of the deferred tax assets will not be realized. Deferred tax liabilities are recognized for temporary differences that will be taxable in future years’ tax returns.

Recently Issued Accounting Standards Not Yet Adopted

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842) (“ASU 2016-02”). This update applies to any entity that enters into a lease, with some specified scope exemptions. Under this update, a lessee should recognize in the statement of financial position a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. While there were no major changes to the lessor accounting, changes were made to align key aspects with the revenue recognition guidance. This update will be effective for fiscal years beginning after December 15, 2018, including interim reporting periods within those fiscal years, with early application permitted. We enter into lease agreements to support our operations, such as office space, drilling rigs and field equipment. ASU 2016-02 will not impact the accounting or financial presentation of our mineral leases.

We plan to adopt the new standard using the simplified transition method described in ASU 2018-11 Leases (Topic 842): Targeted Improvements, and therefore will apply the new standard as of January 1, 2019. Accordingly, comparative information will not be adjusted and will continue to be reported under the previous lease standard. We plan to elect the package of practical expedients within ASU 2016-02 that allows an entity to not reassess prior to the effective date (i) whether any expired or existing contracts are or contain leases, (ii) the lease classification for any expired or existing leases or (iii) initial direct costs for any existing leases, but we do not plan to elect the practical expedient of hindsight when determining the lease term of existing contracts at the effective date. We also plan to elect the practical expedient under ASU 2018-01 Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842 that allows us to not evaluate existing or expired land easements not previously accounted for as leases prior to the effective date. We are working to complete our evaluation of the impact of ASU 2016-02 on our financial statements, accounting policies, and internal controls, including implementation of systems and processes to capture, classify and account for leases within the scope of the new guidance and to provide the related disclosures. At this time, the impact upon adoption of ASU 2016-02 and other related ASUs is expected to result in recognition of additional operating liabilities ranging from $7 million to $12 million, with corresponding right-of-use assets of the same amount based on the present value of the remaining minimum rental payments under current leasing standards for existing operating leases.

The new standard also provides practical expedients for an entity’s ongoing accounting. We currently plan to elect the short-term lease recognition exemption for all leases that qualify and the practical expedient to not separate lease and non-lease components for the majority of classes of underlying assets.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2018, 2017 or 2016. Although the impact of inflation has been insignificant in recent years, it is still a factor in the U.S. economy and we tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and natural gas prices increase drilling activity in our areas of operations.

Off-Balance Sheet Arrangements

We enter into certain off-balance sheet arrangements and transactions, including operating lease arrangements and undrawn letters of credit. We do not have any outstanding letters of credit. In addition, we enter into other contractual agreements in the normal course of business for processing and transportation as well as for other oil and natural gas activities. Other than the items discussed above, there are no other

arrangements, transactions or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or capital resource positions.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to a number of market risks including commodity price risk, credit risk and interest rate risk. The following information provides quantitative and qualitative information about our potential risks and how we seek to manage such risks.

Commodity Price Risk

The following table reflects our open commodity contracts as of December 31, 2018:

	2019	2020	Total
Oil fixed prices swaps			
Volume (Bbl)	5,405,670	1,599,500	7,005,170
Weighted-average price	$ 60.05	$ 63.14	$ 60.76
Natural gas fixed price swaps			
Volume (MMBtu)	43,800,000	12,325,000	56,125,000
Weighted-average price	$ 2.90	$ 2.63	$ 2.84
Natural gas basis swaps			
Volume (MMBtu)	29,200,000	3,640,000	32,840,000
Weighted-average price	$ 0.60	$ 0.62	$ 0.60
Natural gas liquids fixed price swaps			
Volume (Bbl)	1,095,000	—	1,095,000
Weighted-average price	$ 32.25	$ —	$ 32.25

Our primary market risk exposure is in the price we receive for our oil, natural gas and NGL production. Pricing for oil, natural gas and NGL production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. 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. Our hedging instruments allow us to reduce, but not eliminate, the potential effects of the variability in cash flow from operations due to fluctuations in oil and natural gas prices and provide increased certainty of cash flows. These derivatives are not designated as a hedging instrument for hedge accounting under GAAP and as such, gains or losses resulting from the change in fair value along with the gains or losses resulting from settlement of derivative contracts are reflected as gain or loss on derivative contracts included in the consolidated statement of operations.

There are a variety of hedging strategies and instruments used to hedge future price risk. We utilize fixed price swaps and basis swaps to manage the price risk associated with forecasted sale of our oil and natural gas production. Fixed price swaps are settled monthly based on differences between the fixed price specified in the contract and the referenced settlement price. Basis swaps are settled monthly based on differences between a fixed price differential and the applicable market price differential. When the referenced settlement price is less than the price specified in the contract, we receive an amount from the counterparty based on the price difference multiplied by the volume. When the referenced settlement price exceeds the price specified in the contract, we pay the counterparty an amount based on the price difference multiplied by the volume.

At December 31, 2018, we had a net asset position of $101.8 million related to our derivative contracts. Utilizing actual derivative contractual volumes under our fixed price swaps as of December 31, 2018, an increase of 10% in the forward curves associated with the underlying commodity would have decreased the net asset position to $55.9 million, while a decrease of 10% in the forward curves associated with the underlying commodity would have increased the net asset position to $159.7 million.

Credit Risk

Our principal exposure to credit risk is through the sale of our oil, natural gas and NGL production, which we market to energy marketing companies and refineries, and to a lesser extent, our derivative counterparties.
We are subject to credit risk resulting from the concentration of oil, natural gas and NGL receivables with two significant purchasers. We do not believe the loss of any single purchaser would materially impact our results of operations because oil, natural gas and NGLs are fungible products with well-established markets and numerous purchasers.

Our derivative transactions have been carried out in the over-the-counter market. The entry into derivative transactions in the over-the-counter market involves the risk that the counterparties, which are financial institutions, may be unable to meet the financial terms of the transactions. We monitor on an ongoing basis the credit ratings of our derivative counterparties and consider their credit default risk ratings in determining the fair value of our derivative contracts. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. The counterparties to our derivative contracts at December 31, 2018, are also lenders under our credit facility. As a result, we do not require collateral or other security from counterparties nor are we required to post collateral to support derivative instruments. We have master netting agreements with all of our derivative counterparties, which allow us to net our derivative assets and liabilities with the same counterparty. As a result of the netting provisions, our maximum amount of loss under derivative transactions due to credit risk is limited to the net amounts due from the counterparties under the derivative contracts.

Interest Rate Risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our credit facility. The terms of our credit facility provide for interest on borrowings at LIBOR or the ABR, in each case adjusted upward by an applicable margin based on the utilization percentage of the credit facility.

As of December 31, 2018, we had $514.6 million in outstanding borrowings under our credit facility with a weighted average interest rate on these borrowings of 5.21%. An increase or decrease of 1% in the interest rate would have a corresponding increase or decrease in our interest expense of approximately $5.1 million based on outstanding borrowings of $514.6 million under our credit facility as of December 31, 2018.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this item appears beginning on page F-1 of this report.

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.

As required by Rules 13a-15 and 15d-15 of the Exchange Act, 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 the end of the period covered by this Annual Report. 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 recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and that such information 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. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were not effective as of December 31, 2018 because of the material weaknesses in our internal control over financial reporting described below.

Changes in Internal Control over Financial Reporting.

Except as described below in Remediation Plan for the Material Weaknesses, there were no changes in our internal control over financial reporting during the quarter ended December 31, 2018, which materially affected, or were reasonably likely to materially affect, our internal control over financial reporting.

Management’s Report on Internal Control Over Financial Reporting

Management 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. Internal control over financial reporting is a process designed by, or under the supervision of, the Company’s principal executive officer and principal financial officer, or persons performing similar functions, and effected by the Company’s Board of Directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company’s financial statements for external purposes in accordance with generally accepted accounting principles.

Management assessed the effectiveness of the Company’s internal control over financial reporting as of December 31, 2018. In making this assessment, management used the criteria established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

A material weakness is a deficiency or a combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

We have identified the following material weaknesses in our internal control over financial reporting.

We had an overall lack of qualified personnel within the organization who possessed an appropriate level of expertise, experience and training to effectively design, implement and maintain:

(i) Adequate controls to monitor and assess the control environment. Specifically, internal controls were not designed or operating effectively to ensure appropriate monitoring or assessment of the control environment, including utilizing an appropriate control framework.
(ii) Adequate controls to establish appropriate entity level controls. Specifically, internal controls were not designed or operating effectively to ensure a sufficient amount of entity level controls were in place and operating effectively.
(iii) Effective controls over our period-end financial reporting processes, including controls over the preparation, analysis and review of certain significant account reconciliations required to assess the appropriateness of account balances at period-end; and controls over segregation of duties and the review of manual journal entries. Specifically, we did not design and maintain effective controls to verify that journal entries were properly prepared with sufficient supporting documentation or were reviewed and approved to ensure the accuracy and completeness of the manual journal entries. Additionally, certain key accounting personnel have the ability to prepare and post journal entries, as well as review account reconciliations, without an independent review by someone other than the preparer.
(iv) Effective controls over information technology systems that are relevant to the preparation of the financial statements. Specifically, we did not design and maintain (a) user access controls to ensure appropriate segregation of duties and to adequately restrict user and privileged access to infrastructure, financial applications, programs, and data to appropriate personnel, (b) program change management controls to ensure that information technology program and data changes affecting financial IT applications and underlying accounting records are identified, tested, authorized and implemented appropriately, (c) computer operation controls to ensure all financially significant batch jobs are monitored for the completeness and accuracy of data transfer, and (d) program development controls to ensure that new software development is aligned with business and IT requirements. The deficiencies described in this clause (iv), when aggregated, could impact both maintaining effective segregation of duties and the effectiveness of IT-dependent controls (such as automated controls that address the risk of material misstatement to one or more assertions, along with the IT controls and underlying data that support the effectiveness of system-generated data and reports) that could result in misstatements potentially impacting all financial statement accounts and disclosures that would not be prevented or detected in a timely manner.
(v) Effective controls over our reservoir engineering process for estimating proved oil, natural gas and NGL reserves, which are used in the calculation of depletion of the Company’s oil and natural gas properties. Specifically, we did not maintain effective controls to verify that the Company’s ownership interests in its oil and natural gas properties used in the reservoir engineering process are sufficiently reviewed to ensure completeness and accuracy of the information.
(vi) A sufficient complement of resources with an appropriate level of accounting knowledge, experience and training to develop and maintain an effective internal control environment.

These material weaknesses did not result in any material misstatements of our financial statements or disclosures. The material weaknesses could, however, result in a misstatement of relevant account balances or disclosures that would result in a material misstatement to the annual or interim financial statements that would not be prevented or detected.

Because of these material weaknesses, management has concluded that the Company’s internal control over financial reporting was not effective as of December 31, 2018.

This Annual Report does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting. Management’s report was not subject to attestation by the Company’s registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit the Company to provide only management’s report in this Annual Report.

Remediation Plan for the Material Weaknesses

We have taken and will continue to take a number of actions to remediate these material weaknesses. We are currently implementing measures designed to improve our internal control over financial reporting and remediate the control deficiencies that led to the material weaknesses, including but not limited to, (i) hiring additional IT and accounting personnel with appropriate technical skillsets, (ii) initiating design and implementation of our control environment, including the expansion of formal accounting and IT policies and procedures and financial reporting controls, (iii) conducting a company-wide assessment of our control environment, (iv) implementing appropriate review and oversight responsibilities within the accounting and financial reporting functions, and (v) evaluating controls over our information technology environment. We can give no assurance that these actions will remediate these material weaknesses in internal controls or that additional material weaknesses in our internal control over financial reporting will not be identified in the future.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information as to Item 10 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2018.

ITEM 11. EXECUTIVE COMPENSATION

Information as to Item 11 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2018.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information as to Item 12 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2018.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information as to Item 13 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2018.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information as to Item 14 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2018.

PART IV
ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

The following documents are filed as a part of this report:

(1) Consolidated Financial Statements

Reference is made to the Index to Consolidated Financial Statements appearing on page F-1.

(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 or notes thereto.

(3) Exhibits

Exhibit No.	Description
2.1	Linn Merger Agreement, dated September 24, 2018, by and among Linn Energy, Inc., Roan Resources, Inc. and Linn Merger Sub #2, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed on September 24, 2018)
2.2	Roan Merger Agreement, dated September 24, 2018, by and among Roan Holdings, LLC, Roan Holdings Holdco, LLC, Roan Resources, Inc. and Linn Merger Sub #3, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed on September 24, 2018)
2.3	Master Reorganization Agreement, dated September 17, 2018, by and among Linn Energy, Inc., Roan Holdings, LLC, and Roan Resources LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed by Linn Energy, Inc. on September 21, 2018)
2.4	Separation and Distribution Agreement, dated August 7, 2018, by and between Linn Energy, Inc. and Riviera Resources, Inc. (incorporated by reference to Exhibit 2.1 to Form 8-K filed by Linn Energy, Inc. on August 10, 2018)
2.5	Agreement and Plan of Merger, dated July 25, 2018, by and among Linn Energy Inc., New LINN Inc. and Linn Merger Sub #1, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed by Linn Energy, Inc. on July 26, 2018)
3.1	Second Amended and Restated Certificate of Incorporation of Roan Resources, Inc. (incorporated by reference to Exhibit 3.1 to Form 8-K filed on September 27, 2018)
3.2	Second Amended and Restated Bylaws of Roan Resources, Inc. (incorporated by reference to Exhibit 3.2 to Form 8-K filed on September 27, 2018)
4.1	Registration Rights Agreement, dated September 24, 2018, by and among Roan Resources, Inc. and each of the other parties listed on the signature page thereto (incorporated by reference to Exhibit 4.1 to Form 8-K filed on September 24, 2018)
4.2	Stockholders Agreement, dated September 24, 2018, by and among Roan Resources, Inc., the Existing LINN Owners (as defined therein), Roan Holdings, LLC and any other persons signatory thereto from time to time (incorporated by reference to Exhibit 4.2 to Form 8-K filed on September 24, 2018)
10.1	Credit Agreement, dated September 5, 2017, by and among Citibank, N.A., as administrative agent for the Lenders (incorporated by reference to Exhibit 10.1 to Form 8-K filed on September 24, 2018)
10.2	Amendment No. 1 to Credit Agreement, dated April 9, 2018 (incorporated by reference to Exhibit 10.2 to Form 8-K filed on September 24, 2018)
10.3	Amendment No. 2 to Credit Agreement, dated May 30, 2018 (incorporated by reference to Exhibit 10.3 to Form 8-K filed on September 24, 2018)

10.4	Amendment No. 3 to Credit Agreement, dated September 27, 2018 (incorporated by reference to Exhibit 10.1 to Form 8-K filed on September 27, 2018)
10.5†	Roan Resources, Inc. Amended and Restated Management Incentive Plan, dated September 24, 2018 (incorporated by reference to Exhibit 10.4 to Form 8-K filed on September 24, 2018

10.6†	Form of Performance Share Unit Grant Notice and Performance Share Unit Award Agreement pursuant to the Roan Resources, Inc. Amended and Restated Management Incentive Plan (incorporated by reference to Exhibit 10.5 to Form 8-K filed on September 24, 2018)
10.7	Voting Agreement, dated September 24, 2018, by and among Roan Resources, Inc., the Existing LINN Owners (as defined therein), Roan Holdings, LLC and any other persons signatory thereto from time to time (incorporated by reference to Exhibit 10.6 to Form 8-K filed on September 24, 2018)
10.8	Second Amended and Restated Limited Liability Company Agreement of Roan Resources LLC (incorporated by reference to Exhibit 10.7 to Form 8-K filed on September 24, 2018)
10.9†	Amended and Restated Employment Agreement, dated November 6, 2017, between Roan Resources, Inc. and Tony Maranto (incorporated by reference to Exhibit 10.8 to Form 8-K filed on September 24, 2018)
10.10†	Employment Agreement, dated June 18, 2018, between Roan Resources LLC and David Edwards (incorporated by reference to Exhibit 10.9 to Form 8-K filed on September 24, 2018)
10.11†	Employment Agreement, dated November 6, 2017, between Roan Resources LLC and Joel Pettit (incorporated by reference to Exhibit 10.10 to Form 8-K filed on September 24, 2018)
10.12†	Employment Agreement, dated November 6, 2017, between Roan Resources LLC and Greg Condray (incorporated by reference to Exhibit 10.11 to Form 8-K filed on September 24, 2018)
10.13†	Employment Agreement, dated September 17, 2018, between Roan Resources LLC and David Treadwell (incorporated by reference to Exhibit 10.12 to Form 8-K filed on September 24, 2018)
10.14	Indemnification Agreement, dated September 24, 2018, between Roan Resources, Inc. and Tony Maranto (incorporated by reference to Exhibit 10.13 to Form 8-K filed on September 24, 2018)
10.15	Indemnification Agreement, dated September 24, 2018, between Roan Resources, Inc. and Matthew Bonanno (incorporated by reference to Exhibit 10.14 to Form 8-K filed on September 24, 2018)
10.16	Indemnification Agreement, dated September 24, 2018, between Roan Resources, Inc. and Evan Lederman (incorporated by reference to Exhibit 10.15 to Form 8-K filed on September 24, 2018)
10.17	Indemnification Agreement, dated September 24, 2018, between Roan Resources, Inc. and John Lovoi (incorporated by reference to Exhibit 10.16 to Form 8-K filed on September 24, 2018)
10.18	Indemnification Agreement, dated September 24, 2018, between Roan Resources, Inc. and Paul B. Loyd Jr. (incorporated by reference to Exhibit 10.17 to Form 8-K filed on September 24, 2018)
10.19	Indemnification Agreement, dated September 24, 2018, between Roan Resources, Inc. and Michael Raleigh (incorporated by reference to Exhibit 10.18 to Form 8-K filed on September 24, 2018)
10.20	Indemnification Agreement, dated September 24, 2018, between Roan Resources, Inc. and Andrew Taylor (incorporated by reference to Exhibit 10.19 to Form 8-K filed on September 24, 2018)
10.21	Indemnification Agreement, dated September 24, 2018, between Roan Resources, Inc. and Anthony Tripodo (incorporated by reference to Exhibit 10.20 to Form 8-K filed on September 24, 2018)
10.22	Tax Matters Agreement, dated August 7, 2018, by and among Linn Energy, Inc., Riviera Resources, Inc. and the Riviera Resources, Inc. Subsidiaries (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Linn Energy, Inc. on August 10, 2018)
10.23	Transition Services Agreement, dated August 7, 2018, by and between Linn Energy, Inc. and Riviera Resources, Inc. (incorporated by reference to Exhibit 10.2 to Form 8-K filed by Linn Energy, Inc. on August 10, 2018)
10.24	Indemnification Agreement, dated November 5, 2018, between Roan Resources, Inc. and Joseph Mills (incorporated by reference to Exhibit 10.1 to Form 8-K filed on November 6, 2018)
10.25†*	Form of Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement pursuant to the Roan Resources, Inc. Amended and Restated Management Incentive Plan
10.26	Amendment No. 4 to Credit Agreement, dated March 13, 2019 (incorporated by reference to Exhibit 10.1 to Form 8-K filed on March 13, 2019)
21.1*	List of Subsidiaries of Roan Resources, Inc.
23.1*	Consent of PricewaterhouseCoopers LLP
23.2*	Consent of DeGolyer and MacNaughton

31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Report of DeGolyer and MacNaughton

101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

*Filed herewith
† Compensatory plan or arrangement

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 and 15(d) the Securities Exchange Act of 1934, the registrant has duly caused this Annual Report to be signed on its behalf by the undersigned, thereunto duly authorized.

	ROAN RESOURCES, INC.
Date:	April 1, 2019
By:	/s/ Tony C. Maranto
Name:	Tony C. Maranto
Title:	Chairman, Chief Executive Officer and President