ROAN RESOURCES, INC.
Form S-1/A
April 18, 2019
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As filed with the Securities and Exchange Commission on April 18, 2019

Registration No. 333-227953

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Amendment No. 2

to

Form S-1

REGISTRATION STATEMENT

UNDER

THE SECURITIES ACT OF 1933

Roan Resources, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**1311**	**83-1984112**
(State or other jurisdiction of incorporation or organization)	**(Primary Standard Industrial Classification Code Number)**	**(IRS Employer Identification Number)**

14701 Hertz Quail Springs Pkwy

Oklahoma City, OK 73134

(405) 241-2150

(Address, including zip code, and telephone number, including area code, of registrant s principal executive offices)

David Edwards

Chief Financial Officer

14701 Hertz Quail Springs Pkwy

Oklahoma City, OK 73134

(405) 896-8050

(Name, address, including zip code, and telephone number, including area code, of agent for service)

Copies to:

Alan Beck

James R. Brown

Vinson & Elkins L.L.P.

1001 Fannin Street, Suite 2500

Houston, Texas 77002

(713) 758-2222

Approximate date of commencement of proposed sale of the securities to the public: As soon as practicable after the effective date of this Registration Statement.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box:

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering.

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering.

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering.

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

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 7(a)(2)(B) of the Securities Act.

The registrant hereby amends this Registration Statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment that specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933, as amended, or until this Registration Statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

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The information in this prospectus is not complete and may be changed. The Selling stockholders may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities and it is not soliciting an offer to buy these securities in any state where the offer or sale is not permitted.

SUBJECT TO COMPLETION, DATED APRIL 18, 2019

117,176,843 Shares

Roan Resources, Inc.

Class A Common stock

The selling stockholders named in this prospectus may offer 117,176,843 shares of our Class A common stock, par value $0.001 per share (Class A common stock), which the selling stockholders acquired in the reorganization described under Reorganization. The selling stockholders will receive all proceeds, and we will not receive any proceeds from the sale of the shares of Class A common stock being offered in this prospectus. We will bear all costs, expenses, and fees in connection with the registration of the shares of Class A common stock. The selling stockholders will bear all commissions and discounts, if any, attributable to their sale of shares of Class A common stock.

Our Class A common stock trades on the New York Stock Exchange (the NYSE) under the symbol ROAN. The last reported sales price of our Class A common stock on April 17, 2019 was $4.12 per share. You are urged to obtain current market quotations for our Class A common stock.

The selling stockholders may sell the shares of Class A common stock being offered by them from time to time on the NYSE, in market transactions, in negotiated transactions or otherwise, and at prices and terms that will be determined by the then prevailing market price for the shares of Class A common stock or at negotiated prices directly or through a broker or brokers, who may act as agent or as principal or by a combination of such methods of sale. For additional information regarding the methods of sale, you should refer to the section entitled Plan of Distribution beginning on page 141 of this prospectus.

Because all of the shares of Class A common stock offered under this prospectus are being offered by the selling stockholders, we cannot currently determine the price or prices at which our shares may be sold under this prospectus.

We may amend or supplement this prospectus from time to time by filing amendments or supplements as required. You should read this entire prospectus and any amendments carefully before you make your investment decision.

Investing in our Class A common stock involves risks. See **Risk Factors on page 18.**

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The date of this prospectus is , 2019.

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This prospectus is part of a shelf registration statement that we have filed with the SEC using a shelf registration process. Under this shelf registration process, the selling stockholders may, from time to time, offer and sell the shares described in this prospectus in one or more offerings.

This prospectus provides you with a general description of the shares the selling stockholders may offer. Each time the selling stockholders sell our shares using this prospectus, to the extent necessary, we may provide a prospectus supplement that will contain specific information about the terms of that offering, including the number of shares being offered, the manner of distribution, the identity of any underwriters or other counterparties and other specific terms related to the offering. The prospectus supplement may also add, update or change information contained in this prospectus. To the extent that any statement made in an accompanying prospectus supplement is inconsistent with statements made in this prospectus, the statements made in this prospectus will be deemed modified or superseded by those made in the accompanying prospectus supplement. You should read both this prospectus and any prospectus supplement together.

You should rely only on the information contained in this prospectus, as may be amended and supplemented from time to time, and any free writing prospectus prepared by us or on behalf of us or the information to which we have referred you. Neither we nor the selling stockholders have authorized anyone to provide you

with information different from that contained in this prospectus, as may be amended and supplemented from time to time, and any free writing prospectus. We take no responsibility for, and can provide no assurance as to the reliability of, any other information that others may give you. The selling stockholders are offering to sell shares of Class A common stock and seeking offers to buy shares of Class A common stock only in jurisdictions where offers and sales are permitted.

This prospectus contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. See Risk Factors and Cautionary Statement Regarding Forward-Looking Statements.

Industry and Market Data

The market data and certain other statistical information used throughout this prospectus are based on independent industry publications, government publications and other published independent sources. Although we believe these third-party sources are reliable as of their respective dates, neither we, nor the selling stockholders have independently verified the accuracy or completeness of this information. Some data is also based on our good faith estimates. The industry in which we operate is subject to a high degree of uncertainty and risk due to a variety of factors, including those described in the section entitled Risk Factors. These and other factors could cause results to differ materially from those expressed in these publications.

Trademarks and Trade Names

We own or have rights to various trademarks, service marks and trade names that we use in connection with the operation of our business. This prospectus may also contain trademarks, service marks and trade names of third parties, which are the property of their respective owners. Our use or display of third parties trademarks, service marks, trade names or products in this prospectus is not intended to, and does not imply, a relationship with us or an endorsement or sponsorship by or of us. Solely for convenience, the trademarks, service marks and trade names referred to in this prospectus may appear without the ®, TM or SM symbols, but such references are not intended to indicate, in any way, that we will not assert, to the fullest extent under applicable law, our rights or the right of the applicable licensor to these trademarks, service marks and trade names.

Basis of Presentation

Unless otherwise indicated or the context otherwise requires, references herein to

- Roan, we, our, us, the Company and our company refer (i) prior to the consummation of our reorga described under Reorganization, to Roan LLC and (ii) after the consummation of such reorganization, to Roan Inc. and its consolidated subsidiaries;

- Roan Inc. refer to Roan Resources, Inc.;

- Roan LLC refer to Roan Resources LLC, our predecessor;

- Reorganization refer to the transactions contemplated by the Merger Agreements and the Master Reorganization Agreement, as described in Reorganization ;

- Old Linn refer to Linn Energy, Inc. prior to the Riviera Separation and described in Reorganization ;

- New Linn refer to New LINN Inc. (subsequently renamed Linn Energy, Inc.);

Roan Holdings refer to Roan Holdings, LLC;

Roan Holdco refer to Roan Holdings Holdco, LLC, a wholly owned subsidiary of Roan Holdings;

Riviera refer to Riviera Resources, Inc.;

Riviera Separation refer 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 ;

Legacy Linn Stockholders refer to the stockholders of New Linn;

Effective Date refer to September 24, 2018, the closing date of the Reorganization;

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- Merge refer to the play located in the Canadian, Grady and McClain counties in the Anadarko Basin of Oklahoma;

- SCOOP refer to the South Central Oklahoma Oil Province play principally located in the Anadarko Basin area of Oklahoma; and

- STACK refer to the Sooner Trend, Anadarko (Basin), Canadian and Kingfisher play located in the Anadarko Basin area of Oklahoma.

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 prospectus (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 prospectus, (i) prior to August 31, 2017, the date of the completion of the Contribution (as defined herein) described under Recent Developments History and Reorganization and Reorganization, is that of Citizen Energy II, LLC (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 gas assets contributed to Roan LLC by subsidiaries of Linn Energy, Inc. (the Linn Contributed Business).

The financial data and certain other data presented in this prospectus have been rounded to the nearest whole number or the nearest decimal. Therefore, the sum of the numbers in a column may not conform exactly to the total figure given for that column in certain tables in this prospectus. In addition, certain percentages presented in this prospectus reflect calculations based upon the underlying information prior to rounding and, accordingly, may not conform exactly to the percentages that would be derived if the relevant calculations were based upon the rounded numbers or may not sum due to rounding.

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PROSPECTUS SUMMARY

This summary highlights information contained elsewhere in this prospectus. You should read the entire prospectus carefully, including the information under the headings Risk Factors, Cautionary Statement Regarding Forward-Looking Statements and Management s Discussion and Analysis of Financial Condition and Results of Operations and the financial statements and the notes to those financial statements appearing elsewhere in this prospectus. You should read Risk Factors for more information about important risks that you should consider carefully before investing in our Class A common stock. Certain oil and gas industry terms used in this prospectus are defined in the Glossary of Oil and Natural Gas Terms in Annex A of this prospectus.

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 prospectus (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 prospectus, (i) prior to August 31, 2017, the date of the completion of the Contribution described under Recent Developments History and Reorganization and Reorganization, 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 the Linn Contributed Business.

Our Company

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. Our objective is to maximize shareholder value and corporate returns by generating steady production growth, strong pre-tax margins and significant cash flow.

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. As of 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).

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We have chosen to focus our development efforts on the Merge play, as we believe it benefits from the following attributes:

Stacked Formations. The Merge has been proven to be prospective for two primary resource formations: the Mayes (Meramec/Sycamore equivalent) formation and the Woodford formation. We and our predecessors have demonstrated successful economic development of both benches, with 63 gross (53 net) and 80 gross (65 net) horizontal operated wells producing from the Mayes and Woodford formations, respectively.

Reservoir Quality. Reservoir characteristics from petrophysical analysis demonstrate high porosity and permeability development in the Merge as compared to other unconventional plays.

Phase Window Positioning. The thermal maturity of the source rock throughout the eastern portion of the Merge results in production profiles characterized by high percentages of oil and NGLs. Specifically, over 80% of our operated acreage is within areas we believe demonstrate higher percentage production of oil and NGLs within the Merge play.

Pressure Gradients. Geopressure across our operated acreage position in the Merge play ranges from slightly to significantly overpressured at approximately 0.45 to 0.65 pounds per square inch (psi) per foot of true vertical depth, resulting in superior well deliverability and improved GOR trend stability as compared to normal to under-pressured reservoirs.

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 held-by-production (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.

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The table below provides a summary of our acreage position as of December 31, 2018:

	Total
Operated Sections	313
Operated Acres	122,254
Non-Operated Acres	49,717
Total Acres	171,970
% HBP	84%
% Operated	71%

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 (EURs) 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.

Reserves Information

The following table provides summary information regarding our proved reserves as of December 31, 2018, based on a reserve report prepared by DeGolyer and MacNaughton, our independent reserve engineers (DeGolyer and MacNaughton).

Estimated Total Proved Reserves							
Oil (MMBbls)	**NGLs (MMBbls)**	**Natural Gas (Bcf)**	**Total (MMBoe)**	**PV-10 ($)(1)(2)**	**% Oil**	**% Liquids**	**% Developed**
55.7	98.4	911.2	306.0	2,091,509	18.2	50.4	39.3

(1) Presented in thousands. 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. Please see Risk Factors The standardized measure of our estimated reserves contained in this prospectus and in the footnotes to our financial statements is not an accurate estimate of the current fair value of our estimated reserves. 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. Please see Summary Historical and Unaudited Pro Forma Financial Data Non-GAAP Financial Measure PV-10 .

(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.

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. We consider our extensive inventory of high-potential, oil and liquids-weighted drilling locations to be relatively low-risk based on information gathered from over 400 horizontal wells developed since early 2014, of which 152 were drilled by us or our predecessors, and over 4,450 vertical wells developed in our development area, industry activity surrounding our acreage, subsurface data, including well cores and logs and 3-D seismic and the consistent geology surrounding our position.

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. Our management and technical teams intend to apply their operational expertise, data gained from our large acreage position in the Merge play and available third-party data to deploy advanced drilling, completion and production management technologies that maximize well productivity and control capital and operating costs. 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. Our highly experienced management and technical teams have a substantial track record of developing unconventional plays, which we believe is instrumental in our achievement of these operational and capital efficiencies.

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. We will adjust the size of our rig program to optimize our overall development program and with a view to limiting the lag time between the development of parent and child wells. Through these measures, we seek to target an optimal combination of net present value and rate of return associated with the development of a particular unit. According to RS Energy Group, child wells are generally at least 25% more productive if drilled within 1.5 years of the development of the parent well, as compared to child wells drilled 1.5 to 3 years following the development of the parent well. Operational and developmental control positions us to minimize the adverse impacts associated with this time lag.

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. Consistent with our disciplined approach to financial management, we have an active commodity hedging program that seeks to reduce our exposure to downside commodity price volatility, enabling us to protect future cash flows and maintain liquidity to fund our development program.

Selectively pursue opportunities to augment our asset base through the disciplined acquisition or leasing of oil and natural gas properties. 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. Operatorship of our position allows us the flexibility to control the pace of our development plan, as well as the lengths of our laterals and our drilling and well completion techniques.

Long-lived inventory of locations with predictable production profiles that provide high rate-of-return development opportunities. Through the drilling of over 163 operated horizontal wells and participation in over 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. While oil represents a significant portion of our total revenues, natural gas and NGLs comprise a majority of our reserves and production. While we believe we have favorable realized price differentials for natural gas and NGLs compared to other basins, our realized natural gas price differential is based on the sales price at multiple hubs and our NGLs are sold on a product by product basis. 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. Joel Pettit, our Executive Vice President Operations and Marketing, worked in EOG s Mid-Continent Division for over a decade. Greg Condray, our Executive Vice President Geosciences and Business Development, worked with Mr. Pettit in EOG s Mid-Continent Division as Division Exploration Manager, and had considerable experience at Chesapeake Energy leading initial delineation and development efforts in the Eagle Ford, Haynesville and Powder River Basin. 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 held by production 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.

Historical Capital Expenditures and Capital Budget

Our 2019 capital budget is approximately $520 million to $570 million. For the year ended December 31, 2018, our aggregate drilling and completion capital expenditures were approximately $705.2 million.

Because we are the operator of a high percentage of our acreage and a majority of our acreage is held by production, the amount and timing of our capital expenditures is 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, and prevailing and anticipated prices for oil and natural gas. A deferral of planned capital expenditures, particularly with respect to drilling and completing new wells, could result in a reduction in anticipated production and cash flows and loss of acreage through lease expirations.

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In addition, we may be required to reclassify some portion of our reserves currently booked as proved undeveloped reserves to no longer be proved reserves if such a deferral of planned capital expenditures means we will be unable to develop such reserves within five years of their initial booking.

Recent Developments

History and Reorganization

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 a contribution agreement pursuant to which, among other things, Old Linn and Citizen agreed to contribute certain oil and natural gas assets to Roan LLC (the Contribution), 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 (the Master Reorganization Agreement), to effectuate the reorganization of New Linn s and Roan Holdings respective 50% equity interests in Roan LLC under Roan Resources, 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.

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The following chart provides a simplified overview of our organizational structure after giving effect to the Reorganization.

On November 9, 2018, the Company s Class A common stock began trading on the NYSE under the symbol ROAN.

Credit Facility Amendment

On March 13, 2019, the Company amended its existing credit agreement, dated as of September 5, 2017 (as amended, amended and restated, supplemented or otherwise modified from time to time, our credit facility) to, among other things, (i) increase the borrowing base under the credit facility to $750 million, provided that there will be no reduction of the borrowing base in connection with the issuance of any Permitted Additional Debt (as defined in the credit facility) for the first (x) $400 million in principal of such unsecured Permitted Additional Debt and (y) $250 million in principal of such secured Permitted Additional Debt and (ii) permit certain additional restricted payments to be made. As of December 31, 2018, after giving effect to this amendment, our outstanding borrowings under the credit facility were $514.6 million with available borrowing capacity of $235.4 million and a cash balance of $6.9 million. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit Facility.

Risk Factors

Investing in our Class A common stock involves risks. You should carefully read and consider the section of this prospectus titled Risk Factors beginning on page 18 and all other information in this prospectus before investing in our Class A common stock.

Corporate Information

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.* We make our periodic reports and other information filed with or furnished to the Securities and Exchange Commission (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. Information on our website or any other website is not incorporated by reference into this prospectus and does not constitute a part of this prospectus.

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The Offering

Class A common stock offered by the selling stockholders	117,176,843 shares.
Class A common stock outstanding	152,539,532 shares.
Use of proceeds	We will not receive any proceeds from the sale of shares by the selling stockholders. Please see Use of Proceeds.
Dividend policy	We do not anticipate paying any cash dividends on our Class A common stock. In addition, our credit facility places certain restrictions on our ability to pay cash dividends. Please see Dividend Policy.
Listing and trading symbol	Our Class A common stock trades on the NYSE under the symbol ROAN.
Risk factors	You should carefully read and consider the information set forth under the heading Risk Factors and all other information set forth in this prospectus before deciding to invest in our Class A common stock.

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Summary Historical and Unaudited Pro Forma Financial Data

Roan Resources, 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 prospectus (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 prospectus, (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 Old Linn in connection with the Contribution.

The summary historical statement of operations data for the years ended December 31, 2018, 2017 and 2016 was derived from the audited historical financial statements of Roan Inc. included elsewhere in this prospectus. The summary historical balance sheet data as of December 31, 2018 and 2017 was derived from the audited historical financial statements of Roan Inc. included elsewhere in this prospectus.

Our historical results are not necessarily indicative of future results. You should read the following table in conjunction with Selected Historical and Unaudited Pro Forma Financial Data, Management s Discussion and Analysis of Financial Condition and Results of Operations and the historical and pro forma financial statements and accompanying notes included elsewhere in this prospectus.

The summary unaudited pro forma condensed statement of operations data for the year ended December 31, 2018 has been prepared to give pro forma effect to the Reorganization as if it had occurred on January 1, 2018. The summary unaudited pro forma condensed financial data is provided for illustrative purposes only and is not indicative of the results that actually would have occurred had the transactions been in effect on the dates or for the periods indicated, or of results that may occur in the future.

	Pro Forma Year Ended December 31, 2018 (Unaudited)	Year Ended December 31, 2018	2017(1)	2016
		(in thousands, except per share data)		
Statement of Operations Data:				
Revenues(2):				
Oil sales	$ 275,239	$ 275,239	$ 76,876	$ 30,565
Natural gas sales	46,966	46,966	46,303	16,093
Natural gas sales Affiliates	29,090	29,090	2,908	
Natural gas liquid sales	51,467	51,467	35,217	8,307
Natural gas liquid sales Affiliates	37,005	37,005	5,081	
Gain (loss) on derivative contracts	78,054	78,054	(6,797)	
Total revenues	517,821	517,821	159,588	54,965
Operating Expenses(2):				
Production expenses	47,600	47,600	16,872	5,090
Gathering, transportation and processing			18,602	5,920
Production taxes	17,579	17,579	3,685	1,087
Exploration expenses	43,303	43,303	32,629	5,258
Depreciation, depletion, amortization and accretion	123,922	123,922	37,376	24,996
General and administrative	56,297	60,874	31,357	5,581
Gain on sale of oil and natural gas properties			(838)	
Total operating expenses	288,701	293,278	139,683	47,932
Total operating income	229,120	224,543	19,905	7,033
Other income (expense):				
Interest expense, net	(8,352)	(8,352)	(1,461)	(86)
Other income			13	
Net income before income taxes	220,768	216,191	18,457	6,947
Income tax expense(3)	56,296	356,862		
Net income (loss)	$ 164,472	$ (140,671)	$ 18,457	$ 6,947
Earnings (loss) per share				
Basic	$ 1.08	$ (0.92)	$ 0.18	$ 0.11
Diluted	$ 1.08	$ (0.92)	$ 0.18	$ 0.11
Weighted average number of shares outstanding				
Basic	152,540	152,232	100,473	62,394
Diluted	152,540	152,232	100,473	62,394

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	Pro Forma Year Ended December 31, 2018 (Unaudited)	Year Ended December 31, 2018	2017(1)	2016
		(In thousands)		
Balance Sheet Data (at period end):				
Total assets		$ 2,749,109	$ 1,885,592	
Total liabilities		$ 1,254,075	$ 300,823	
Total equity		$ 1,495,034	$ 1,584,769	
Other Financial Data:				
Adjusted EBITDAX(4)	$ 299,342	$ 299,342	$ 97,549	$ 37,287
Net Debt(4)		$ 507,756	$ 83,868	$ 13,147

(1) On August 31, 2017, Old Linn contributed certain oil and natural gas assets to Roan LLC. The revenue and operating expenses associated with these assets for the period from contribution through December 31, 2017 is included in our results for the year ended December 31, 2017.

(2) Revenue and operating expenses for the year ended December 31, 2018 reflects 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.

(3) The pro forma data reflects pro forma tax expense based on the statutory tax rate of 25.5% at December 31, 2018 to prospective periods. As described under Reorganization, Roan Inc. was formed in conjunction with the Reorganization. Roan Inc. is taxable as a corporation under the Internal Revenue Code of 1986, as amended (the Code), 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 federal income tax purposes, were deemed to pass to the members. Accordingly, no tax provision was made in the historical financial statements of Roan LLC since the income tax was an obligation of the members. The pro forma data excludes the income tax expense associated with the initial deferred tax liability recognized as a result of the Reorganization. The initial recording of the deferred tax liability has been reflected in the historical financial statements, but is not included in the pro forma data due to its non-recurring nature.

(4) Adjusted EBITDAX and Net Debt are non-GAAP financial measures. For a definition of Adjusted EBITDAX and a reconciliation of Adjusted EBITDAX to net income (loss) and a reconciliation of Net Debt to long-term debt, please see Non-GAAP Financial Measure below.

Non-GAAP Financial Measure

Adjusted EBITDAX and Net Debt

Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management and other users of our financial statements. We define Adjusted EBITDAX as net income (loss) adjusted for interest expense, depreciation, depletion, amortization and accretion, income tax expense, exploration costs, non-cash equity-based compensation expense, gain on early termination of derivative contracts, non-cash (gain) loss on derivative contracts, reorganization transaction costs and expense for allowance for doubtful accounts. Adjusted EBITDAX is not a measure of net income as determined by GAAP. Our predecessor, Roan LLC, passed through its taxable income to its owners for other income tax purposes and thus, we have not incurred historical income tax expenses.

We believe Adjusted EBITDAX is useful because it allows our management to more effectively evaluate the operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We add the items listed above to net income (loss) in arriving at Adjusted

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EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company s financial performance, such as a company s cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDAX.

Net Debt is a non-GAAP financial measure equal to long-term debt outstanding less cash on hand as of the date presented. Our computations of Adjusted EBITDAX and Net Debt may not be comparable to other similarly titled measures of other companies or to such measure in our credit facility or any of our other contracts. The following tables presents a reconciliation of Adjusted EBITDAX to net income (loss), and a reconciliation of Net Debt to long-term debt, our most directly comparable financial measures calculated and presented in accordance with GAAP for each of the periods indicated.

	Pro Forma Year Ended December 31, 2018	Year Ended December 31, 2018	2017	2016
		(in thousands)		
Adjusted EBITDAX reconciliation to net income (loss):				
Net income (loss)	$ 164,472	$ (140,671)	$ 18,457	$ 6,947
Interest expense	8,352	8,352	1,461	86
Income tax expense	56,296	356,862		
Exploration expense	43,303	43,303	32,629	5,258
Non-cash equity-based compensation expense	11,030	11,030	379	
Depletion, depreciation, amortization and accretion	123,922	123,922	37,376	24,996
Non-cash (gain) loss on derivatives contracts	(111,333)	(111,333)	9,502	
Gain on early termination of derivative contracts			(2,255)	
Reorganization transaction costs		4,577		
Allowance for doubtful accounts	3,300	3,300		
Adjusted EBITDAX	$ 299,342	$ 299,342	$ 97,549	$ 37,287

	As of December 31, 2018	2017
	(in thousands)	
Net debt reconciliation to long-term debt:		
Long-term debt	$ 514,639	$ 85,339
Cash	6,883	1,471
Net Debt	$ 507,756	$ 83,868

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PV-10

PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows. Calculation of PV-10 does not give effect to derivatives transactions. Management believes that PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, management believes the use of a pre-tax measure is valuable for evaluating the Company. PV-10 should not be considered as an alternative to the standardized measure of discounted future net cash flows as computed under GAAP.

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Summary Historical Reserve and Operating Data

The following table presents, as of December 31, 2018, summary data with respect to our estimated net proved reserves.

The reserve estimates attributable to our properties as of December 31, 2018 are based on a reserve report prepared by DeGolyer and MacNaughton, using SEC pricing. Please see Management s Discussion and Analysis of Financial Condition and Results of Operations and Business Oil and Natural Gas Data Proved Reserves in evaluating the material presented below.

		As of December 31, 2018 (1)
Proved developed reserves:		
Oil (MBbls)		18,652
Natural gas (MMcf)		369,677
NGLs (MBbls)		39,927
Total (MBoe)(2)		120,192
Proved undeveloped reserves:		
Oil (MBbls)		37,031
Natural gas (MMcf)		541,505
NGLs (MBbls)		58,485
Total (MBoe)(2)		185,767
Total proved reserves:		
Oil (MBbls)		55,683
Natural gas (MMcf)		911,182
NGLs (MBbls)		98,412
Total (MBoe)(2)		305,959
Benchmark Oil and Natural Gas Prices(1):		
Oil WTI per Bbl	$	65.66
Natural gas Henry Hub per MMBtu	$	3.16
Standardized measure (in thousands)	$	1,699,701
PV-10 of proved reserves (in thousands)(3)	$	2,091,509

(1) 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.

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

(3) 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. Please see Summary Historical and Unaudited Pro Forma Financial Data Non-GAAP Financial Measure PV-10.

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

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:

	Year Ended December 31, 2018		Year Ended December 31, 2017	
Production data:				
Oil (MBbls)		4,364		1,454
Natural gas (MMcf)		41,890		17,582
NGLs (MBbls)		4,592		1,524
Total (MBoe)(1)		15,938		5,908
Average daily production (MBoe/d)		43.7		16.2
Average prices(2):				
Oil (per Bbl)	$	63.07	$	52.87
Natural gas (per Mcf)	$	1.82	$	2.80
NGLs (per Bbl)	$	19.27	$	26.44
Total (per Boe)	$	27.59	$	28.16
Average realized prices after effects of derivative settlements(2)(3):				
Oil (per Bbl)	$	55.87	$	53.57
Natural gas (per Mcf)	$	1.73	$	2.89
NGLs (per Bbl)	$	19.60	$	26.44
Total (per Boe)	$	25.50	$	28.60
Average costs (per MBoe)(2):				
Production expenses	$	2.99	$	2.86
Gathering, transportation and processing expenses	$		$	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	$	3.82	$	5.31
Gain on sale of oil and natural gas properties	$		$	(0.14)

Total	$	18.41	$	23.65

(1) May not sum or recalculate due to rounding.
(2) Average prices and costs 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,

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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.

(3) Excludes settlements of commodity derivative contracts prior to their contractual maturity.

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RISK FACTORS

Investing in our Class A common stock involves risks. You should carefully consider the information in this prospectus, including the matters addressed under Cautionary Statement Regarding Forward-Looking Statements, and the following risks before making an investment decision. If any of the following risks actually occur, the trading price of our Class A common stock could decline and you may lose all or part of your investment. Additional risks not presently known to us or that we currently deem immaterial could also materially affect our business.

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 New York Mercantile Exchange (NYMEX) prices were $27.45 per Bbl and $1.64 per MMBtu, respectively. Although average oil and 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 $55.80 per Bbl and $2.66 per MMBtu during March 2019. Likewise, NGLs, which are made up of ethane, propane, isobutene, 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;

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- 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 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.

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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 Old Linn and Citizen. Under management services agreements (MSAs), Old 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 prospectus 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 prospectus should not be construed as accurate estimates of the current fair value of our proved reserves.

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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 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 greenhouse gases (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 Commodity Futures Trading Commission (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

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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.

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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. For additional information regarding midstream contracts, see Note 14 to the audited financial statements included in this prospectus.

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

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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.

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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 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 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,

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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.

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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 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. 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 federal Clean Air Act (CAA), lowering the National Ambient Air Quality Standard (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, the U.S. Fish and 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. 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 Energy Policy Act of 2005 (EPAct 2005), the Federal Energy Regulatory Commission (the FERC) has civil penalty authority under the Natural Gas Act of 1938 (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 Federal Trade Commission (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.

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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 Prevention of Significant Deterioration (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 changes in presidential administration, there have been attempts to modify the 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 gas industry remain a possibility, and several states have separately imposed their own regulations on methane emissions from oil and 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 an 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 Oklahoma Corporation Commission (OCC). For example in November 2018, we temporarily suspended operations on one of our wells in Grady County due to seismic activity per OCC regulations.

In response to seismic 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 New 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 ending 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 framework.

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(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; and

(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 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 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.

An active, liquid and orderly trading market for our Class A common stock may not develop or be maintained, and our stock price may be volatile.

Upon any future listing by us on a national securities exchange, an active, liquid and orderly trading market for our Class A common stock may not develop or be maintained. Active, liquid and orderly trading markets usually result in less price volatility and more efficiency in carrying out investors purchase and sale orders. The market price of our Class A common stock could vary significantly as a result of a number of factors, some of which are beyond our control. In the event of a drop in the market price of our Class A common stock, you could lose a substantial part or all of your investment in our Class A common stock. Consequently, you may not be able to sell shares of our Class A common stock at prices equal to or greater than the price paid by you.

The following factors could affect our stock price:

- our operating and financial performance and drilling locations, including reserve estimates;
- quarterly variations in the rate of growth of our financial indicators, such as net income per share, net income and revenues;
- the public reaction to our press releases, our other public announcements and our filings with the SEC;
- strategic actions by our competitors;
- changes in revenue or earnings estimates, or changes in recommendations or withdrawal of research coverage, by equity research analysts;
- speculation in the press or investment community;
- the failure of research analysts to cover our Class A common stock;
- sales of our Class A common stock by us or the selling stockholders or the perception that such sales may occur;
- changes in accounting principles, policies, guidance, interpretations or standards;

additions or departures of key management personnel;

actions by our stockholders;

general market conditions, including fluctuations in commodity prices;

domestic and international economic, legal and regulatory factors unrelated to our performance; and

the realization of any risks described under this Risk Factors section.

The stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our Class A common stock. Securities class action litigation has often been instituted against companies following periods of volatility in the overall market and in the market price of a company s securities. Such litigation, if instituted against us, could result in very substantial costs, divert our management s attention and resources and harm our business, operating results and financial condition.

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

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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 Resources, Inc., the owner of Blue Mountain Midstream, LLC. Please see Certain Relationships and Related Party Transactions Historical Transactions with Affiliates Riviera Resources, Inc.

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 Resources, Inc., the owner of Blue Mountain Midstream, LLC. Messrs. Lovoi and Loyd were members of the board of directors of Jones Energy, Inc. Please see Certain Relationships and Related Party Transactions Historical Transactions with Affiliates.

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

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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. Please see Description of Capital Stock Corporate Opportunity.

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.

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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.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information in this prospectus includes forward-looking statements. All statements, other than statements of historical fact included in this prospectus, 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 prospectus, the words could, believe, anticipate, intend, estimate, expect, project and si 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 keep in mind the risk factors and other cautionary statements described under the heading Risk Factors included in this prospectus.

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 contained in this prospectus that are not historical.

We caution you that 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, incident 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 under Risk Factors in this prospectus.

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.

Should one or more of the risks or uncertainties described in this prospectus occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this prospectus are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this prospectus.

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USE OF PROCEEDS

We are registering these shares of Class A common stock for resale by the selling stockholders. We will not receive any proceeds from the sale of shares offered by this prospectus.

DIVIDEND POLICY

We do not anticipate declaring or paying any cash dividends to holders of our Class A common stock in the foreseeable future. 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.

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SELECTED HISTORICAL AND UNAUDITED PRO FORMA FINANCIAL DATA

Roan Resources, 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 prospectus (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 prospectus, (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 Old Linn in connection with the Contribution.

The selected historical statement of operations data for the years ended December 31, 2018, 2017 and 2016 was derived from the audited historical financial statements of Roan Inc. included elsewhere in this prospectus. The selected historical balance sheet data as of December 31, 2018 and 2017 was derived from the audited historical financial statements of Roan Inc. included elsewhere in this prospectus. The selected historical balance sheet data as of December 31, 2016 and the balance sheet and statement of operations data as of and for the year ended December 31, 2015 was derived from audited financial statements and the notes thereto that are not included in this prospectus. The selected historical balance sheet and statement of operations data as of and for the period ended December 31, 2014 was derived from the unaudited financial statements of our predecessor that are not included in this prospectus.

Our historical results are not necessarily indicative of future results. You should read the following table in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and the historical and pro forma financial statements and accompanying notes included elsewhere in this prospectus.

The selected unaudited pro forma condensed statement of operations data for the year ended December 31, 2018 has been prepared to give pro forma effect to the Reorganization as if it had occurred on January 1, 2018. The selected unaudited pro forma condensed financial data is provided for illustrative purposes only and is not indicative of the results that actually would have occurred had the transactions been in effect on the dates or for the periods indicated, or of results that may occur in the future.

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	Pro Forma Year Ended December 31, 2018 (Unaudited)	Year Ended December 31, 2018	2017(1)	2016	2015	2014 (2) (Unaudited)
	(In thousands, except per share data)					
Statement of Operations Data:						
Revenues(3):						
Oil	$ 275,239	$ 275,239	$ 76,876	$ 30,565	$ 3,972	$ 65
Natural gas	76,056	76,056	49,211	16,093	1,055	115
Natural gas liquids	88,472	88,472	40,298	8,307	658	26
Gain (loss) on derivative contracts	78,054	78,054	(6,797)			
Total revenues	517,821	517,821	159,588	54,965	5,685	206
Operating Expenses(3):						
Production expenses	47,600	47,600	16,872	5,090	549	83
Gathering, transportation and processing			18,602	5,920	273	6
Production taxes	17,579	17,579	3,685	1,087	190	12
Exploration expenses	43,303	43,303	32,629	5,258	121	24
Depreciation, depletion, amortization and accretion	123,922	123,922	37,376	24,996	2,091	66
General and administrative	56,297	60,874	31,357	5,581	2,074	344
Gain on sale of oil and natural gas properties			(838)			
Total operating expenses	288,701	293,278	139,683	47,932	5,298	535
Operating income (loss)	229,120	224,543	19,905	7,033	387	(329)
Other income (expense):						
Interest expense	(8,352)	(8,352)	(1,461)	(86)		
Other income			13		4	2
Total other income (expense)	(8,352)	(8,352)	(1,448)	(86)	4	2
Income tax expense(4)	56,296	356,862				
Net income (loss)	$ 164,472	$ (140,671)	$ 18,457	$ 6,947	$ 391	$ (327)
Net income (loss) per share:						
Basic and diluted	$ 1.08	$ (0.92)				
Weighted average shares outstanding:						
Basic and diluted	152,540	152,232				

Balance Sheet Data (at period end):						
Total assets		$ 2,749,109	$ 1,885,592	$ 363,083	$ 113,053	$ 16,618
Total liabilities		$ 1,254,075	$ 300,823	$ 88,836	$ 14,761	$ 1,492
Total equity		$ 1,495,034	$ 1,584,769	$ 274,247	$ 98,292	$ 15,126
Other Financial Data:						
Adjusted EBITDAX(5)	$ 299,342	$ 299,342	$ 97,549	$ 37,287	$ 2,603	$ (237)
Net Debt(5)		$ 507,756	$ 83,868	$ 13,147	NM	NM

(1) On August 31, 2017, Old Linn contributed certain oil and natural gas assets to Roan LLC. The revenue and operating expenses associated with these assets for the period from contribution through December 31, 2017 is included in our results for the year ended December 31, 2017.

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

(3) Revenue and operating expenses 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.

(4) The pro forma data reflects pro forma tax expense based on the statutory tax rate of 25.5% at December 31, 2018 to prospective periods. As described under Reorganization, Roan Inc. was formed in conjunction with the Reorganization. Roan Inc. is taxable as a corporation under the Code, 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 federal income tax purposes, were deemed to pass to the members. Accordingly, no tax provision was made in the historical financial statements of Roan LLC since the income tax was an obligation of the members. The pro forma data excludes the income tax expense associated with the initial deferred tax liability recognized as a result of the Reorganization. The initial recording of the deferred tax liability has been reflected in the historical financial statements, but is not included in the pro forma data due to its non-recurring nature.

(5) Adjusted EBITDAX and Net Debt are non-GAAP financial measures. For a definition of Adjusted EBITDAX and a reconciliation of Adjusted EBITDAX to net income (loss) and a reconciliation of Net Debt to long-term debt, please see Summary Non-GAAP Financial Measure.

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MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

Overview

We are an independent oil and 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. Our objective is to maximize shareholder value and corporate returns by generating steady production growth, strong pre-tax margins and significant cash flow.

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.

Market Conditions

The oil and natural gas industry is cyclical and commodity prices are highly volatile. 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 the lowest NYMEX prices were $27.45 per Bbl and $1.64 per MMBtu, respectively. Oil and natural gas prices began to recover and reached levels as high as $76.41 per Bbl and $4.84 per MMBtu, respectively, during the year ended December 31, 2018, but started to decline again towards the end of 2018, reaching levels as low as $55.80 per Bbl and $2.66 per MMBtu during March 2019. We expect that these markets will continue to be volatile in the future. Our revenue, profitability and future growth are highly dependent on the prices we receive for our oil and natural gas production, including NGLs that are extracted from our natural gas during processing. 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. Please see 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.

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Lower commodity prices not only reduce our revenue and cash flows, but also may limit the amount of oil, natural gas and NGL reserves that we can develop economically and therefore potentially lower our reserves. Lower commodity prices in the future could also result in impairments of our properties. The occurrence of any of the foregoing could materially and adversely affect our future business, financial condition, results of operations, operating cash flows, liquidity or ability to finance planned capital expenditures. Alternatively, commodity prices may increase and such derivative arrangements could limit the benefit we would receive from increases in the prices for oil, natural gas and NGLs.

Drilling Activity

We took over as operator in May 2018 of the oil and natural gas properties contributed to us by Citizen and Old Linn. Our core development area is located across approximately 170,000 acres in the Merge, SCOOP and STACK plays within the Anadarko Basin. In the first quarter of 2019, we reduced our rig count to four rigs across all of our properties. As of December 31, 2018, we operated 591 gross wells and had an interest in an additional 672 gross wells throughout our area of operations.

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.

Please see Sources of Revenue, Production Volumes, Principal Components of Our Cost Structure and Adjusted EBITDAX for a discussion on these metrics.

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 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.

Realized Prices on the Sales of Oil, Natural Gas and NGLs 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.

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 measured against the year ended 2017. The following table sets forth our average oil and natural gas prices received on the oil, natural gas and NGL production sold for the years ended December 31, 2018, 2017 and 2016:

	Year Ended December 31,		
	2018	2017	2016
Average prices(1):			
Oil (per Bbl)	$ 63.07	$ 52.87	$ 41.36
Natural gas (per Mcf)	$ 1.82	$ 2.80	$ 2.52
NGLs (per Bbl)	$ 19.27	$ 26.44	$ 15.21
Total realized price per Boe	$ 27.59	$ 28.16	$ 23.40
Average realized prices after effects of derivative settlements(1)(2):			
Oil (per Bbl)	$ 55.87	$ 53.57	$ 41.36
Natural gas (per Mcf)	$ 1.73	$ 2.89	$ 2.52
NGLs (per Bbl)	$ 19.60	$ 26.44	$ 15.21
Total realized price per Boe	$ 25.50	$ 28.60	$ 23.40

(1) Average prices 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.

(2) Excludes settlement of derivative contracts prior to their contractual maturity.

Pricing for certain of our natural gas contracts are based on Oklahoma indexes, including ONEOK Gas Transportation (OGT), 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.

Production Volumes

The following table presents historical production volumes for our properties for the years ended December 31, 2018, 2017 and 2016:

	Year Ended December 31,		
	2018	2017	2016
Total sales volumes:			
Oil (MBbls)	4,364	1,454	739
Natural gas (MMcf)	41,890	17,582	6,382
NGLs (MBbls)	4,592	1,524	546
Total (MBoe)	15,938	5,908	2,349
Average daily total volumes (MBoe)	43.7	16.2	6.3

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As reservoir pressures decline, production volumes from a given well or formation decreases and production expenses may increase. Growth in our future production and reserves will depend on our ability to continue to add proved reserves in excess of production. Our ability to increase reserves through development projects and acquisitions is dependent on many factors, including infrastructure capacity in our areas of operation, our ability to raise capital, our ability to obtain regulatory approvals, and our ability to successfully identify and consummate acquisitions. Please see Critical Accounting Policies and Estimates for further discussion.

Derivative Contracts Activity

Our primary market risk exposure is in the price we receive for our oil, natural gas, and NGLs production. Pricing for oil, natural gas and NGLs 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 in settlement of derivative contracts are reflected as gain or loss on derivative contracts included in the statement of operations. Please see Quantitative and Qualitative Disclosure About Market Risk Commodity Price Risk for further discussion.

We have historically relied on commodity derivative contracts to mitigate our exposure to lower commodity prices. However, 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 hedging strategy and future hedging transactions will be determined primarily at our discretion and may differ from historical hedging activity. Further, under our credit facility, we are prohibited from hedging in excess of (a) 80% of reasonably anticipated projected production for the thirty (30) month period following the date of any hedging transaction and (b) 80% of reasonably anticipated projected production from proved reserves for the second thirty (30) month period following the date of any hedging transaction. If the amount of borrowings outstanding exceeds 50% of the borrowing base, we are required to enter into and maintain on a quarterly basis hedge transactions permitted by the credit facility with respect to not less than 50% of reasonably anticipated quarterly production volumes for oil and natural gas from proved developed reserves for the next eight quarters following the most recent quarter end. As of December 31, 2018, we were in compliance with these requirements under our credit facility.

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.

For more information on our open positions executed as of December 31, 2018, please see Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk.

We expect to continue to use commodity derivative instruments to hedge our price risk in the future. Our hedging strategy and future hedging transactions will be determined at the discretion of our board of directors and may be different than our historical hedging practices.

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. Please see Critical Accounting Policies and Estimates Oil and Natural Gas Properties for further discussion.

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. Please see Critical Accounting Policies and Estimates for further discussion.

General and administrative. General and administrative (G&A) costs 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.

Adjusted EBITDAX

Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management and other users of our financial statements. We define Adjusted EBITDAX as net income (loss) adjusted for interest expense, depreciation, depletion, amortization and accretion, income tax expense, exploration costs, non-cash equity-based compensation expense, gain on early termination of derivative contracts, non-cash (gain) loss on derivative contracts, reorganization transaction costs and expense for allowance for doubtful accounts. Please see Summary Historical and Unaudited Pro Forma Financial Data Non-GAAP Financial Measure Adjusted EBITDAX and Net Debt for a discussion on this metric. Our predecessor, Roan LLC, passed through its taxable income to its owners for income tax purposes and, thus, we have not incurred historical income tax expenses.

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 in September 2018 to serve as a holding company and, prior to the Reorganization, had no previous operations, assets or liabilities. For more information on our Reorganization and the ownership of our Class A common stock by our principal stockholders, please see Prospectus Summary Recent Developments History and Reorganization and Principal and Selling Stockholders and the unaudited pro forma financial statements included elsewhere in this prospectus.

The historical financial statements included elsewhere in this prospectus (i) on and after September 24, 2018, are that of Roan, Inc., and (ii) prior to September 24, 2018, are that of Roan LLC, our predecessor. The historical financial and operational information of Roan LLC presented in this prospectus, (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 Linn Contributed Business. The pro forma financial information presented in this prospectus treats the Reorganization as if the Reorganization happened on January 1, 2018. As a result, the historical financial data and pro forma financial information presented in this prospectus may not give you an accurate indication of what our actual results would have been if our Reorganization had been completed at the beginning of the periods presented.

Public Company Expenses

Subsequent to the Reorganization, we incur direct, incremental G&A expenses as a result of becoming 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

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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 to the audited consolidated financial statements included elsewhere in this prospectus.

Historical Results of Operations and Operating Expenses

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

	Year 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 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.

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

Revenues

The following table provides information on our operating revenues:

	Year 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 Old 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 Old 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 Old 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:

	Year Ended December 31,	
	2018	2017
	(in thousands, except 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.

(2) General and administrative expenses for the year 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.

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 Old 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 following the Reorganization.

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

	For the Year 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	6.3
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(1):		
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

(1) Excludes settlement of derivative contracts prior to their contractual maturity.

Revenues

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

	For the Year 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 Old 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 Old 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 Old 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.

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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:

	For the Year 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 Old Linn and costs associated with seismic information acquired in 2017.

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 Old 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

The following table summarizes our cash flows for the periods indicated:

	Year 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 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.

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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 $11.1 million of distributions to Citizen members and repayments of $40.0 million on Citizen s credit facility.

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 year 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, contributions from Citizen members of $95.6 million, partially offset by $40.0 million repayment of borrowings 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.

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.

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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 as operator in May 2018 on the oil and natural gas properties contributed to us by Citizen and Old 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 Old 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.

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, as amended, provides for commitments of $750.0 million, subject to a borrowing base that will be redetermined semi-annually each April 1 and October 1 by the lenders in their sole discretion. As of December 31, 2018, the borrowing base under our existing credit facility was $675.0 million. As of December 31, 2018, we had $514.6 million of borrowings and no letters of credit outstanding under our existing credit facility, with $160.4 million of additional borrowing capacity available.

Amounts borrowed under the credit facility bear interest at the London Interbank Offered Rate (LIBOR) or the alternate base rate (ABR) at our election. The rate sed 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 or 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.

At December 31, 2018, the weighted average interest rate on borrowings under our existing credit facility was 5.21%. We also pay a commitment fee on unused amounts of our existing credit facility of 0.375% to 0.50%. We may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs.

Our 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.

Our credit facility also requires us to maintain compliance with the following financial ratios:

a leverage ratio, which is the ratio of Consolidated Total Debt (as defined in our credit facility) to Consolidated EBITDAX (as defined in our credit facility) for the rolling four fiscal quarter period ending on the last day of the applicable quarter, of not greater than 4.0 to 1.0; and

a current ratio, which is the ratio of our consolidated current assets (including unused commitments under our credit facility and excluding non-cash assets under FASB ASC 815 and 410) to our

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consolidated current liabilities (excluding the current portion of long-term debt under our credit facility, non-cash liabilities under ASC 815 and 410), of not less than 1.0 to 1.0.

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

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 expense 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.

Quantitative and Qualitative Disclosure About Market Risk

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

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Commodity Price Risk

The following table provides a summary of our open commodity contracts at 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 (MMBtu)	1,095,000		1,095,000
Weighted-average price	$ 32.25	$	$ 32.25

We are exposed to market risk related to the changes in the pricing applicable to our oil, natural gas and NGLs production. The prices of our commodities are subject to fluctuations resulting from changes in supply and demand. Pricing for oil and natural gas production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future.

We use derivatives, including fixed price swaps and basis swaps, to reduce price volatility associated with certain of our oil and natural gas sales. With respect to these fixed price swap contracts, when the reference 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. Similarly, 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 NGLs 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 our oil, natural gas and NGLs receivables with two significant purchasers. We do not believe the loss of any single purchaser would materially impact its 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 alternate base rate, in each case adjusted upward by an applicable margin based on the utilization percentage of the credit facility.

At December 31, 2018, we had $514.6 million of debt outstanding, with a weighted average interest rate on these borrowings of 5.21%. Interest is calculated under the terms of our existing credit facility based on certain specified base rates plus an applicable margin that varies based on utilization. Interest is calculated under our existing term loan facility based on certain specified base rates plus an applicable margin. Assuming no change in the amount outstanding, the impact on interest expense of a 1% increase or decrease in the assumed weighted average interest rate would be $5.1 million per year.

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.

Recently Issued Accounting Standards

For a discussion of recently issued accounting standards, please see Note 3 to the audited 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 proved 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 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 predominantly 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 estimates 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 accumulate depreciation, depletion and amortization unless doing so significantly affect 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 transactions, we will 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 statements of operations.

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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 income taxes, 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 now taxed as a corporation. 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.

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.

BUSINESS

Our Company

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. Our objective is to maximize shareholder value and corporate returns by generating steady production growth, strong pre-tax margins and significant cash flow.

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 3, 2018, we held leasehold interests in approximately 383,000 gross (172,000 net) acres in the Anadarko Basin. As of 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).

We have chosen to focus our development efforts on the Merge play, as we believe it benefits from the following attributes:

Stacked Formations. The Merge has been proven to be prospective for two primary resource formations: the Mayes (Meramec/Sycamore equivalent) formation and the Woodford formation. We and our predecessors have demonstrated successful economic development of both benches, with 63 gross (53 net) and 80 gross (65 net) horizontal operated wells producing from the Mayes and Woodford formations, respectively.

Reservoir Quality. Reservoir characteristics from petrophysical analysis demonstrate high porosity and permeability development in the Merge as compared to other unconventional plays.

Phase Window Positioning. The thermal maturity of the source rock throughout the eastern portion of the Merge results in production profiles characterized by high percentages of oil and NGLs. Specifically, over 80% of our operated acreage is within areas we believe demonstrate higher percentage production of oil and NGLs within the Merge play.

Pressure Gradients. Geopressure across our operated acreage position in the Merge play ranges from slightly to significantly overpressured at approximately 0.45 to 0.65 pounds psi per foot of true vertical depth, resulting in superior well deliverability and improved GOR trend stability as compared to normal to under-pressured reservoirs.

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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.

The table below provides a summary of our acreage position as of December 31, 2018:

	Total
Operated Sections	313
Operated Acres	122,254
Non-Operated Acres	49,717
Total Acres	171,970
% HBP	84%
% Operated	71%

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 EURs 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.

Reserves Information

The following table provides summary information regarding our proved reserves as of December 31, 2018, based on a reserve report prepared by DeGolyer and MacNaughton, our independent reserve engineers.

Estimated Total Proved Reserves							
Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	PV-10 ($)(1)(2)	% Oil	% Liquids	% Developed
55.7	98.4	911.2	306.0	2,091,509	18.2	50.4	39.3

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(1) Presented in thousands. 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. Please see Risk Factors The standardized measure of our estimated reserves contained in this prospectus and in the footnotes to our financial statements is not an accurate estimate of the current fair value of our estimated reserves. 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. Please see Summary Historical and Unaudited Pro Forma Financial Data Non-GAAP Financial Measure PV-10 .

(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.

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. We consider our extensive inventory of high-potential, oil and liquids-weighted drilling locations to be relatively low-risk based on information gathered from over 400 horizontal wells developed since early 2014, of which 152 were drilled by us or our predecessors, and over 4,450 vertical wells developed in our development area, industry activity surrounding our acreage, subsurface data, including well cores and logs and 3-D seismic and the consistent geology surrounding our position.

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. Our management and technical teams intend to apply their operational expertise, data gained from our large acreage position in the Merge play and available third-party data to deploy advanced drilling, completion and production management technologies that maximize well productivity and control capital and operating costs. 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. Our highly experienced management and technical teams have a substantial track record of developing unconventional plays, which we believe is instrumental in our achievement of these operational and capital efficiencies.

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. We will adjust the size of our rig program to optimize our overall development program and with a view to limiting the lag time between the development of parent and child wells. Through these measures, we seek to target an optimal combination of net present value and rate of return associated with the development of a particular unit. According to RS Energy Group, child wells are generally at least 25% more productive if drilled within 1.5 years of the development of the parent well, as compared to child wells drilled 1.5 to 3 years following the development of the parent well. Operational and developmental control positions us to minimize the adverse impacts associated with this time lag.

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. Consistent with our disciplined approach to financial management, we have an active commodity hedging program that seeks to reduce our exposure to downside commodity price volatility, enabling us to protect future cash flows and maintain liquidity to fund our development program.

Selectively pursue opportunities to augment our asset base through the disciplined acquisition or leasing of oil and natural gas properties. 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. Operatorship of our position allows us the flexibility to control the pace of our development plan, as well as the lengths of our laterals and our drilling and well completion techniques.

Long-lived inventory of locations with predictable production profiles that provide high rate-of-return development opportunities. Through the drilling of over 163 operated horizontal wells and participation in over 317 non-operated horizontal wells across our acreage, we have substantially

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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. While oil represents a significant portion of our total revenues, natural gas and NGLs comprise a majority of our reserves and production. While we believe we have favorable realized price differentials for natural gas and NGLs compared to other basins, our realized natural gas price differential is based on the sales price at multiple hubs and our NGLs are sold on a product by product basis. 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. Joel Pettit, our Executive Vice President Operations and Marketing, worked in EOG s Mid-Continent Division for over a decade. Greg Condray, our Executive Vice President Geosciences and Business Development, worked with Mr. Pettit in EOG s Mid-Continent Division as Division Exploration Manager, and had considerable experience at Chesapeake Energy leading initial delineation and development efforts in the Eagle Ford, Haynesville and Powder River Basin. 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 held by production 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.

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Historical Capital Expenditures and Capital Budget

Our 2019 capital budget is approximately $520 million to $570 million. For the year ended December 31, 2018, our aggregate drilling and completion capital expenditures were approximately $705.2 million.

Because we are the operator of a high percentage of our acreage and a majority of our acreage is held by production, the amount and timing of our capital expenditures is 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, and prevailing and anticipated prices for oil and natural gas. A deferral of planned capital expenditures, particularly with respect to drilling and completing new wells, could result in a reduction in anticipated production and cash flows and loss of acreage through lease expirations. In addition, we may be required to reclassify some portion of our reserves currently booked as proved undeveloped reserves to no longer be proved reserves if such a deferral of planned capital expenditures means we will be unable to develop such reserves within five years of their initial booking.

Our Properties

The map below depicts the location of our properties as of December 31, 2018.

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 prospectus. 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 on production.

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 (501 net) producing wells online, operated and non-operated.

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 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 Society of Petroleum Engineers.

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 the registration statement of which this prospectus forms a part.

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 is primarily responsible for overseeing the preparation of the reserves estimates by DeGolyer and MacNaughton. Our Corporate Reserves Advisor 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 assists our Corporate Reserves Advisor in the reserves preparation process. He has 13 years of industry experience in reserve estimation and petroleum economics and holds a Bachelor of Science in engineering and geology as well as a Master degree in Business Administration. 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.

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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 proved developed non-producing (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.

		As of December 31, 2018(1)
Proved developed reserves:		
Oil (MBbls)		18,652
Natural gas (MMcf)		369,677
NGLs (MBbls)		39,927
Total (MBoe)(2)		120,192
Proved undeveloped reserves:		
Oil (MBbls)		37,031
Natural gas (MMcf)		541,505
NGLs (MBbls)		58,485
Total (MBoe)(2)		185,767
Total proved reserves:		
Oil (MBbls)		55,683
Natural gas (MMcf)		911,182
NGLs (MBbls)		98,412
Total (MBoe)(2)		305,959
Benchmark Oil and Natural Gas Prices(1):		
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) 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.

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

(3) Please see Risk Factors The standardized measure of our estimated reserves contained in this prospectus 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. Please see Summary Historical and Unaudited Pro Forma Financial Data Non-GAAP Financial Measure PV-10.

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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 prospectus.

Additional information regarding our proved reserves can be found in the notes to our financial statements included elsewhere in this prospectus and in the reserve report of DeGolyer and MacNaughton as of December 31, 2018, which is included as an exhibit to the registration statement of which this prospectus forms a part.

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 were 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 Risks Related to Our Business 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.

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Oil and Natural Gas Production Prices and Costs

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:

	Year Ended December 31,		
	2018	2017	2016
Production data:			
Oil (MBbls)	4,364	1,454	739
Natural gas (MMcf)	41,890	17,582	6,382
NGLs (MBbls)	4,592	1,524	546
Total (MBoe)(1)	15,938	5,908	2,349
Average daily production (MBoe/d)	43.7	16.2	6.4
Average prices(2):			
Oil (per Bbl)	$ 63.07	$ 52.87	$ 41.36
Natural gas (per Mcf)	$ 1.82	$ 2.80	$ 2.52
NGLs (per Bbl)	$ 19.27	$ 26.44	$ 15.21
Total (per Boe)	$ 27.59	$ 28.16	$ 23.40
Average realized prices after effects of derivative settlements(2):			
Oil (per Bbl)	$ 55.87	$ 53.57	$ 41.36
Natural gas (per Mcf)	$ 1.73	$ 2.89	$ 2.52
NGLs (per Bbl)	$ 19.60	$ 26.44	$ 15.21
Total (per Boe)	$ 25.48	$ 28.60	$ 23.40
Average costs (per MBoe)(2):			
Production expenses	$ 2.99	$ 2.86	$ 2.17
Gathering, transportation and processing expenses	$	$ 3.15	$ 2.52
Production taxes	$ 1.10	$ 0.62	$ 0.46
General and administrative(3)	$ 3.82	$ 5.31	$ 2.38

(1) May not sum or recalculate due to rounding.
(2) Average prices and costs 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.
(3) General and administrative expenses for the year ended December 31, 2018 and 2017 include $0.69 per Boe and $0.06 per Boe, respectively, of equity-based compensation expense.

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
Total:						
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,

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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 Year 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 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.

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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:

	Year Ended December 31,		
	2018	**2017**	**2016**
Coffeyville Resources Refining & Marketing LLC	31%	*	*
Sunoco Inc.	18%	40%	55%
Blue Mountain Midstream, LLC(1)	15%	*	*
EnLink Oklahoma Gas Processing, LP	13%	39%	31%

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

(1) Certain of our directors are directors of Riviera Resources, Inc., which owns Blue Mountain Midstream, LLC. Please see Certain Relationships and Related Party Transactions Historical Transactions with Affiliates Riviera Resources, Inc.

During such periods, no other purchaser accounted for 10% or more of our revenue. We believe that the loss of any of these purchasers would not result in a material adverse effect on our financial condition or results of operations, as oil, natural gas and NGLs 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.

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 were unable to deliver any additional natural gas volumes subsequent to December 31, 2018 through November 2021, we would 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. The Company may be liable for environmental damages caused by previous owners of property it purchases and leases. As a result, the Company 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, the Company participates in wells on a nonoperated basis and therefore may be limited in its ability to control the risks associated with the operation of such wells.

In accordance with customary industry practices, the Company maintains insurance against some, but not all, potential losses. The Company cannot provide assurance that any insurance it obtains will be adequate to cover any losses or liabilities. The Company has elected to self-insure for certain items for which it has 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 the Company s financial position, results of operations and cash flows. For more information about potential risks that could affect the Company, 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 prospectus.

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. 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.

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 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

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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 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 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

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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 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 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 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.

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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, although 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 USACE 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 recent seismic events near belowground disposal wells used for the injection of produced water resulting from oil and 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 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 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 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 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 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 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 gas industry remain a possibility, and several states have separately imposed their own regulations on methane emissions from oil and 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 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. 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 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 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 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 Permits and Authorizations

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

Related Insurance

We maintain insurance against some risks associated with above or underground contamination that may occur as a result of our exploration and production activities. 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.

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Employees

As of April 15, 2019, 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.

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.

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MANAGEMENT

The following table sets forth the names, ages (as of April 17, 2019) and titles of our directors and executive officers.

Name	Age	Position
Joseph A. Mills	59	Executive Chairman
Joel L. Pettit	63	Executive Vice President Operations and Marketing
Greg T. Condray	49	Executive Vice President Geoscience and Business Development
David M. Edwards	37	Chief Financial Officer
Amber N. Bonney	44	Vice President and Chief Accounting Officer
David C. Treadwell	41	Vice President, General Counsel and Corporate Secretary
Matthew Bonanno	40	Director
Evan Lederman	39	Director
John V. Lovoi	58	Director
Paul B. Loyd, Jr.	72	Director
Michael P. Raleigh	62	Director
Andrew Taylor	41	Director
Anthony Tripodo	66	Director

Joseph A. Mills has served on our board of directors since November 2018. Mr. Mills was appointed as Executive Chairman and will serve as the principal executive officer, in each case, on an interim basis until his respective successor is appointed. Mr. Mills currently serves as the President and Chief Executive Officer of Samson Resources II, LLC, a privately held exploration and production company with assets located in the Powder River Basin and Green River Basin of Wyoming, a position he has held since February 2017. Prior to joining Samson Resources II, LLC, Mr. Mills served as a director of CUI Global, Inc. (NASDAQ: CUI) from August 2015 to October 2016 and served as Chairman and Chief Executive Officer of Eagle Rock Energy G&P, LLC, the general partner of the general partner of Eagle Rock Energy Partners, L.P. (NASDAQ: EROC), from May 2007 until it merged with Vanguard Natural Resources, LP (NASDAQ: VNR) in October 2015. Mr. Mills also served as Chief Executive Officer and as a manager of Montierra Management LLC (Montierra), which is the general partner of Montierra Minerals & Production, LP, from 2006 to October 2016. From 2003 to 2006, Mr. Mills was the Senior Vice President of Operations for Black Stone Minerals Company, LP, a privately held company. From 2001 to 2003, Mr. Mills was a Senior Vice President of El Paso Production Company, and from 1999 to 2001, Mr. Mills was a Vice President of El Paso Production Company, a wholly owned subsidiary of El Paso Corporation. Prior to joining El Paso, Mr. Mills held various executive and senior-level management positions with Sonat Exploration Company, a wholly owned subsidiary of Sonat, Inc. Mr. Mills holds a Bachelor of Business Administration degree in Petroleum Land Management from the University of Texas, Austin and a Master of Business Administration degree in Finance from the University of Houston. Pursuant to the Stockholders Agreement, Mr. Mills was designated to the board of directors by Roan Holdings.

The board of directors believes that Mr. Mills background in the energy industry and experience serving on the board of directors of other energy companies bring valuable leadership and insight to the board of directors and the Company.

Joel L. Pettit has served as our Executive Vice President Operations and Marketing since September 2018 and as the Executive Vice President Operations and Marketing of Roan LLC since November 2017. Prior to that, Mr. Pettit served as an executive consultant from May 2016 to October 2017, and as the Division Operations Manager of both the Mid-continent Division and the Permian Division of EOG Resources, Inc. from 2006 to April 2017. Mr. Pettit has more than 35 years of experience in the oil and gas industry, 22 of which were spent at Pennzoil where he served in a variety of technical roles, including Operations Engineer and Manager. Mr. Pettit graduated from Mississippi State University where he earned a Bachelor of Science degree in Petroleum Engineering.

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Greg T. Condray has served as our Executive Vice President Geoscience and Business Development since September 2018 and as Executive Vice President Geoscience and Business Development of Roan LLC since November 2017. Mr. Condray has 22 years of experience in the oil and gas industry, having previously worked as Division Exploration Manager in the Mid-Continent Division for EOG Resources, Inc. from October 2013 to April 2017, where he was instrumental in assembling its position in the Merge area of Oklahoma. From September 2006 to October 2013 he worked at Chesapeake Energy Corporation, where he was responsible for the exploration of their Eagleford shale play and the development of their Haynesville and Powder River Basin assets, and from May 2017 until he joined us, he had been evaluating potential opportunities. Mr. Condray graduated from the University of Alabama where he earned a Master of Science and Bachelor of Science degree in Geology.

David M. Edwards has served as our Chief Financial Officer since September 2018 and as Chief Financial Officer of Roan LLC since June 2018. Prior to joining us, Mr. Edwards served as Senior Vice President and Chief Financial Officer of Tapstone Energy Inc. and its affiliates from October 2014 to June 2018. Mr. Edwards also served as Senior Vice President of Finance of Tapstone Energy, LLC from April 2014 to October 2014. Prior to joining Tapstone Energy, LLC, Mr. Edwards held various roles in the Finance department of SandRidge Energy, Inc. from October 2010 to February 2014. From 2007 until 2010, Mr. Edward worked in Equity Research at UBS Investment Bank, covering publicly traded companies in the Energy sector. Mr. Edwards holds a Bachelor of Science degree in Applied Mathematics from Brown University.

Amber N. Bonney has served as our Chief Accounting Officer since September 2018 and has served as a Vice President since February 2019 and as the Chief Accounting Officer of Roan LLC since January 2018. Prior to joining us, Ms. Bonney served as the Controller for Permian Resources, LLC, an Oklahoma City-based private company focused on the acquisition and development of unconventional oil and natural gas resources in the Permian Basin, from November 2015 to December 2017. Prior to her employment with Permian Resources, LLC, Ms. Bonney served as the Vice President of Accounting from February 2015 to November 2015 and the Director of Financial Reporting from May 2014 to February 2015 at New Source Energy Partners, LP. New Source Energy Partners, LP filed for liquidation under Chapter 7 of the United States Bankruptcy Code in March 2016. Prior to that, Ms. Bonney served in various capacities, including as controller, at SandRidge Energy, Inc. from March 2008 until May 2014. Ms. Bonney also worked in the internal audit group at Devon Energy Corporation and was a manager at PricewaterhouseCoopers LLP prior to her time at SandRidge Energy, Inc. Ms. Bonney received her Bachelor of Business Administration degree in Accounting and Finance from the University of Oklahoma. Ms. Bonney is also a Certified Public Accountant.

David C. Treadwell has served as our General Counsel and Corporate Secretary since September 2018 and has served as a Vice President since February 2019. Mr. Treadwell previously served as a consultant to Patterson-UTI Energy Inc. from May 2017 to November 2017, where he provided legal and managerial assistance during the merger transition after Patterson-UTI acquired Seventy Seven Energy Inc. Prior to that, he served as Senior Vice President, General Counsel and Secretary of Seventy Seven Energy Inc. upon consummation of its spin-off from Chesapeake Energy Corporation in June 2014. From June 2011 to June 2014, Mr. Treadwell served as Lead Counsel and then as Vice President Legal and Chief Counsel at Chesapeake Energy Corporation. Mr. Treadwell also served as General Counsel of Bronco Drilling Company, Inc. from July 2007 until it was acquired by Chesapeake Energy Corporation in June 2011. Prior to joining the Company, Mr. Treadwell was evaluating potential opportunities from November 2017 until August 2018. Mr. Treadwell holds a Juris Doctorate, with highest honors, from the University of Oklahoma College of Law and a Bachelor of Science degree in Finance from the University of Illinois at Urbana-Champaign.

Matthew Bonanno has served on our board of directors since September 2018. Mr. Bonanno joined York Capital Management (York) in July 2010 and is a Partner of the firm. Mr. Bonanno joined York from the Blackstone Group, where he worked as an associate focusing on restructuring, recapitalization and reorganization transactions. Prior to joining the Blackstone Group, Mr. Bonanno worked on financing and strategic transactions at News Corporation and as an investment banker at JP Morgan and Goldman Sachs. In addition to Roan, Mr. Bonanno, in his capacity as a York employee, is currently a member of the boards of Riviera, Rever Offshore AS, Samson Resources II, LLC, all entities incorporated pursuant to York s partnership with Costamare Inc., NextDecade Corp. and Vantage Drilling Co. Prior to the Reorganization, Mr. Bonanno was a member of the boards of Roan LLC and New Linn. He is also a member of the board of directors of the Children s Scholarship Fund. Mr. Bonanno received a Bachelor degree in History from Georgetown University and a Master of Business Administration degree in finance from The Wharton School of the University of Pennsylvania.

The board of directors believes Mr. Bonanno s extensive investment and restructuring experience in the energy industry brings valuable strategic and analytical skills to our board of directors.

Evan Lederman has served on our board of directors since September 2018. Mr. Lederman is a Managing Director, Co-Head of Restructuring and Partner on the Investment Team at Fir Tree Partners. Mr. Lederman focuses on the funds distressed credit and special situation investment strategies, including co-managing its energy restructuring initiatives. Prior to joining Fir Tree Partners in 2011, Mr. Lederman worked in the Business Finance and Restructuring groups at Weil, Gotshal & Manges LLP and Cravath, Swaine & Moore LLP. In addition to Roan, Mr. Lederman, in his capacity as a Fir Tree Partners employee, is currently a member of the boards of Riviera, Ultra Petroleum Corp. (Chairman), Amplify Energy Corp., New Emerald Energy LLC, and Deer Finance, LLC. Prior to the Reorganization, Mr. Lederman was a member of the boards of Roan LLC and New Linn. Mr. Lederman received a Juris Doctorate degree with honors from New York University School of Law and a Bachelor of Arts, magna cum laude, from New York University.

The board of directors believes Mr. Lederman s considerable experience as a member of the boards of directors of exploration and production companies, as well as his extensive investment and restructuring experience in the energy industry, his brings valuable strategic and analytical skills to our board of directors.

John V. Lovoi has served on our board of directors since September 2018. Mr. Lovoi is the founder of JVL Advisors, LLC, a Houston based asset manager specializing in upstream oil and gas investments, and has served as the managing partner since it was founded in 2003. Mr. Lovoi is sole member of, and exercises investment management control over, JVL, an entity that may be deemed to beneficially own all securities held by Roan Holdings through its indirect majority ownership interest in Roan Holdings and its contractual right to nominate a majority of Roan Holdings board of managers, which exercises voting and dispositive power over all securities held by Roan Holdings. Mr. Lovoi has approximately 30 years of experience in oil and gas research, investment banking and investments. Prior to forming JVL in 2003, he was the head of Morgan Stanley s oil and gas investment banking practice. Prior to this role, he served as the head of Morgan Stanley s oil and gas equity research practice. Mr. Lovoi currently serves as Chairman of the board of directors for Dril-Quip, Inc, a leading provider of highly engineered offshore drilling products and services, and as Chairman of the board of directors for Epsilon Energy, an integrated upstream and midstream company in the Marcellus Shale. Mr. Lovoi is also a director of Helix Energy Solutions, a leading global provider of well intervention equipment and services to the global offshore oil and gas industry and Mr. Lovoi served as an independent director of Jones Energy, Inc., an oil and gas company, from February 2018 until September 2018. Prior to the Reorganization, Mr. Lovoi was a member of the board of Roan LLC. Mr. Lovoi received a Bachelor of Science degree in Chemical Engineering from Texas A&M University and received his Master of Business Administration with an emphasis on finance and accounting from the University of Texas at Austin.

The board of directors believes that Mr. Lovoi s background in investment banking, as well as his in-depth knowledge of the oil and gas industry generally, qualifies him to serve as a member of our board of directors.

Paul B. Loyd, Jr. has served on our board of directors since September 2018. Mr. Loyd served as chairman and chief executive officer of R&B Falcon Corporation, a diversified drilling company, until 2001 when it merged with

Transocean Sedco Forex. Prior to his tenure at R&B Falcon Corporation, Mr. Loyd accumulated more than 30 years of experience in the energy and energy services industry. He began his career in 1969 with Reading & Bates Offshore Drilling Company, holding various positions both in the United States and overseas, primarily West Africa, the Middle East and the Far East. He also served with Houston Offshore International, Inc. a domestic offshore drilling company, as Chief Financial Officer, Atwood Oceanics, Inc, an international drilling contractor, as Assistant to the President, Griffin-Alexander, Inc., a domestic drilling contractor, as President, and Chiles-Alexander, Inc., as Chief Executive Officer. Mr. Loyd also founded Carrizo Oil & Gas, Inc. In addition to the drilling industry, Mr. Loyd served as a consultant to the Central Planning Organization of the Government of Saudi Arabia and assisted in writing the Five Year Plan for 1975 1980. Mr. Loyd served as an independent director of Jones Energy, Inc. from February 2018 until September 2018 and prior to the Reorganization, served on the board of Roan LLC. Mr. Loyd serves on the board of Roan Holdings, a significant stockholder of the Company. Mr. Loyd graduated from Southern Methodist University with a Bachelor of Business Administration in Economics. Cox School of Business honored Mr. Loyd in 2001 with its Distinguished Alumni Award and in 2012 Paul was named an SMU Distinguished Alumni. He received his Master of Business Administration degree from the Harvard Graduate School of Business.

The board of directors believes Mr. Loyd s significant experience, both in the energy industry broadly and in the Company s specific areas of operation, qualifies him to serve as a member of our board of directors.

Michael P. Raleigh has served on our board of directors since September 2018. Mr. Raleigh has served as chief executive officer and a director for Epsilon Energy Ltd. since July 2013. Before becoming chief executive officer at Epsilon Energy Ltd., he acted in various positions in the global oil and gas business for 35 years, primarily holding positions in the areas of reservoir development strategy, property valuations, completions and production. He has also been managing investments with Domain Energy Advisors since January 2005. Prior to the Reorganization, Mr. Raleigh was a member of the board of Roan LLC. Mr. Raleigh serves on the board of Roan Holdings, a significant stockholder of the Company. Mr. Raleigh received a Bachelor of Science degree in Chemical Engineering from Queens University in Canada and received his Master of Business Administration degree from the University of Colorado.

The board of directors believes that Mr. Raleigh is qualified to serve as a member of our board of directors as a result of his background in engineering, including reserve, acquisitions and valuation engineering, and his experience in the development and appraisal of oil and gas fields.

Andrew Taylor has served on our board of directors since September 2018. Mr. Taylor is a member of the investment team of Elliott Management Corporation (Elliott), a New York-based trading firm, where he is responsible for various corporate investments. Prior to joining Elliott in August 2015, Mr. Taylor was a member of the investment team of BlackRock s Distressed Products Group from April 2009 to August 2015 and prior to that held similar positions at R3 Capital Partners and the Global Principal Strategies team at Lehman Brothers. In addition to Roan, Mr. Taylor, in his capacity as an Elliott employee, is currently a member of the boards of Riviera and Birch Permian Holdings Inc. Prior to the Reorganization, Mr. Taylor was a member of the boards of Roan LLC and New Linn. Mr. Taylor earned a Bachelor of Science degree in Mechanical Engineering from Rose-Hulman Institute of Technology and a Master of Business Administration, with honors, from the University of Chicago Booth School of Business.

The board of directors believes Mr. Taylor s considerable experience in the investment advisory industry brings substantial investment management skills to the board of directors.

Anthony Tripodo has served on our board of directors since September 2018. Mr. Tripodo has also served as Managing Director of Arch Creek Advisors LLC, a financial advisory firm, since January 2018. Prior to his time at Arch Creek Advisors LLC, Mr. Tripodo served as Executive Vice President and Senior Advisor of Helix Energy Solutions Group, Inc. (Helix), a provider of well intervention and robotics services for the offshore oil and gas and renewable energy industries, from June 2017 to December 2017 and previously served as Executive Vice President and Chief Financial Officer from June 2008 to June 2017. Beginning in 2003, Mr. Tripodo served in a number of other roles at Helix, including director and Chairman of the Audit Committee. Prior to joining Helix in 2003, Mr. Tripodo served in various executive and financial leadership roles with Baker Hughes, Veritas

DGC Inc., Tesco Corporation and as a board member of various other energy companies. He has over 35 years of experience in the global energy industry. Mr. Tripodo also served as a manager during his tenure at the accounting firm of Price Waterhouse & Co., which spanned from 1974 to 1980. Mr. Tripodo holds a Bachelor of Arts degree in Business from St. Thomas University. Pursuant to the Stockholders Agreement, Mr. Tripodo was designated to our board of directors by Roan Holdings.

The board of directors believes that Mr. Tripodo s significant energy industry experience, financial expertise and corporate governance experience make him well suited to serve as a member of our board of directors.

Board of Directors

Our board of directors currently consists of eight members. Our Class A common stock is traded on the NYSE. Each of Messrs. Tripodo, Bonanno, Lederman, Taylor, Lovoi, Loyd and Raleigh are independent under the independence standards of the NYSE. Mr. Mills does not meet the independence standards of the NYSE because of his interim role as Executive Chairman and principal executive officer of the Company.

In evaluating director candidates, we have and will continue to assess whether a candidate possesses the integrity, judgment, knowledge, experience, skills and expertise that are likely to enhance the board of directors ability to manage and direct our affairs and business, including, when applicable, to enhance the ability of the committees of the board of directors to fulfill their duties. Our directors hold office until the earlier of their death, resignation, retirement, disqualification or removal or until their successors have been duly elected and qualified.

The board of directors consists of two classes of directors, with Mr. Mills serving a term ending on the date of the Company s 2019 annual general meeting of stockholders, and each of Messrs. Bonanno, Lederman, Lovoi, Loyd, Raleigh, Taylor and Tripodo serving a term ending on the 2020 annual meeting. Following the 2020 annual meeting, the board of directors will cease to be classified and nominations for director shall be made by the board of directors upon the advice of the Company s nominating and corporate governance committee.

Meetings of the Board of Directors

Our board of directors will hold regular and special meetings from time to time as necessary. Regular meetings may be held without notice on dates set by the board of directors. Special meetings of the board of directors may be called with 24 hours notice to each member (unless waived) upon request of the Chairman of the board of directors, the Chief Executive Officer or any two members of the board of directors. A quorum for a regular or special meeting will exist when a majority of the members are participating in the meeting either in person or by conference telephone. Any action required or permitted to be taken at a meeting of the board of directors may be taken without a meeting, without prior notice and without a vote if all of the members sign a written consent authorizing the action.

Leadership Structure

The board of directors determined that Mr. Mills should serve as the Executive Chairman of the board of directors until his respective successor is appointed. Additionally, the board of directors determined that Mr. Tripodo should serve as the lead independent director of the board of directors.

Director Independence

The board of directors reviewed the independence of our directors using the independence standards of the NYSE and, based on this review, determined that Messrs. Tripodo, Bonanno, Lederman, Lovoi, Loyd, Raleigh and Taylor are independent within the meaning of the NYSE listing standards currently in effect and that Messrs. Tripodo and Bonanno are independent within the meaning of 10A-3 of the Exchange Act. In assessing the independence of our directors, the board of directors considered a number of factors including, for example, with respect to Messrs. Lovoi, Loyd and Raleigh, their affiliation with Roan Holdings, with respect to Messrs. Bonanno, Lederman and Taylor, their prior affiliation with New LINN and with the York Capital funds, the Fir Tree funds and the Elliott funds, respectively, and with respect to Mr. Tripodo, his affiliation with Arch Creek Advisors LLC, which previously provided temporary consulting services to the Company in exchange for fees less than $120,000 in any given year.

Committees of the Board of Directors

We have an audit committee, compensation committee and nominating and corporate governance committee of our board of directors, and may have such other committees as the board of directors shall determine from time to time.

Audit Committee

We have an audit committee consisting of Messrs. Tripodo and Bonanno, with Mr. Tripodo as the Audit Committee s Chairman and audit committee financial expert, as defined by the SEC. Our board of directors has affirmatively determined that each member of our audit committee meets the definition of independent director under the NYSE listing standards and the independence requirements of Rule 10A-3 under the Exchange Act, and that each member of our audit committee is financially literate. On April 15, 2019, Mr. Mills was appointed as the Executive Chairman and began to serve the role of the principal executive officer, in each case, on an interim basis until a successor is appointed. In connection with this appointment, Mr. Mills stepped down from the audit committee and the Company is temporarily deficient of the requirement under Section 303A.07(a) of the NYSE Listed Company Manual. The Company plans to undertake a search for a new independent director.

This committee oversees, reviews, acts on and reports on various auditing and accounting matters to our board of directors, including: the selection of our independent accountants, the scope of our annual audits, fees to be paid to the independent accountants, the performance of our independent accountants and our accounting practices. In addition, the audit committee oversees our compliance programs relating to legal and regulatory requirements. We have adopted an audit committee charter defining the committee s primary duties in a manner consistent with the rules of the SEC and NYSE.

Compensation Committee

We have a compensation committee consisting of Messrs. Lovoi, Lederman and Taylor, with Mr. Taylor as the compensation committee s Chairman. Our board has affirmatively determined that each of Messrs. Lovoi, Lederman and Taylor meets the definition of independent director under the NYSE listing standards and the rules of the SEC.

This committee establishes salaries, incentives and other forms of compensation for officers and other employees. The compensation committee also administers our incentive compensation and benefit plans. We have adopted a compensation committee charter defining the committee s primary duties in a manner consistent with the rules of the SEC, the Public Company Accounting Oversight Board (PCAOB) and NYSE.

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Nominating and Corporate Governance Committee

We have a nominating and corporate governance committee consisting of Messrs. Lederman, Loyd, Raleigh and Tripodo, with Mr. Loyd as the nominating and corporate governance committee s Chairman. Our board has affirmatively determined that each of Messrs. Lederman, Loyd, Raleigh and Tripodo meets the definition of independent director under the NYSE listing standards and the rules of the SEC.

This committee identifies, evaluates and recommends qualified nominees to serve on our board of directors, develop and oversee our internal corporate governance processes and maintain a management succession plan. We have adopted a nominating and corporate governance committee charter defining the committee s primary duties in a manner consistent with the rules of the SEC and applicable stock exchange or market standards.

Compensation Committee Interlocks and Insider Participation

None of our executive officers serve on the board of directors or compensation committee of a company that has an executive officer that serves on our board or compensation committee. No member of our board of directors is an executive officer of a company in which one of our executive officers serves as a member of the board of directors or compensation committee of that company.

Code of Business Conduct and Ethics

We have adopted a Code of Business Conduct and Ethics, which sets forth legal and ethical standards of conduct for all our employees, as well as our directors. We also have adopted a separate code of ethics which applies to our Chief Executive Officer and Senior Financial Officers. All of these documents are available on our website, *www.roanresources.com*, and will be provided free of charge to any shareholder requesting a copy by writing to our Investor Relations Contact, Roan Resources, Inc., 14701 Hertz Quail Springs Pkwy, Oklahoma City, Oklahoma 73134. If any substantive amendments are made to the Code of Ethics for our Chief Executive Officer and Senior Financial Officers or if we grant any waiver, including any implicit waiver, from a provision of such code, we will disclose the nature of such amendment or waiver within four business days on our website. The information on our website is not, and shall not be deemed to be, a part of this filing or incorporated into any other filings we make with the SEC.

Corporate Governance Guidelines

Our board of directors has adopted corporate governance guidelines in accordance with the corporate governance rules of the NYSE. The guidelines will be reviewed regularly by our board of directors in the light of changing circumstances in order to continue serving our best interests and the best interests of our stockholders.

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EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

The Company was not formed until September 19, 2018, and therefore, we did not have executive officers or pay any compensation to officers or employees prior to such date. However, the operations of Roan LLC are being carried on by us following our Reorganization, and the executive officers of Roan LLC are our executive officers since our Reorganization. As such, disclosure regarding our executive officers compensation, including the portion prior to the Reorganization which was established and paid by Roan LLC, is relevant to our stockholders and, accordingly, is disclosed in this Compensation Discussion and Analysis (CD&A) and the executive compensation tables and narrative that follow.

This CD&A describes Roan LLC s practices with regard to the compensation of our named executive officers (our Named Executive Officers) for the fiscal year ended December 31, 2018 (the 2018 Fiscal Year). Our Named Executive Officers for the 2018 Fiscal Year include:

Name	Title
Tony C. Maranto	President and Chief Executive Officer (1)
David M. Edwards	Chief Financial Officer (2)
Greg T. Condray	Executive Vice President Geoscience and Business Development
Joel L. Pettit	Executive Vice President Operations and Marketing
Amber N. Bonney	Vice President and Chief Accounting Officer (3)

(1) Mr. Maranto resigned as President and Chief Executive Officer on April 12, 2019.
(2) Mr. Edwards became our Chief Financial Officer on June 18, 2018.
(3) Ms. Bonney became our Chief Accounting Officer on February 26, 2018; however, she was serving in such capacity through a third party service provider beginning January 25, 2018. On February 9, 2019, Ms. Bonney was appointed as Vice President.

Process for Determining Compensation

Historically, the board of managers of Roan LLC was responsible for oversight of the compensation of our Named Executive Officers, with the objective of attracting talented executives. Input from Mr. Maranto regarding the material components of each Named Executive Officer s (other than Mr. Maranto) employment arrangement was considered by the board of managers of Roan LLC in making compensation determinations with respect to Named Executive Officers other than Mr. Maranto. Following the Reorganization, the Compensation Committee did not make adjustments with respect to the compensation of our Named Executive Officers for the 2018 Fiscal Year, except as discussed below under Elements of Compensation Base Salaries and the determination of 2018 bonuses discussed below under Elements of Compensation Annual Bonuses.

Elements of Compensation

<u>Base Salaries</u>

Each Named Executive Officer s base salary is a fixed component of compensation for performing specific job duties and functions. The base salaries of our Named Executive Officers in effect for the 2018 Fiscal Year were established in connection with the negotiation of each Named Executive Officer s employment agreement at a level the board of managers of Roan LLC determined was necessary to obtain each Named Executive Officer s services. In December 2018, our board implemented a cost of living increase to Ms. Bonney s base salary. The base salary in effect as of December 31, 2018 for each Named Executive Officer is reflected in the table below:

Name	**Base Salary**
Tony C. Maranto	$ 525,000
David M. Edwards	$ 375,000
Greg T. Condray	$ 400,000
Joel L. Pettit	$ 350,000
Amber N. Bonney	$ 248,400

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Annual Bonuses

Each Named Executive Officer is generally eligible to receive an annual bonus each fiscal year. For the 2018 Fiscal Year, the annual bonuses were discretionary. The Compensation Committee determined that the following annual bonuses for our Named Executive Officers were appropriate in light of our operating performance during the 2018 Fiscal Year.

Name	2018 Annual Bonus
Tony C. Maranto	$ 0
David M. Edwards	$ 130,000
Greg T. Condray	$ 140,000
Joel L. Pettit	$ 130,000
Amber N. Bonney	$ 155,000

Long-Term Incentive Compensation

Performance Share Unit Awards

In connection with the commencement of Mr. Edwards s and Ms. Bonney s employment, Roan LLC granted PSU awards to them. The board of managers of Roan LLC determined that it was appropriate to grant these PSU awards in order to incentivize management to focus on growing the total equity value of the Company, provide an incentive for Mr. Edwards and Ms. Bonney to accept their respective offers of employment and provide a retention incentive for them to remain employed by us throughout the performance period. The PSU awards vest based on the extent to which the Company s equity value increases over a three-year performance period commencing on January 1, 2018 and ending December 31, 2020, as set forth in the table below:

Company Equity Value		Percentage of Target Performance Share Units Earned	
Below	$ 3,000,000,000	0%	Below Threshold
	$ 3,000,000,000	25%	
	$ 3,500,000,000	50%	
	$ 4,000,000,000	75%	
	$ 4,500,000,000	100%	Target
	$ 5,000,000,000	125%	
	$ 5,500,000,000	150%	
	$ 6,000,000,000	200%	Maximum

Amended and Restated Management Incentive Plan

In connection with our Reorganization, the MIP was amended, restated and renamed the Roan Resources, Inc. Amended and Restated Management Incentive Plan (the Amended and Restated MIP), and all outstanding PSU awards, including those held by our Named Executive Officers, were adjusted to reflect our Reorganization. Specifically, (i) the number of Target PSUs subject to each PSU award was multiplied by 0.05, (ii) all references to Units in each PSU award agreement were modified to instead refer to shares of Class A common stock such that, to the extent earned, each PSU represents the right to receive one share of Class A common stock rather than one common unit of Roan LLC, (iii) all references to Roan LLC in each PSU award agreement were modified to instead refer to the Company and (iv) all references to the MIP in each PSU award agreement were modified to instead refer to the Amended and Restated MIP.

Other Compensation Elements

Employment Agreements

As described below in Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table, Roan LLC entered into an employment agreement in connection with the commencement of each Named Executive Officer s employment, other than Ms. Bonney.

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Benefit Plans

In 2018, we adopted a 401(k) retirement plan and health and welfare benefit plans in which our Named Executive Officers are eligible to participate. Under the 401(k) retirement plan, we provide for an employer match of employee contributions of up to 6% of eligible compensation and a profit sharing contribution of up to 8% of eligible compensation.

Actions Taken Following Fiscal Year End

In February 2019, our board of directors determined that it was appropriate to increase the base salaries for certain of our Named Executive Officers, as set forth in the table below, to provide a further retention incentive and address certain internal equity considerations. Ms. Bonney s base salary was increased as a result of her promotion to Vice President.

Name	**2018 Base Salary**	**2019 Base Salary**
Tony C. Maranto	$ 525,000	$ 525,000
David M. Edwards	$ 375,000	$ 410,000
Greg T. Condray	$ 400,000	$ 410,000
Joel L. Pettit	$ 350,000	$ 380,000
Amber N. Bonney	$ 248,400	$ 270,000

Other Compensation-Related Matters

Risk Assessment

The Compensation Committee has reviewed our compensation policies as generally applicable to our employees and believes that our policies do not encourage excessive and unnecessary risk-taking, and that the level of risk that they do encourage is not reasonably likely to have a material adverse effect on us. Our management team regularly assesses the risks arising from our compensation policies and practices, and they review and discuss the design features, characteristics, performance metrics and approval mechanisms of total compensation for all employees, including salaries, bonuses, and equity-based compensation awards, to determine whether any of these policies or programs could create risks that are reasonably likely to have a material adverse effect on us.

Accounting and Tax Considerations of Executive Compensation Decisions

The performance share unit awards granted in 2018 were accounted for in accordance with the Financial Accounting Standards Board Accounting Standards Codification Topic 718 (FASB ASC Topic 718), which requires us to estimate the expense of the award over the vesting period applicable to the award.

Section 162(m) of the Internal Revenue Code of 1986, as amended, generally imposes a $1 million limit on the amount of compensation paid to covered employees (as defined in Section 162(m)) that a public corporation may deduct for federal income tax purposes in any year. Compensation paid to certain of our executives could be subject to the $1 million per year deduction limitation imposed by Section 162(m). While we will continue to monitor our compensation programs in light of the deduction limitation imposed by Section 162(m), our Compensation Committee considers it important to retain the flexibility to design compensation programs that are in the best long-term interests of the company and our shareholders. As a result, we have not adopted a policy requiring that all compensation be fully deductible. The Compensation Committee may conclude that paying compensation at levels in excess of the limits under Section 162(m) is nevertheless in the best interests of the company and our shareholders.

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2018 Summary Compensation Table

The table below sets forth the annual compensation earned during the 2018 Fiscal Year by our Named Executive Officers:

Name and Principal Position	Year	Salary ($)(1)	Bonus ($)(2)	Unit Awards ($)(4)	All Other Compensation ($)(5)	Total ($)
Tony C. Maranto	2018	$ 525,000			$ 31,708	$ 556,708
President and Chief Executive Officer	2017	$ 90,865		$ 10,575,000		$ 10,665,865
David M. Edwards	2018	$ 180,289	$ 130,000	$ 2,565,000	$ 19,807	$ 2,895,096
Chief Financial Officer						
Greg T. Condray	2018	$ 400,000	$ 140,000		$ 29,400	$ 569,400
Executive Vice President Geoscience & Business Development	2017	$ 53,846	$ 250,000(3)	$ 3,102,000		$ 3,405,846
Joel L. Pettit	2018	$ 350,000	$ 130,000		$ 57,963	$ 537,963
Executive Vice President Operations and Marketing	2017	$ 53,846		$ 2,820,000		$ 2,873,846
Amber N. Bonney	2018	$ 240,888	$ 155,000	$ 615,000	$ 22,815	$ 1,033,703
Vice President and Chief Accounting Officer						

(1) The amounts in this column represent only the portion of the 2018 Fiscal Year in which each Named Executive Officer was employed with Roan LLC. Mr. Edwards s employment with Roan LLC commenced June 18, 2018; and Ms. Bonney s employment with Roan LLC commenced January 25, 2018. Amounts in this column for the 2018 Fiscal Year for Ms. Bonney also include the amount of fees we paid for services Ms. Bonney provided to us through a third party service provider during January and February 2018 prior to the commencement of her employment with us on February 26, 2018.

(2) The amounts in this column for 2018 represent discretionary annual bonuses paid to our Named Executive Officers in February 2019 for services provided during the 2018 Fiscal Year.

(3) In connection with his appointment as Executive Vice President Geoscience and Business Development, Mr. Condray received a one-time signing bonus of $250,000.

(4) The amounts in this column represent the aggregate grant date fair value of the PSU awards granted to each of our Named Executive Officers, calculated in accordance with FASB ASC Topic 718, disregarding estimated forfeitures. For additional information regarding the assumptions underlying this calculation, please see Note 11 to the historical financial statements, entitled Equity Compensation, which is included in this prospectus. Please see the section of the CD&A above entitled Performance Share Unit Awards and the Grants of Plan-Based Awards Table below for additional information regarding these awards.

(5) Amounts in this column reflect our employer match of 401(k) plan contributions in the 2018 Fiscal Year for each Named Executive Officer. Additionally, for Mr. Pettit, the amount in this column also reflects $34,420 of reimbursements for relocation expenses provided to him in accordance with our relocation reimbursement policy.

Grants of Plan-Based Awards

The table below includes information about PSU awards granted to our Named Executive Officers during the 2018 Fiscal Year, as adjusted to reflect the Reorganization.

		Estimated Future Payouts Under Equity Incentive Plan Awards (1)			
Name	**Grant Date**	**Threshold (#)**	**Target (#)**	**Maximum (#)**	**Grant Date Fair Value of Unit Awards ($)(2)**
Tony C. Maranto					
David M. Edwards	6/18/2018	18,750	75,000	150,000	$ 2,565,000
Greg T. Condray					
Joel L. Pettit					
Amber N. Bonney	2/26/2018	3,750	15,000	30,000	$ 615,000

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(1) Amounts in these columns represent the number of PSU awards granted in 2018 that would vest upon the achievement of a threshold, target, or maximum level of performance, as adjusted to reflect the Reorganization. The actual number of PSU awards that will vest will not be determinable until the close of the performance period on December 31, 2020 and will depend on the Company s equity value at such time.
(2) Amounts in this column represent the grant date fair value of PSU awards granted to our Named Executive Officers in 2018 computed in accordance with FASB ASC 718. For additional information regarding the assumptions underlying this calculation, please see Note 11 to the historical financial statements, entitled Equity Compensation, which is included in this prospectus. Please see the section of the CD&A above entitled Long-Term Incentive Compensation for additional information regarding these awards.

Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table

Roan LLC entered into employment agreements with each of our Named Executive Officers other than Ms. Bonney. Each employment agreement has an initial three-year term that will automatically renew for successive one-year periods until terminated in writing by either party at least 60 days prior to the renewal date. The employment agreements provide for annualized base salaries of at least $525,000 for Mr. Maranto, $375,000 for Mr. Edwards; $400,000 for Mr. Condray; and $350,000 for Mr. Pettit. Additionally, the employment agreements provide each Named Executive Officer with the opportunity to earn an annual bonus for each complete calendar year such Named Executive Officer is employed thereunder, and establishes targets as a percentage of each Named Executive Officer s annualized base salary of 125% for Mr. Maranto, 100% for Messrs. Edwards and Condray, and 75% for Mr. Pettit. Each Named Executive Officer is also eligible to receive annual equity grants and participate in all benefits generally available to similarly situated employees. Additionally, each employment agreement contains certain restrictive covenants applicable to each Named Executive Officer. Pursuant to the terms of the employment agreements, each Named Executive Officer is eligible to severance payments in connection with certain terminations of employment, which are described in more detail below on the section titled Potential Payments Upon Termination or Change in Control.

Outstanding Equity Awards at Fiscal Year-End

The following table reflects information regarding outstanding PSU awards held by our Named Executive Officers as of December 31, 2018.

Name	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)(1)(2)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(3)
Tony C. Maranto(4)	93,750	$ 785,625
David M. Edwards	18,750	$ 157,125
Greg T. Condray	27,500	$ 230,450
Joel L. Pettit	25,000	$ 209,500
Amber N. Bonney	3,750	$ 31,425

(1) Each Named Executive Officer s outstanding PSU awards will become earned over the performance period ending December 31, 2020 depending on the level of achievement of the applicable performance conditions and so long as such Named Executive Officer remains continuously employed with Roan LLC through such date. The number of units reported in this column assumes that the equity value of Roan LLC for the performance period is achieved at the threshold level, which may not be representative of the actual payouts that will occur upon the settlement of the PSU awards, as such actual payouts may be significantly more or less.

(2) To the extent earned, each performance share unit subject to a PSU award represents the right to receive one share of Class A common stock upon vesting. As described above, in connection with our Reorganization, the PSU awards have been adjusted to reflect our Reorganization, including to convert the Roan LLC units subject to the outstanding PSU awards to shares of Class A common stock.

(3) Amounts in this column reflect the market value of the shares of Class A common stock subject to the PSU awards, calculated by multiplying the number of shares reported by $8.38, the closing price of our Class A common shares on December 31, 2018.

(4) Upon his resignation, Mr. Maranto forfeited his outstanding PSUs.

Option Exercises and Stock Vested

No equity awards held by our Named Executive Officers vested during the 2018 Fiscal Year. We have not granted options pursuant to the Amended and Restated MIP since its adoption.

Pension Benefits

We have not maintained, and do not currently maintain, a defined benefit pension plan.

Nonqualified Deferred Compensation

We have not maintained, and do not currently maintain, a nonqualified deferred compensation plan.

Potential Payments Upon Termination or Change in Control

Employment Agreements

As described above in the section entitled Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table, we have entered into employment agreements with each of our Named Executive Officers, other than Ms. Bonney, that provide for severance payments in certain circumstances. We have no agreements with Ms. Bonney that provide for severance or change in control payments. Upon a termination of Messrs. Maranto s, Edwards s, Condray s or Pettit s employment by us without cause or upon such Named Executive Officer s resignation for good reason, such Named Executive Officer is eligible for 24 months worth of base salary payable in 12 equal installments, subject to such Named Executive Officer s execution of a release and continued compliance with the restrictive covenants set forth in such Named Executive Officer s employment agreement. Additionally, each employment agreement provides that annual equity-based awards (excluding the PSU awards described below) will fully accelerate upon the death of the Named Executive Officer (subject to any applicable performance requirements); however, no such annual equity-based awards are currently outstanding.

Under each employment agreement:

cause generally means (a) a material breach by such Named Executive Officer of the employment agreement or any other agreement with Roan LLC, (b) the commission of gross negligence, willful misconduct, breach of fiduciary duty, fraud, theft or embezzlement by such Named Executive Officer, (c) the commission by, conviction or indictment of or plea of nolo contendere by such Named Executive Officer to any felony (or state law equivalent) or any crime involving moral turpitude or (d) such Named Executive Officer s willful failure or refusal to perform his obligations or to follow lawful directives from the board of directors; and

good reason generally means any of the following without such Named Executive Officer s consent: (a) a material diminution in base salary, titles or duties, (b) a material breach by Roan LLC of the employment agreement or any other agreement with such Named Executive Officer or (c) a geographic relocation of such

Named Executive Officer s principal place of employment by more than 50 miles.

Performance Share Unit Awards

Under the award agreement governing the terms of each Named Executive Officer s PSU awards, if a Named Executive Officer s employment with us terminates as a result of (a) a termination by us without cause, (b) such Named Executive Officer s resignation for good reason, or (c) such Named Executive Officer s death or disability, then a pro-rata portion of the PSUs shall become vested based on the number of days which have elapsed from the commencement of the performance period through the date of termination and the achievement of the performance goals for the entire performance. If a termination described in the preceding sentence occurs

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within the one-year period following a change in control, then the performance period shall be deemed to have ended on the date of such change in control, and the PSUs will be settled based on the achievement of the performance goals through the date of such change in control.

As used in the PSU awards, cause and good reason have the meanings described above under Employment Agreements. As used in the PSU awards, disability generally means the inability of our Named Executive Officer to perform the essential functions of his or her position due to physical or mental impairment or other incapacity that continues for more than 120 consecutive days or more than 180 days in any 12-month period. As used in the PSU awards prior to the Reorganization, change in control generally meant the occurrence of any of the following events:

- a change in the ownership of the company, which would occur on the date that any one person, or more than one person acting as a group, acquires ownership of securities in us that, together with securities held by such person or group, constitutes more than 50% of the total fair market value or total voting power of our securities;
- a change in the effective control of the company, which would occur on the date that any one person, or more than one person acting as a group, acquires (or has acquired during the 12-month period ending on the date of the most recent acquisition) ownership of our securities possessing 30% or more of the total voting power of our securities; or
- a change in the ownership of a substantial portion of our assets, which would occur on the date that any one person, or more than one person acting as a group, acquires (or has acquired during the 12-month period ending on the date of the most recent acquisition) assets that have a total gross fair market value equal to or more than 40% of the total gross fair market value of all of our assets immediately prior to such acquisition.

The Reorganization did not constitute a change in control for purposes of the PSU awards.

Following the Reorganization, change in control generally means the occurrence of any of the following events:

- acquisition by any person or group of beneficial ownership of 50% or more of the outstanding shares of Class A common stock or the combined voting power of the outstanding voting securities of Roan Inc.;
- the incumbent directors cease to constitute at least a majority of the board of directors;
- consummation of a business combination unless following such business combination (a) the outstanding Class A common stock or voting securities of Roan Inc. immediately prior to such business combination represent more than 50% of the equity interests or voting power of the entity resulting from the business combination, (b) no person or group beneficially owns 50% or more of the outstanding equity interests or voting power of the entity resulting from the business combination unless such ownership results solely from ownership prior to the business combination, and (c) a majority of the board of directors of the entity resulting from such business combination were incumbent directors prior to the business combination; or

complete liquidation or dissolution of Roan Inc.

The foregoing description is not intended to be a comprehensive summary of the employment agreements or award agreements governing the PSU awards and is qualified in its entirety by reference to such agreements, which are filed as exhibits to the registration statement of which this prospectus forms a part.

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The following table sets forth the payments and benefits that would be received by each Named Executive Officer in the event a termination of employment or a change in control of Roan Inc. had occurred on December 31, 2018, over and above any payments or benefits he otherwise would already have been entitled to or vested in on such date under any employment agreement or other plan of Roan Inc.

Executive	Termination of Employment by Roan LLC Without Cause or by Executive for Good Reason ($)	Termination of Employment due to Death or Disability ($)	Termination of Employment by Roan LLC Without Cause for by Executive for Good Reason following Change in Control ($)(2)	Termination of Employment by Roan LLC for Cause, by Notice of Non-Renewal, or by Executive Without Good Reason ($)
Tony C. Maranto				
Cash Severance	$ 1,050,000		$ 1,050,000	
Accelerated Equity	(1)	(1)	(1)	
Total	**$ 1,050,000**		**$ 1,050,000**	
David M. Edwards				
Cash Severance	$ 750,000		$ 750,000	
Accelerated Equity	(1)	(1)	(1)	
Total	**$ 750,000**		**$ 750,000**	
Greg T. Condray				
Cash Severance	$ 800,000		$ 800,000	
Accelerated Equity	(1)	(1)	(1)	
Total	**$ 800,000**		**$ 800,000**	
Joel L. Pettit				
Cash Severance	$ 700,000		$ 700,000	
Accelerated Equity	(1)	(1)	(1)	
Total	**$ 700,000**		**$ 700,000**	
Amber N. Bonney				
Cash Severance				
Accelerated Equity	(1)	(1)	(1)	
Total				

(1) Because the value of the PSU awards received under the applicable acceleration scenarios described under Performance Share Unit Awards above is based on actual performance through the date specified under Performance Share Unit Awards above, no value is reported for the PSU awards, as performance through the date used for purposes of these calculations was below threshold.

(2) A termination in connection with a change in control must occur within 12 months of the change in control.

CEO Pay Ratio

As required by Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act, and Item 402(u) of Regulation S-K, we are providing the following information about the relationship of the annual total compensation of our employees and the annual total compensation of Tony Maranto, our Chief Executive Officer (our CEO).

For 2018, our last completed fiscal year:

The median of the annual total compensation of all employees of our company (other than the CEO) was $116,400; and

The annual total compensation of our CEO, as reported in the Summary Compensation Table included elsewhere within this prospectus, was $556,708.

Based on this information, for 2018 the ratio of the annual total compensation of our CEO to the median of the annual total compensation of all employees was reasonably estimated to be 5 to 1.

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To identify the median of the annual total compensation of all our employees, as well as to determine the annual total compensation of our median employee and our CEO, we took the following steps:

We determined that, as of December 31, 2018, our employee population consisted of approximately 179 full-time individuals with all of these individuals located in the United States (as reported in Item 1, Business, in our Form 10-K filed with the SEC on April 1, 2019).

We used a consistently applied compensation measure to identify our median employee of comparing the amount of salary or wages by annualizing all new hires to reflect a true calendar year of earnings. We identified our median employee by consistently applying this compensation measure to all of our employees included in our analysis. Since all of our employees, including our CEO, are located in the United States, we did not make any cost of living adjustments in identifying the median employee.

After we identified our median employee, we combined all of the elements of such employee s annualized compensation for the 2018 year in accordance with the requirements of Item 402(c)(2)(x) of Regulation S-K, resulting in annual total compensation of $116,400. The difference between such employee s salary, wages and overtime pay and the employee s annual total compensation represents the estimated annualized 401(k) contributions in the amount of $13,417 that we estimated would have been made on the employee s behalf to our 401(k) plan for the 2018 year.

With respect to the annual total compensation of our CEO, we used the amount reported in the Total column of our 2018 Summary Compensation Table included in this prospectus.

Director Compensation

Prior to the Reorganization, members of the board of managers of Roan LLC did not receive any compensation for their services as directors. In connection with the Reorganization, we adopted a non-employee director compensation policy which provides for payment of the following annual retainers to members of our board who are not officers, employees, paid consultants or advisors of (i) us or our subsidiaries or (ii) investment funds affiliated with or managed by JVL Advisors, LLC, Elliott Management Corporation, Fir Tree Capital Management LP or York Capital Management, L.P.:

$80,000 annual base retainer;

$25,000 supplemental annual retainer for the Lead Independent Director;

$20,000 supplemental annual retainer for the chair of the Audit Committee; and

$10,000 supplemental annual retainer for the members of the Audit Committee and Nominating & Governance Committee.

Pursuant to the policy, our non-employee directors also receive an annual equity award with a value on the date of grant equal to $100,000 based on the closing price of our Class A common stock on the date of grant, rounded to the nearest whole share, and as such, we granted restricted stock unit (RSU) awards on November 5, 2018 to each of Anthony Tripodo and Joseph A. Mills. Additionally, each director is reimbursed for travel and miscellaneous expenses to attend meetings and activities of our board or its committees.

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The table below sets forth the compensation paid to our non-employee directors during the 2018 Fiscal Year.

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)(1)	Total ($)
Anthony Tripodo	$ 36,318	$ 100,005	$ 136,323
Joseph A. Mills	$ 15,489	$ 100,005	$ 115,494

(1) The amounts in this column represent the aggregate grant date fair value of the RSUs granted to Messrs. Tripodo and Mills, calculated in accordance with FASB ASC Topic 718, disregarding estimated forfeitures.

Equity Compensation Plan Information

The following table sets forth information about shares of Class A common stock that may be issued under equity compensation plans as of December 31, 2018.

	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights (1)	(b) Weighted-average exercise price of outstanding options, warrants and rights (2)	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (3)
Equity compensation plans approved by security holders			
Equity compensation plans not approved by security holders	2,329,300		12,924,654
Total	2,329,300		12,924,654

(1) This column reflects the maximum number of Class A common shares subject to PSU awards and the number of Class A common shares subject to RSU awards granted under the Amended and Restated MIP outstanding and unvested as of December 31, 2018. Because the number of units to be issued upon settlement of outstanding PSU awards is subject to performance conditions, the number of units actually issued may be substantially less than the number reflected in this column. No options or warrants have been granted under the Amended and Restated MIP.

(2) No options or warrants have been granted under the Amended and Restated MIP, and the RSU and PSU awards reflected in column (a) are not reflected in this column, as they do not have an exercise price.

(3) This column reflects the total number of Class A common shares remaining available for issuance under the Amended and Restated MIP as of December 31, 2018.

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PRINCIPAL AND SELLING STOCKHOLDERS

The following table sets forth the beneficial ownership of our Class A common stock as of April 17, 2019:

- the selling stockholders;
- each person known to us to beneficially own more than 5% of our outstanding Class A common stock;
- each of our directors;
- our Named Executive Officers; and
- all of our directors and executive officers as a group.

For further information regarding material transactions between us and the selling stockholders, see Certain Relationships and Related Party Transactions.

All information with respect to beneficial ownership has been furnished by the respective 5% or more stockholders, directors or executive officers, as the case may be. Unless otherwise noted, the mailing address of each listed beneficial owner is c/o Roan Resources, Inc., 14701 Hertz Quail Springs Pkwy, Oklahoma City, Oklahoma 73134. The following table is based on 152,539,532 shares of Class A common stock outstanding as of the Effective Date.

	Shares Beneficially Owned(1)		Shares to be Sold Pursuant to this Prospectus		Shares Beneficially Owned After Offering	
Name of Beneficial Owner	**Number**	**%**	**Number**	**%**	**Number**	**%**
Selling Stockholders and 5% Stockholders:						
Roan Holdings(2)	76,269,766	50.0%	76,269,766	50.0%		
Elliott funds (3)	15,794,132	10.4%	15,794,132	10.4%		
Fir Tree funds(4)	14,712,070	9.6%	14,712,070	9.6%		
York Capital funds(5)	9,028,373	5.9%	9,028,373	5.9%		
Directors and Named Executive Officers:						
Tony C. Maranto	20,000	*			20,000	*
Joel L. Pettit						
Greg T. Condray						
Matthew Bonanno						
Evan Lederman						
John V. Lovoi(2)(6)	77,604,936	50.9%	77,604,936	50.9%		
Paul B. Loyd, Jr.(2)	76,269,766	50.0%	76,269,766	50.0%		

Michael P. Raleigh(2)	76,269,766	50.0%	76,269,766	50.0%
Andrew Taylor				
Anthony Tripodo(7)				
Joseph A. Mills(7)				
David M. Edwards				
Amber N. Bonney				
Directors and Executive Officers as a Group (13 Persons)	77,604,936	50.9%	77,604,936	50.9%

* Less than 1%.

(1) The amounts and percentages of Class A common stock beneficially owned are reported on the bases of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a beneficial owner of a security if that person has or shares voting power, which includes the power to vote or direct the voting of such security, or investment power, which includes the power to dispose of or to direct the disposition of such security. Securities that can be so

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acquired are deemed to be outstanding for purposes of computing such person s ownership percentage, but not for purposes of computing any other person s percentage. Under these rules, more than one person may be deemed beneficial owner of the same securities, and a person may be deemed to be a beneficial owner of securities as to which such person has no economic interest. Except as otherwise indicated in these footnotes, each of the beneficial owners has, to our knowledge, sole voting and investment power with respect to the indicated shares of Class A common stock, except to the extent this power may be shared with a spouse.

(2) JVL Advisors, LLC (JVL), indirectly through its investment management arrangements with Asklepios Energy Fund, LP, Hephaestus Energy Fund, LP, Luxiver WI, LP, LVPU, LP, Midenergy Partners II, LP, Navitas Fund, LP, Blackbird 1846 Energy Fund, L.P., Children s Energy Fund, LP, SPQR Energy, LP and Panakeia Energy Fund, LP (collectively, the JVL Funds), beneficially owns an approximate 73.61% interest in Roan Holdings and has the contractual right to nominate a majority of the members of the board of managers of Roan Holdings, which board of managers exercises voting and dispositive power over all securities held by Roan Holdings. The board of managers of Roan Holdings consists of four managers, of which JVL has nominated three, Paul B. Loyd, Jr., Michael P. Raleigh and Kelly Loyd. JVL may be deemed to beneficially own all of the reported securities held by Roan Holdings. Each of the JVL Funds is controlled indirectly by John V. Lovoi. Mr. Lovoi is the sole member of, and exercises investment management control over, JVL. Messrs. Lovoi, Paul Loyd, Raleigh, Kelly Loyd, JVL and the JVL Funds may be deemed to share dispositive power over the securities held by Roan Holdings; thus, they may also be deemed to be the beneficial owners of these securities. Each of Messrs. Lovoi, Paul Loyd, Raleigh, Kelly Loyd, JVL and the JVL Funds disclaims beneficial ownership of the reported securities in excess of such entity s or person s respective pecuniary interest therein. The address for JVL, the JVL Funds and Messrs. Lovoi, Paul Loyd, Raleigh and Kelly Loyd is 10000 Memorial Dr., Suite 550, Houston, Texas 77024.

(3) Consists of (i) 26,513 shares owned by Elliott Associates, L.P. (Elliott Associates), (ii) 5,027,660 shares owned by The Liverpool Limited Partnership (Liverpool) and (iii) 10,739,959 shares owned by Spraberry Investments Inc. (Spraberry, and collectively with Elliott Associates and Liverpool, the Elliott funds). The sole limited partner of Liverpool is Elliott Associates. Spraberry is an indirect subsidiary of Elliott International, L.P. (Elliott LP). Elliott International Capital Advisors Inc. is the investment manager of Elliott LP (Elliott IM) and is regulated by the SEC as an investment advisor. Elliott IM has voting and investment power with respect to the shares held by Spraberry and may be deemed to be the beneficial owner thereof. Each of Elliott Advisors GP LLC, Elliott Capital Advisors, L.P. and Elliott Special GP, LLC, is a general partner of Elliott Associates and is regulated by the SEC as an investment advisor. Each of Elliott Advisors GP LLC, Elliott Capital Advisors, L.P. and Elliott Special GP, LLC has voting and investment power with respect to the shares held by Elliott Associates and may be deemed to be the beneficial owner thereof. There is no single beneficial limited partner of Elliott Associates holding limited partnership interests equal to 10% or more of its total capital. Andrew Taylor, a member of the investment team of Elliott Management Corporation, an affiliate of the Elliott funds, serves on the board of directors of the Company. The address of each of the foregoing entities and Mr. Taylor is c/o Elliott Management Corporation, 40 West 57th Street, New York, New York 10019.

(4) Consists of (i) 548,558 shares owned by Fir Tree Capital Opportunity Master Fund III, L.P., (ii) 1,785,444 shares owned by Fir Tree Capital Opportunity Master Fund, L.P., (iii) 9,968,920 shares owned by Fir Tree E&P Holdings VI, LLC, (iv) 1,150,589 shares owned by FT SOF IV Holdings, LLC, (v) 1,217,275 shares owned by FT SOF V Holdings, LLC and (vi) 41,284 shares owned by FT COF(E) Holdings, LLC (collectively, the Fir Tree funds). Fir Tree Capital Management LP (FTCM) (f/k/a Fir Tree Inc.) is the investment manager for the Fir Tree funds. Jeffrey Tannenbaum, David Sultan and Clinton Biondo control FTCM. Each of FTCM, Messrs. Tannenbaum, Sultan and Biondo has voting and investment power with respect to the shares of Class A common stock owned by the Fir Tree funds and may be deemed to be the beneficial owner of such shares. Evan S. Lederman, a partner of FTCM, serves on the board of directors of the Company. Mr. Lederman does not have voting and investment power with respect to the shares of Class A common stock owned by the Fir Tree funds in his capacity as a partner of FTCM. The address of each of the foregoing entities and Messrs. Tannenbaum,

Sultan, Biondo and Lederman is c/o Fir Tree Capital Management LP, 55 West 46th Street, 29th Floor, New York, New York 10036.

(5) Consists of (i) 1,329,972 shares owned by York Capital Management, L.P., (ii) 3,088,432 shares owned by York Credit Opportunities Investments Master Fund, L.P., (iii) 2,424,480 shares owned by York Credit Opportunities Fund, L.P., (iv) 1,850,097 shares owned by York Multi-Strategy Master Fund, L.P., (v) 135,392 shares owned by Exuma Capital, L.P., and (vi) 200,000 shares owned by York Select Strategy Master Fund, L.P. (collectively, the York Capital funds). York Capital Management Global Advisors, LLC (YCMGA) is the senior managing member of the general partner of each of the York Capital funds. James G. Dinan is the chairman of, and controls, YCMGA. Each of YCMGA and Mr. Dinan has voting and investment power with respect to the shares owned by each of the York Capital funds and may be deemed to be beneficial owners thereof. Each of YCMGA and Mr. Dinan disclaim beneficial ownership of such shares except to the extent of their pecuniary interests therein. Matthew W. Bonanno, a partner of YCMGA, serves on the board of directors of the Company. The address of the York Capital funds, Mr. Dinan and Mr. Bonanno is 767 Fifth Avenue, 17th Floor, New York, New York 10153.

(6) Consists of (i) 76,269,766 shares owned by Roan Holdings and (ii) 1,335,170 shares owned by various entities (the Lovoi Entities) controlled indirectly by Mr. Lovoi through JVL. Mr. Lovoi is the sole member of, and exercises investment management control over, JVL. Through JVL, Mr. Lovoi exercises voting and dispositive power over all securities held by the Lovoi Entities and may be deemed to be the beneficial owner thereof. Each of Mr. Lovoi, JVL and the Lovoi Entities disclaims beneficial ownership of the reported securities in excess of such entity s or person s respective pecuniary interest therein. Please see footnote (2) for additional information regarding the shares owned by Roan Holdings. The address for Mr. Lovoi, JVL and the Lovoi Entities is 10000 Memorial Dr., Suite 550, Houston, Texas 77024.

(7) Pursuant to the Stockholders Agreement, Messrs. Tripodo and Mills were designated to the board of directors by Roan Holdings.

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REORGANIZATION

We were incorporated under the laws of the State of Delaware in September 2018, for the purpose of facilitating a reorganization and to become a holding company of Roan LLC. Our only assets are equity interests in our subsidiaries. Prior to the reorganization, we had not engaged in any business or other activities except in connection with our formation and we had no previous operations, assets or liabilities.

Roan LLC, our predecessor, was formed as a Delaware limited liability company in May 2017 as joint venture between Old Linn and Citizen and began operations in August 2017, upon the close of the Contribution. 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:

(i) on July 25, 2018, Old Linn merged with and into Linn Merger Sub #1, LLC (Riviera Merger Sub), a wholly owned subsidiary of New Linn, with Riviera Merger Sub surviving such merger, and all outstanding shares of Class A common stock of Old Linn were automatically converted into shares of Class A common stock of New Linn on a one-for-one basis;

(ii) on July 25, 2018, New Linn caused certain of its subsidiaries to effect a distribution of its indirect 50% equity interest in Roan LLC to be held directly by New Linn;

(iii) on August 7, 2018, New Linn contributed to its wholly owned subsidiary, Riviera, all of the membership interests in Riviera Merger Sub; and

(iv) on August 7, 2018, New Linn completed the spin-off of Riviera by distributing to the Legacy Linn Stockholders all of the issued and outstanding common stock of Riviera on a pro rata basis.

The above transactions are collectively referred to as the Riviera Separation. As a result of the Riviera Separation, Riviera held, directly or through its subsidiaries, substantially all of the assets of New Linn, other than New Linn s 50% equity interest in Roan LLC.

Following the Riviera Separation, New Linn and Roan Holdings reorganized their ownership of Roan LLC through the creation of certain new entities and the consummation of additional restructuring transactions. On the Effective Date, we consummated a reorganization transaction pursuant to the Master Reorganization Agreement by and among New Linn, Roan Holdings and Roan LLC. In connection with the Master Reorganization Agreement, we entered into the following agreements on the Effective Date:

- a merger agreement (the Linn Merger Agreement) with New Linn and Linn Merger Sub #2, LLC (Linn Merger Sub), pursuant to which Linn Merger Sub merged with and into New Linn, with New Linn surviving the merger as the Company s wholly owned direct subsidiary, and the Legacy Linn Stockholders receiving an aggregate of 76,269,766 shares of our Class A common stock as merger consideration (the Linn Merger); and

a merger agreement (the Roan Holdco Merger Agreement and, together with the Linn Merger Agreement, the Merger Agreements) with Roan Holdings, Roan Holdco and Linn Merger Sub #3, LLC (Holdco Merger Sub , pursuant to which, immediately after the Linn Merger, Holdco Merger Sub merged with and into Roan Holdco, with Roan Holdco surviving the merger as the Company s wholly owned direct subsidiary, and Roan Holdings, the sole member of Roan Holdco, receiving an aggregate of 76,269,766 shares of our Class A common stock as merger consideration (the Holdco Merger).

We refer to the Linn Merger, the Holdco Merger and the other transactions contemplated by the Merger Agreements and Master Reorganization Agreement as the Reorganization. On September 27, 2018, we amended and restated our certificate of incorporation and bylaws pursuant to the terms of the Master Reorganization Agreement and the Voting Agreement (as defined herein). The following diagram indicates our simplified ownership structure as of September 24, 2018, immediately following the closing of the Reorganization:

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CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Historical Transactions with Affiliates

Contribution Agreement and Management Services Agreements

On August 31, 2017, we entered into the contribution agreement with Citizen and Old Linn, pursuant to which, among other things, Citizen and Old Linn contributed oil and natural gas properties within an area-of-mutual-interest to us, in exchange for which each received a 50% equity interest in us.

In conjunction with the contribution agreement, the Company entered into MSAs with both Citizen and Old Linn. Under the MSAs, Citizen and Old Linn provided certain services in respect to the oil and natural gas properties they contributed to the Company. Such services included serving as operator of the oil and natural gas properties contributed, land administration, marketing, information technology and accounting services. As a result of Citizen and Old Linn continuing to serve as operator of the contributed assets and contracting directly with vendors for goods and services for operations, Citizen and Old Linn collected amounts due from joint interest owners for their share of costs and billed the Company for its share of costs. The services provided under the MSAs ended in April 2018 when the Company took over as operator for the oil and natural gas properties contributed by Citizen and Old Linn. For the year ended December 31, 2018, the Company incurred approximately $10.0 million in charges related to the services provided under the MSAs.

Through April 2018, Citizen and Old Linn billed the Company for its share of operating costs in accordance with the MSAs. At December 31, 2017, the Company had $55.5 million and $46.5 million due to Old Linn and Citizen, respectively. At December 31, 2017, the Company had $19.0 million due to Old Linn and Citizen for revenue suspense associated with the oil and gas properties contributed to the Company.

In conjunction with the conclusion of the MSAs, the Company assumed certain working capital accounts, totaling $112.6 million, associated with the properties contributed from Citizen and Old Linn.

Citizen Energy II, LLC

Atlas, LLC (Atlas) provided us supervisory services throughout drilling and completion operations. Atlas is jointly owned by a director and an employee of Citizen. For the year ended December 31, 2017, we incurred $2.3 million in charges related to services provided by Atlas.

Jones Energy, Inc.

In May 2018, Roan LLC elected to participate with its interest in a Jones Energy, Inc. well in Canadian County, Oklahoma, and, in connection, Roan LLC has paid Jones Energy, Inc. a total of $0.7 million during the year ended December 31, 2018. As of December 31, 2018, JVL, an affiliate of our significant stockholder, Roan Holdings, held 16.34% of the combined voting power of Jones Energy, Inc. Messrs. Lovoi and Loyd were members of the board of directors of Jones Energy, Inc. until September 2018 and Mr. Lovoi is the sole member of, and exercises investment management control over JVL.

Riviera Resources, Inc.

Messrs. Taylor, Lederman and Bonanno are on our board of directors and the board of directors of Riviera. Additionally, certain of our principal stockholders are also significant stockholders in Riviera.

Natural Gas Dedication Agreement. The Company has a natural gas dedication agreement with Blue Mountain Midstream LLC (Blue Mountain), which is a subsidiary of Riviera. Sales to Blue Mountain during the year ended December 31, 2017 are reflected as natural gas sales affiliates and natural gas liquids sales affiliates in the accompanying statements of operations. Sales to Blue Mountain during the year ended December 31, 2018 were approximately $66 million.

Water Management Services Agreement. In January 2019, the Company entered into a water management services agreement with Blue Mountain. Under this agreement, Blue Mountain will provide water management services including pipeline gathering, disposal, treatment and redelivery of recycled water. The agreement provides for an acreage dedication for water management services through January 2029.

Transition Services Agreement. On August 7, 2018, New Linn entered into a Transition Services Agreement (the Riviera TSA) with Riviera to facilitate an orderly transition following the Riviera Separation. During the term of the Riviera TSA, Riviera provided New Linn with certain finance, financial reporting, information technology, investor relations, legal, payroll, tax and other services. Riviera reimbursed New Linn for, or paid on New Linn s behalf, all direct and indirect costs and expenses incurred by New Linn during the term of the Riviera TSA in connection with the fees for any such services. The Riviera TSA terminated according to its terms on the Effective Date.

Riviera Separation and Distribution Agreement. On August 7, 2018, the Company s predecessor, New Linn, entered into that certain Separation and Distribution Agreement by and between New Linn and Riviera, following which Riviera holds, directly or through its subsidiaries, substantially all of the assets of Old Linn, other than Old Linn s 50% equity interest in Roan LLC. Following the internal reorganization, New Linn distributed all of the outstanding shares of common stock of Riviera to the Legacy Linn Stockholders on a pro rata basis, including the Elliott Funds, the Fir Tree Funds and the York Capital Funds, each a principal stockholder of the Company. On September 21, 2018, the Elliott Funds, the Fir Tree Funds and the York Capital Funds owned approximately 20.8%, 19.4% and 12.1%, respectively, of Riviera. Immediately following the Riviera Separation, Riviera s common stock closed at $23.25 per share, valuing the stock received by each of the Elliott Funds, the Fir Tree Funds and the York Capital Funds at approximately $367.2 million, $342.1 million and $197.1 million, respectively.

Tax Matters Agreement. In conjunction with the Reorganization, the Company s predecessor, New Linn, entered into a tax matters agreement with Riviera (the Riviera TMA). The Riviera TMA, in part, provides for indemnification of the Company and entitlement of refunds by Riviera of certain taxes related to New Linn prior to the spinoff of assets from New Linn to Riviera. As a result of the Riviera TMA and an estimated overpayment of federal taxes by New Linn, the Company has recorded a payable of $7.6 million to Riviera at December 31, 2018.

Corporate Office Lease. During 2018, we entered into a lease for office space in Oklahoma City, Oklahoma that is owned by a subsidiary of Riviera. The lease has an initial term of five years. Under this lease, we paid $0.5 million during the year ended December 31, 2018 and total remaining payments are $8.1 million.

Legal expenses. During the year ended December 31, 2018, we also reimbursed Riviera $1.8 million for legal services incurred on the behalf of Roan in connection with the Reorganization.

Stockholders Agreement

In connection with the Reorganization, on the Effective Date, we entered into a stockholders agreement (the Stockholders Agreement) with Roan Holdings and the Elliot funds, the Fir Tree funds and the York Capital funds (each such group of affiliated funds, a Principal Linn Stockholder, and together with Roan Holdings, the principal stockholders), which will govern certain rights and obligations of the principal stockholders following the Reorganization.

Pursuant to the Stockholders Agreement, until the earlier of (i) our 2020 annual general meeting of stockholders (the 2020 annual meeting) and (ii) with respect to the applicable Principal Linn Stockholder, the date on which the applicable Principal Linn Stockholder ceases to beneficially own at least 5% of our outstanding shares of Class A common stock, each Principal Linn Stockholder shall have the right to designate one director (each, a Linn

Stockholder Director) to our board of directors and to fill any vacancy on the board of directors due to the death, disability, resignation or removal of any Linn Stockholder Director designated by such principal Linn Stockholder; provided, however, that at all times, at least one Linn Stockholder Director shall be an independent director who meets the independence standards of any national securities exchange on which our Class A common stock is or will be listed and Rule 10A-3 of the Exchange Act. If a Principal Linn Stockholder s

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designation rights terminate as a result of no longer beneficially owning at least 5% of our outstanding shares of Class A common stock, the applicable Linn Stockholder Director shall be entitled to continue serving on the board of directors until the end of such Linn Stockholder Director s term.

The Stockholders Agreement also provides that until the earlier of (i) the 2020 annual meeting and (ii) the date on which Roan Holdings ceases to beneficially own at least 5% of the outstanding shares of Class A common stock, Roan Holdings shall have the right to designate one independent director (the Roan Holdings Independent Director) to the board of directors (subject to the consent of the Principal Linn Stockholders) and to fill any vacancy on the board of directors due to the death, disability, resignation or removal of any Roan Holdings Independent Director.

In addition, the Stockholders Agreement provides that until the earlier of (i) the 2020 annual meeting and (ii) the date on which Roan Holdings ceases to beneficially own at least 5% of the outstanding shares of Class A common stock, Roan Holdings shall have the right to designate to the board of directors a number of directors (each, a Roan Holdings Director) equal to: (i) if Roan Holdings beneficially owns at least 30% of the outstanding shares of Class A common stock, four directors; (ii) if Roan Holdings beneficially owns at least 15% but less than 30% of the outstanding shares of Class A common stock, three directors; and (iii) if Roan Holdings beneficially owns at least 5% but less than 15% of the outstanding shares of Class A common stock, two directors, and, in each case, to fill any vacancy on the board of directors due to the death, disability, resignation or removal of any Roan Holdings Director; provided, however, that at all times, at least one Roan Holdings Director shall be an independent director. If Roan Holdings designation rights terminate as a result of no longer beneficially owning at least 5% of our outstanding shares of Class A common stock, the Roan Holdings Directors shall be entitled to continue serving on the board of directors until the end of such Roan Holdings Directors terms.

Additionally, pursuant to the Stockholders Agreement we have agreed, to the fullest extent permitted by applicable law (including with respect to any applicable fiduciary duties under Delaware law), to take all necessary action to effectuate the above by: (i) including the persons designated pursuant to the Stockholders Agreement in the slate of nominees recommended by the board of directors for election at any meeting of stockholders called for the purpose of electing directors, (ii) nominating and recommending each such individual to be elected as a director as provided herein, (iii) soliciting proxies or consents in favor thereof, and (iv) without limiting the foregoing, otherwise using its reasonable best efforts to cause such nominees to be elected to the board of directors, including providing at least as high a level of support for the election of such nominees as it provides to any other individual standing for election as a director.

Roan LLC Agreement

On the Effective Date, in connection with the Reorganization, New Linn and Roan Holdco amended and restated the limited liability company agreement of Roan LLC to cause Roan LLC to be a manager-managed limited liability company, with Roan Inc. serving as the sole manager.

Registration Rights Agreement

On the Effective Date, in connection with the Reorganization, we entered into a Registration Rights Agreement (the Registration Rights Agreement) with certain significant holders of our Class A common stock identified on the signature pages thereto (the Holders).

Pursuant to, and subject to the limitations set forth in, the Registration Rights Agreement, we agreed, no later than thirty (30) days following the Reorganization, to register under federal securities laws the public offer and resale of the shares of Class A common stock held by the Holders or certain of their affiliates or permitted transferees on a shelf registration statement.

In addition, pursuant to the Registration Rights Agreement, certain of the Holders have the right to require us, subject to certain limitations set forth therein, to effect a distribution of any or all of their shares of Class A common stock by means of an underwritten offering. Further, subject to certain exceptions, if at any time we propose to register an offering of its equity securities or conduct an underwritten offering, whether or not for our own account, then we must notify the Holders of such proposal reasonably in advance of the anticipated filing date or commencement of the underwritten offering, as applicable, to allow them to include a specified number of their shares in that registration statement or underwritten offering, as applicable.

These registration rights are subject to certain conditions and limitations, including our right to limit the number of shares to be included in a registration statement or underwritten offering and our right to delay or withdraw a registration statement under certain circumstances. We will generally pay all registration expenses in connection with our obligations under the Registration Rights Agreement other than underwriting discounts and commissions related to the shares sold by the selling stockholders, regardless of whether a registration statement is filed or becomes effective.

We are generally required to maintain the effectiveness of the shelf registration statement with respect to any Holder until the date on which there are no longer any Registrable Securities (as defined in the Registration Rights Agreement) outstanding.

Pursuant to the Registration Rights Agreement, certain of the Holders agreed, for a period of 90 days from the Effective Date, not to (i) sell, transfer or otherwise dispose of any shares of Class A common stock or publicly disclose the intention to make any offer, sale or disposition, or (ii) make any demand for or exercise any right with respect to the registration of any shares of Class A common stock other than (A) in connection with an underwritten offering pursuant to the terms of the Registration Rights Agreement, (B) in connection with the filing of any registration statement effected pursuant to the terms of the Registration Rights Agreement, (C) sales, transfers and dispositions of shares of Class A common stock up to an aggregate of 10% of the Class A common stock outstanding on the Effective Date and (D) distributions of shares of Class A common stock to members, partners or stockholders of such Holders.

Voting Agreement

Following the Linn Merger and the Holdco Merger, on the Effective Date, in connection with the Reorganization, we entered into a voting agreement (the Voting Agreement) with the principal stockholders. Pursuant to the terms of the Voting Agreement, on September 27, 2018, the principal stockholders voted all of their outstanding shares of our Class A common stock in favor of the adoption and approval of our second amended and restated certificate of incorporation, our second amended and restated bylaws, the amended and restated certificate of incorporation of New Linn and the second amended and restated bylaws of New Linn, and such documents were adopted and approved, effective as of the September 27, 2018.

Master Reorganization Agreement

On the Effective Date, we consummated the Master Reorganization Agreement by and among New Linn, Roan Holdings and Roan LLC. In connection with the Master Reorganization Agreement, we entered into the following agreements on the Effective Date:

the Linn Merger Agreement with New Linn and Linn Merger Sub, pursuant to which the Linn Merger occurred; and

the Roan Holdco Merger Agreement with Roan Holdings, Roan Holdco and Holdco Merger Sub, pursuant to which, immediately after the Linn Merger, the Holdco Merger occurred.

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The Linn Merger was effected pursuant to Section 251(g) of the Delaware General Corporation Law, which provides for the formation of a holding company without a vote of the stockholders of the constituent corporations.

Procedures for Approval of Related Party Transactions

A Related Party Transaction is a transaction, arrangement or relationship in which we or any of our subsidiaries was, is or will be a participant, the amount of which involved exceeds $120,000, and in which any Related Person had, has or will have a direct or indirect material interest. A Related Person means:

- any person who is, or at any time during the applicable period was, one of our executive officers or one of our directors;
- any person who is known by us to be the beneficial owner of more than 5% of our Class A common stock;
- any immediate family member of any of the foregoing persons, which means any child, stepchild, parent, stepparent, spouse, sibling, mother-in-law, father-in-law, son-in-law, daughter-in-law, brother-in-law or sister-in-law of a director, executive officer or a beneficial owner of more than 5% of our Class A common stock, and any person (other than a tenant or employee) sharing the household of such director, executive officer or beneficial owner of more than 5% of our Class A common stock; and
- any firm, corporation or other entity in which any of the foregoing persons is a partner or principal or in a similar position or in which such person has a 10% or greater beneficial ownership interest.

Our board of directors adopted a written related party transactions policy. Pursuant to this policy, our audit committee will review all material facts of all future Related Party Transactions and either approve or disapprove entry into the Related Party Transaction, subject to certain limited exceptions. In determining whether to approve or disapprove entry into a Related Party Transaction, our audit committee shall take into account, among other factors, the following: (i) whether the Related Party Transaction is on terms no less favorable than terms generally available to an unaffiliated third-party under the same or similar circumstances; and (ii) the extent of the Related Person s interest in the transaction. Further, the policy will require that all Related Party Transactions required to be disclosed in our filings with the SEC be so disclosed in accordance with applicable laws, rules and regulations.

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DESCRIPTION OF CAPITAL STOCK

The authorized capital stock of Roan Resources, Inc. consists of 800,000,000 shares of Class A common stock, $0.001 par value per share, of which 152,539,532 shares are issued and outstanding and 50,000,000 shares of preferred stock, $0.001 par value per share, of which no shares are issued and outstanding.

The following summary of the capital stock and our second amended and restated certificate of incorporation and second amended and restated bylaws does not purport to be complete and is qualified in its entirety by reference to the provisions of applicable law and to our second amended and restated certificate of incorporation and second amended and restated bylaws, which are filed as exhibits to the registration statement of which this prospectus forms a part.

Description of Class A Common Stock

Except as provided by law or in a preferred stock designation, holders of Class A common stock are entitled to one vote for each share held of record on all matters submitted to a vote of the stockholders, will have the exclusive right to vote for the election of directors and do not have cumulative voting rights. Except as otherwise required by law, holders of Class A common stock are not entitled to vote on any amendment to the second amended and restated certificate of incorporation (including any certificate of designations relating to any series of preferred stock) that relates solely to the terms of any outstanding series of preferred stock if the holders of such affected series are entitled, either separately or together with the holders of one or more other such series, to vote thereon pursuant to our second amended and restated certificate of incorporation (including any certificate of designations relating to any series of preferred stock) or pursuant to the DGCL. Subject to prior rights and preferences that may be applicable to any outstanding shares or series of preferred stock, holders of Class A common stock are entitled to receive ratably in proportion to the shares of Class A common stock held by them such dividends (payable in cash, stock or otherwise), if any, as may be declared from time to time by our board of directors out of funds legally available for dividend payments. All outstanding shares of Class A common stock are fully paid and non-assessable.

The holders of Class A common stock have no preferences or rights of conversion, exchange, pre-emption or other subscription rights. There are no redemption or sinking fund provisions applicable to Class A common stock. In the event of any voluntary or involuntary liquidation, dissolution or winding-up of our affairs, holders of Class A common stock will be entitled to share ratably in our assets in proportion to the shares of Class A common stock held by them that are remaining after payment or provision for payment of all of our debts and obligations and after distribution in full of preferential amounts to be distributed to holders of outstanding shares of preferred stock, if any.

Description of Preferred Stock

Our second amended and restated certificate of incorporation authorizes our board of directors, subject to any limitations prescribed by law, without further stockholder approval, to establish and to issue from time to time one or more classes or series of preferred stock, par value $0.001 per share, covering up to an aggregate of 50,000,000 shares of preferred stock. Each class or series of preferred stock will cover the number of shares and will have the powers, preferences, rights, qualifications, limitations and restrictions determined by the board of directors, which may include, among others, dividend rights, liquidation preferences, voting rights, conversion rights, preemptive rights and redemption rights. Except as provided by law or in a preferred stock designation, the holders of preferred stock will not be entitled to vote at or receive notice of any meeting of stockholders.

Anti-Takeover Effects of Provisions of Our Second Amended and Restated Certificate of Incorporation, Our Second Amended and Restated Bylaws and Delaware Law

Some provisions of Delaware law, our second amended and restated certificate of incorporation and our second amended and restated bylaws contain provisions that could make the following transactions more difficult: acquisitions of us by means of a tender offer, a proxy contest or otherwise or removal of our incumbent officers and directors. These provisions may also have the effect of preventing changes in our management. It is possible that these provisions could make it more difficult to accomplish or could deter transactions that stockholders may otherwise consider to be in their best interest or in our best interests, including transactions that might result in a premium over the market price for our shares.

These provisions are expected to discourage coercive takeover practices and inadequate takeover bids. These provisions are also designed to encourage persons seeking to acquire control of us to first negotiate with us. We believe that the benefits of increased protection and our potential ability to negotiate with the proponent of an unfriendly or unsolicited proposal to acquire or restructure us outweigh the disadvantages of discouraging these proposals because, among other things, negotiation of these proposals could result in an improvement of their terms.

Delaware Law

Section 203 of the DGCL prohibits a Delaware corporation, including those whose securities are listed for trading on the NYSE, from engaging in any business combination with any interested stockholder for a period of three years following the date that the stockholder became an interested stockholder, unless:

- the transaction is approved by the board of directors before the date the interested stockholder attained that status;
- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced; or
- on or after such time the business combination is approved by the board of directors and authorized at a meeting of stockholders by at least two-thirds of the outstanding voting stock that is not owned by the interested stockholder.

We will continue to elect to not be subject to the provisions of Section 203 of the DGCL.

Our Second Amended and Restated Certificate of Incorporation and Our Second Amended and Restated Bylaws

Provisions of our second amended and restated certificate of incorporation and our second amended and restated bylaws may delay or discourage transactions involving an actual or potential change in control or change in our management, including transactions in which stockholders might otherwise receive a premium for their shares, or transactions that our stockholders might otherwise deem to be in their best interests. Therefore, these provisions could adversely affect the price of our Class A common stock.

Among other things, our second amended and restated certificate of incorporation and second amended and restated bylaws:

establish advance notice procedures with regard to stockholder proposals relating to the nomination of candidates for election as directors or new business to be brought before meetings of our stockholders. These procedures provide that notice of stockholder proposals must be timely given in writing to our corporate secretary prior to the meeting at which the action is to be taken. Generally, to be timely, notice must be received at our principal executive offices not less than 90 days nor more than 120 days prior to the first anniversary date of the annual meeting for the preceding year. Our second amended and restated bylaws will specify the requirements as to form and content of all stockholders notices. These requirements may preclude stockholders from bringing matters before the stockholders at an annual or special meeting;

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provide our board of directors the ability to authorize undesignated preferred stock. This ability makes it possible for our board of directors to issue, without stockholder approval, preferred stock with voting or other rights or preferences that could impede the success of any attempt to change control of us. These and other provisions may have the effect of deferring hostile takeovers or delaying changes in control or management of our company;

provide that the authorized number of directors may be changed only by resolution of the board of directors;

on or after the 2020 annual meeting, provide that all vacancies, including newly created directorships, may, except as otherwise required by law or, if applicable, the rights of holders of a series of preferred stock, be filled by the affirmative vote of a majority of directors then in office, even if less than a quorum, or, prior to the 2020 annual meeting, by certain principal stockholders, for so long as such principal stockholders and their affiliates collectively beneficially own a certain amount of the outstanding shares of our Class A common stock;

provide for our board of directors to be divided into two classes of directors, with the first class serving a term ending on the date of the Company s 2019 annual general meeting of stockholders and the second class serving a term ending on the date of the 2020 annual meeting. Following the 2020 annual meeting, the board of directors will cease to be classified. This system of electing and removing directors may tend to discourage a third party from making a tender offer or otherwise attempting to obtain control of us, because it generally makes it more difficult for stockholders to replace a majority of the directors;

provide that special meetings of our stockholders may only be called by the board of directors;

provide that any action required or permitted to be taken by the stockholders must be effected at a duly called annual or special meeting of stockholders and may not be effected by any consent in writing in lieu of a meeting of such stockholders, subject to the rights of the holders of any series of preferred stock with respect to such series;

provide that the affirmative vote of the holders of a majority of the voting power of all then outstanding Class A common stock entitled to vote generally in the election of directors shall be required to remove any or all of the directors from office with or without cause; and

at any time prior to the 2020 annual meeting,

or until the applicable Principal Linn Stockholder ceases to beneficially own at least 5% of our outstanding shares of Class A common stock, each Principal Linn Stockholder shall have the right to designate one director to our board of directors and to fill any vacancy on the board of directors due to the death, disability, resignation or removal of such Linn Stockholder Director designated by such Principal Linn Stockholder;

or until the Roan Holdings ceases to beneficially own at least 5% of the outstanding shares of Class A common stock, Roan Holdings shall have the right to designate one independent director to the board of directors (subject to the consent of the Principal Linn Stockholders) and to fill any vacancy on the board of directors due to the death, disability, resignation or removal of such Roan Holdings Independent Director;

or until the Roan Holdings ceases to beneficially own at least 5% of the outstanding shares of Class A common stock, Roan Holdings shall have the right to designate to the board of directors a number of directors equal to: (i) if Roan Holdings beneficially owns at least 30% of the outstanding shares of Class A common stock, four directors; (ii) if Roan Holdings beneficially owns at least 15% but less than 30% of the outstanding shares of Class A common stock, three directors; and (iii) if Roan Holdings beneficially owns at least 5% but less than 15% of the outstanding shares of Class A common stock, two directors, and, in each case, to fill any vacancy on the board of directors due to the death, disability, resignation or removal of any such Roan Holdings Director; and provide that the then-current chief executive officer of Roan Inc. be designated to serve as a member of the board of directors.

Amendment of the Second Amended and Restated Bylaws

The second amended and restated certificate of incorporation and the second amended and restated bylaws grant to the board of directors the power to adopt, amend, restate or repeal the second amended and restated bylaws, as permitted under the DGCL, provided that any adoption, alternation or repeal by the board of directors shall require (i) prior to the date of the 2020 annual meeting, a vote of equal to or great than 66 2/3% of the board of directors, and (ii) on and after the date of the 2020 annual meeting, only by a vote of a majority of the board of directors. The stockholders may adopt, amend, restate or repeal the second amended and restated bylaws, subject to the then-applicable terms and conditions of the Stockholders Agreement, but only by a vote of holders of at least 66 2/3% in voting power of the outstanding shares of stock entitled to vote thereon, voting together as a single class in addition to any approval required by law, the Bylaws or the terms of any preferred stock. Any amendment or waiver of any provision of the Bylaws that adversely affects the rights, preferences or privileges of the holders of the Preferred Stock in any material respect requires the affirmative vote of a majority of the outstanding shares of Preferred Stock outstanding as of the initial issuance.

Corporate Opportunity

Under our second amended and restated certificate of incorporation, to the extent permitted by law:

- our principal stockholders and each of their respective affiliates (including portfolio investments of any of them) have the right to, and have no duty to abstain from exercising such right to, conduct business with any business that is competitive or in the same line of business as us, do business with any of our clients or customers, or invest or own any interest publicly or privately in, or develop a business relationship with, any business that is competitive or in the same line of business as us;

- if our principal stockholders or any of their respective affiliates (including portfolio investments of any of them) acquire knowledge of a potential transaction that could be a corporate opportunity, they have no duty to offer such corporate opportunity to us; and

- we have renounced any interest or expectancy in, or in being offered an opportunity to participate in, such corporate opportunities.

Forum Selection

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:

- any derivative action or proceeding brought on our behalf;

- 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;
- any action asserting a claim against us arising pursuant to any provision of the DGCL, our second amended and restated certificate of incorporation or our second amended and restated bylaws; or
- 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.

The forum selection clause is intended to apply to the fullest extent permitted by applicable law to the above-specified types of actions and proceedings, including to the extent permitted by the federal securities laws to lawsuits asserting both the above-specified claims and federal securities claims. However, application of the forum selection clause may in some instances be limited by applicable law. Thus, whether the forum selection clause will apply to any particular action, including actions arising under the federal securities laws,

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requires a case-by-case analysis. Our amended and restated certificate of incorporation also provides that any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock will be deemed to have notice of, and to have consented to, this forum selection provision. Although we believe these provisions will benefit us by providing increased consistency in the application of Delaware law for the specified types of actions and proceedings, the provisions may have the effect of discouraging lawsuits against our directors, officers, employees and agents. The enforceability of similar exclusive forum provisions in other companies certificates of incorporation has been challenged in legal proceedings, and it is possible that, in connection with one or more actions or proceedings described above, a court could rule that this provision in our second amended and restated certificate of incorporation is inapplicable or unenforceable, including with respect to claims arising under the federal securities laws. Stockholders will not be deemed, by operation of the forum selection clause alone, to have waived claims arising under the federal securities laws and the rules and regulations thereunder.

Limitation of Liability and Indemnification Matters

Our second amended and restated certificate of incorporation limits the liability of our directors for monetary damages for breach of their fiduciary duty as directors, except for liability that cannot be eliminated under the DGCL. Delaware law provides that directors of a company will not be personally liable for monetary damages for breach of their fiduciary duty as directors, except for liabilities:

- for any breach of their duty of loyalty to us or our stockholders;
- for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law;
- for unlawful payment of dividend or unlawful stock repurchase or redemption, as provided under Section 174 of the DGCL; or
- for any transaction from which the director derived an improper personal benefit.

Any amendment, repeal or modification of these provisions will be prospective only and would not affect any limitation on liability of a director for acts or omissions that occurred prior to any such amendment, repeal or modification.

Our second amended and restated bylaws also provide that we will indemnify our directors and officers to the fullest extent permitted by Delaware law. Our second amended and restated bylaws also will permit us to purchase insurance on behalf of any officer, director, employee or other agent for any liability arising out of that person s actions as our officer, director, employee or agent, regardless of whether Delaware law would permit indemnification. We have entered into indemnification agreements with each of our current directors. These agreements will require us to indemnify these individuals to the fullest extent permitted under Delaware law against liability that may arise by reason of their service to us, and to advance expenses incurred as a result of any proceeding against them as to which they could be indemnified. We believe that the limitation of liability provision that will be in our second amended and restated certificate of incorporation and the indemnification agreements will facilitate our ability to continue to attract and retain qualified individuals to serve as directors and officers.

Registration Rights

For a description of registration rights with respect to our Class A common stock, please see the information under the heading Certain Relationships and Related Party Transactions Registration Rights Agreement.

Stockholders Agreement

For a description of rights of certain stockholders with respect to our Class A common stock, please see the information under the heading Certain Relationships and Related Party Transactions Stockholders Agreement.

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Transfer Agent and Registrar

The transfer agent and registrar for our Class A common stock is American Stock Transfer & Trust Company, LLC.

Listing

Our Class A common stock trades on the NYSE under the symbol ROAN .

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SHARES ELIGIBLE FOR FUTURE SALE

As of April 17, 2019, we have 152,539,532 shares of our Class A common stock outstanding none of which are freely tradeable without restriction or registration under the Securities Act. We are filing the registration statement of which this prospectus forms a part to register shares under the Securities Act on behalf of the selling stockholders. All other shares of our Class A common stock, except for shares of Class A common stock issuable under the MIP, are restricted securities within the meaning of Rule 144 under the Securities Act and may not be resold without resold or transferred unless such shares have been registered under the Securities Act or an exemption from registration is available, including exemptions in Rule 144. Future sales of our Class A common stock in the public market, or the availability of such shares for sale in the public market, could adversely affect the market price of our Class A common stock prevailing from time to time.

Registration Rights Agreement

For a description of registration rights with respect to our Class A common stock, see the information under the heading Certain Relationships and Related Party Transactions Registration Rights Agreement.

Rule 144

In general, under Rule 144 under the Securities Act as currently in effect, a person (or persons whose shares are aggregated) who is not deemed to have been an affiliate of ours at any time during the three months preceding a sale, and who has beneficially owned restricted securities within the meaning of Rule 144 for at least six months (including any period of consecutive ownership of preceding non-affiliated holders) would be entitled to sell those shares, subject only to the availability of current public information about us. A non-affiliated person who has beneficially owned restricted securities within the meaning of Rule 144 for at least one year would be entitled to sell those shares without regard to the provisions of Rule 144.

A person (or persons whose shares are aggregated) who is deemed to be an affiliate of ours and who has beneficially owned restricted securities within the meaning of Rule 144 for at least six months would be entitled to sell within any three-month period a number of shares that does not exceed the greater of one percent of the then outstanding shares of our Class A common stock or the average weekly trading volume of our Class A common stock reported through the NYSE during the four calendar weeks preceding the filing of notice of the sale. Such sales are also subject to certain manner of sale provisions, notice requirements and the availability of current public information about us.

Rule 701

In general, under Rule 701 under the Securities Act, any of our employees, directors, officers, consultants or advisors who purchase or otherwise receive shares from us in connection with a compensatory stock or option plan or other written agreement before the effective date of our registration statement on Form S-8 under the Securities Act to register such shares issued or issuable under the MIP are entitled to sell such shares 90 days after the effective date of such registration statement in reliance on Rule 144, without having to comply with the holding period requirement of Rule 144 and, in the case of non-affiliates, without having to comply with the public information, volume limitation or notice filing provisions of Rule 144. The SEC has indicated that Rule 701 will apply to typical stock options granted by an issuer before it becomes subject to the reporting requirements of the Exchange Act, along with the shares acquired upon exercise of such options, including exercises after the date of this prospectus.

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Long-Term Incentive Plan

We have filed a registration statement on Form S-8 under the Securities Act to register stock issuable under the MIP. This registration statement on Form S-8 was effective upon filing. Accordingly, shares registered under such registration statement are available for sale in the open market following the effective date, unless such shares are subject to vesting restrictions with us or the lock-up restrictions described above.

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MATERIAL U.S. FEDERAL INCOME TAX CONSIDERATIONS FOR NON-U.S. HOLDERS

The following is a summary of the material U.S. federal income tax considerations related to the purchase, ownership and disposition of our Class A common stock by a non-U.S. holder (as defined below) that holds our Class A common stock as a capital asset (generally property held for investment). This summary is based on the provisions of the Code, U.S. Treasury regulations, administrative rulings and judicial decisions, all as in effect on the date hereof, and all of which are subject to change, possibly with retroactive effect. We have not sought any ruling from the Internal Revenue Service (IRS) with respect to the statements made and the conclusions reached in the following summary, and there can be no assurance that the IRS or a court will agree with such statements and conclusions.

This summary does not address all aspects of U.S. federal income taxation that may be relevant to non-U.S. holders in light of their personal circumstances. In addition, this summary does not address the Medicare tax on certain investment income, U.S. federal estate or gift tax laws, any state, local or non-U.S. tax laws or any tax treaties. This summary also does not address tax considerations applicable to investors that may be subject to special treatment under the U.S. federal income tax laws, such as:

- banks, insurance companies or other financial institutions;
- tax-exempt or governmental organizations;
- qualified foreign pension funds (or any entities all of the interests of which are held by a qualified foreign pension fund);
- dealers in securities or foreign currencies;
- persons whose functional currency is not the U.S. dollar;
- controlled foreign corporations, passive foreign investment companies, and corporations that accumulate earnings to avoid U.S. federal income tax;
- traders in securities that use the mark-to-market method of accounting for U.S. federal income tax purposes;
- persons subject to the alternative minimum tax;
- partnerships or other pass-through entities for U.S. federal income tax purposes or holders of interests therein;

- persons deemed to sell our Class A common stock under the constructive sale provisions of the Code;
- persons that acquired our Class A common stock through the exercise of employee stock options or otherwise as compensation or through a tax-qualified retirement plan;
- certain former citizens or long-term residents of the United States; and
- persons that hold our Class A common stock as part of a straddle, appreciated financial position, synthetic security, hedge, conversion transaction or other integrated investment or risk reduction transaction.

PROSPECTIVE INVESTORS ARE ENCOURAGED TO CONSULT THEIR TAX ADVISORS WITH RESPECT TO THE APPLICATION OF THE U.S. FEDERAL INCOME TAX LAWS TO THEIR PARTICULAR SITUATION, AS WELL AS ANY TAX CONSEQUENCES OF THE PURCHASE, OWNERSHIP AND DISPOSITION OF OUR CLASS A COMMON STOCK ARISING UNDER THE U.S. FEDERAL ESTATE OR GIFT TAX LAWS OR UNDER THE LAWS OF ANY STATE, LOCAL, NON-U.S. OR OTHER TAXING JURISDICTION OR UNDER ANY APPLICABLE INCOME TAX TREATY.

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Non-U.S. Holder Defined

For purposes of this discussion, a non-U.S. holder is a beneficial owner of our Class A common stock that is not for U.S. federal income tax purposes a partnership or any of the following:

- an individual who is a citizen or resident of the United States;
- a corporation (or other entity treated as a corporation for U.S. federal income tax purposes) created or organized in or under the laws of the United States, any state thereof or the District of Columbia;
- an estate the income of which is subject to U.S. federal income tax regardless of its source; or
- a trust (i) the administration of which is subject to the primary supervision of a U.S. court and which has one or more United States persons who have the authority to control all substantial decisions of the trust or (ii) which has made a valid election under applicable U.S. Treasury regulations to be treated as a United States person.

If a partnership (including an entity or arrangement treated as a partnership for U.S. federal income tax purposes) holds our Class A common stock, the tax treatment of a partner in the partnership generally will depend upon the status of the partner, upon the activities of the partnership and upon certain determinations made at the partner level. Accordingly, we urge partners in partnerships (including entities or arrangements treated as partnerships for U.S. federal income tax purposes) considering the purchase of our Class A common stock to consult their tax advisors regarding the U.S. federal income tax considerations of the purchase, ownership and disposition of our Class A common stock by such partnership.

Distributions

We do not expect to pay any distributions on our Class A common stock in the foreseeable future. However, in the event we do make distributions of cash or other property on our Class A common stock, such distributions will constitute dividends for U.S. federal income tax purposes to the extent paid from our current or accumulated earnings and profits, as determined under U.S. federal income tax principles. To the extent those distributions exceed our current and accumulated earnings and profits, the distributions will be treated as a non-taxable return of capital to the extent of the non-U.S. holder s tax basis in our Class A common stock and thereafter as capital gain from the sale or exchange of such Class A common stock. See Gain on Disposition of Class A Common Stock. Subject to the withholding requirements under FATCA (as defined below) and with respect to effectively connected dividends, each of which is discussed below, any distribution made to a non-U.S. holder on our Class A common stock generally will be subject to U.S. withholding tax at a rate of 30% of the gross amount of the distribution unless an applicable income tax treaty provides for a lower rate. To receive the benefit of a reduced treaty rate, a non-U.S. holder must provide the applicable withholding agent with an IRS Form W-8BEN or IRS Form W-8BEN-E (or other applicable or successor form) certifying qualification for the reduced rate.

Dividends paid to a non-U.S. holder that are effectively connected with a trade or business conducted by the non-U.S. holder in the United States (and, if required by an applicable income tax treaty, are treated as attributable to a permanent establishment maintained by the non-U.S. holder in the United States) generally will be taxed on a net income basis at the rates and in the manner generally applicable to United States persons (as defined under the Code). Such effectively connected dividends will not be subject to U.S. withholding tax if the non-U.S. holder satisfies certain certification requirements by providing the applicable withholding agent with a properly executed IRS Form W-8ECI certifying eligibility for exemption. If the non-U.S. holder is a corporation for U.S. federal income tax purposes, it may also be subject to a branch profits tax (at a 30% rate or such lower rate as specified by an applicable income tax treaty) on its effectively connected earnings and profits (as adjusted for certain items), which will include effectively connected dividends.

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Gain on Disposition of Class A Common Stock

Subject to the discussions below under Backup Withholding and Information Reporting and Additional Withholding Requirements under FATCA, a non-U.S. holder generally will not be subject to U.S. federal income or withholding tax on any gain realized upon the sale or other disposition of our Class A common stock unless:

- the non-U.S. holder is an individual who is present in the United States for a period or periods aggregating 183 days or more during the calendar year in which the sale or disposition occurs and certain other conditions are met;
- the gain is effectively connected with a trade or business conducted by the non-U.S. holder in the United States (and, if required by an applicable income tax treaty, is attributable to a permanent establishment maintained by the non-U.S. holder in the United States); or
- our Class A common stock constitutes a United States real property interest by reason of our status as a United States real property holding corporation (USRPHC) for U.S. federal income tax purposes and as a result such gain is treated as effectively connected with a trade or business conducted by the non-U.S. holder in the United States.

A non-U.S. holder described in the first bullet point above will be subject to U.S. federal income tax at a rate of 30% (or such lower rate as specified by an applicable income tax treaty) on the amount of such gain, which generally may be offset by U.S. source capital losses.

A non-U.S. holder whose gain is described in the second bullet point above or, subject to the exceptions described in the next paragraph, the third bullet point above, generally will be taxed on a net income basis at the rates and in the manner generally applicable to United States persons (as defined under the Code) unless an applicable income tax treaty provides otherwise. If the non-U.S. holder is a corporation for U.S. federal income tax purposes whose gain is described in the second bullet point above, then such gain would also be included in its effectively connected earnings and profits (as adjusted for certain items), which may be subject to a branch profits tax (at a 30% rate or such lower rate as specified by an applicable income tax treaty).

Generally, a corporation is a USRPHC if the fair market value of its United States real property interests equals or exceeds 50% of the sum of the fair market value of its worldwide real property interests and its other assets used or held for use in a trade or business. We believe that we currently are, and expect to remain for the foreseeable future, a USRPHC for U.S. federal income tax purposes. However, as long as our Class A common stock is and continues to be regularly traded on an established securities market (within the meaning of the U.S. Treasury regulations), only a non-U.S. holder that actually or constructively owns, or owned at any time during the shorter of the five-year period ending on the date of the disposition or the non-U.S. holder s holding period for the Class A common stock, more than 5% of our Class A common stock will be treated as disposing of a U.S. real property interest and will be taxable on gain realized on the disposition of our Class A common stock as a result of our status as a USRPHC. If our Class A common stock were not considered to be regularly traded on an established securities market, such holder (regardless of the percentage of stock owned) would be treated as disposing of a U.S. real property interest and would be subject to U.S. federal income tax on a taxable disposition of our Class A common stock (as described in the preceding paragraph), and a 15% withholding tax would apply to the gross proceeds from such disposition.

Non-U.S. holders should consult their tax advisors with respect to the application of the foregoing rules to their ownership and disposition of our Class A common stock.

Backup Withholding and Information Reporting

Any dividends paid to a non-U.S. holder must be reported annually to the IRS and to the non-U.S. holder. Copies of these information returns may be made available to the tax authorities in the country in which the non-U.S. holder resides or is established. Payments of dividends to a non-U.S. holder generally will not be subject to backup withholding if the non-U.S. holder establishes an exemption by properly certifying its non-U.S. status on an IRS Form W-8BEN or IRS Form W-8BEN-E (or other applicable or successor form).

Payments of the proceeds from a sale or other disposition by a non-U.S. holder of our Class A common stock effected by or through a U.S. office of a broker generally will be subject to information reporting and backup withholding (at the applicable rate) unless the non-U.S. holder establishes an exemption by properly certifying its non-U.S. status on an IRS Form W-8BEN or IRS Form W-8BEN-E (or other applicable or successor form) and certain other conditions are met. Information reporting and backup withholding generally will not apply to any payment of the proceeds from a sale or other disposition of our Class A common stock effected outside the United States by a non-U.S. office of a broker. However, unless such broker has documentary evidence in its records that the non-U.S. holder is not a United States person and certain other conditions are met, or the non-U.S. holder otherwise establishes an exemption, information reporting will apply to a payment of the proceeds of the disposition of our Class A common stock effected outside the United States by such a broker if it has certain relationships within the United States.

Backup withholding is not an additional tax. Rather, the U.S. federal income tax liability (if any) of persons subject to backup withholding will be reduced by the amount of tax withheld. If backup withholding results in an overpayment of taxes, a refund may be obtained, provided that the required information is timely furnished to the IRS.

Additional Withholding Requirements under FATCA

Sections 1471 through 1474 of the Code, and the U.S. Treasury regulations and administrative guidance issued thereunder (FATCA), impose a 30% withholding tax on any dividends paid on our Class A common stock and on the gross proceeds from a disposition of our Class A common stock (if such disposition occurs after December 31, 2018), in each case if paid to a foreign financial institution or a non-financial foreign entity (each as defined in the Code) (including, in some cases, when such foreign financial institution or non-financial foreign entity is acting as an intermediary), unless (i) in the case of a foreign financial institution, such institution enters into an agreement with the U.S. government to withhold on certain payments, and to collect and provide to the U.S. tax authorities substantial information regarding U.S. account holders of such institution (which includes certain equity and debt holders of such institution, as well as certain account holders that are non-U.S. entities with U.S. owners), (ii) in the case of a non-financial foreign entity, such entity certifies that it does not have any substantial United States owners (as defined in the Code) or provides the applicable withholding agent with a certification identifying the direct and indirect substantial United States owners of the entity (in either case, generally on an IRS Form W-8BEN-E), or (iii) the foreign financial institution or non-financial foreign entity otherwise qualifies for an exemption from these rules and provides appropriate documentation (such as an IRS Form W-8BEN-E). Foreign financial institutions located in jurisdictions that have an intergovernmental agreement with the United States governing these rules may be subject to different rules. Under certain circumstances, a holder might be eligible for refunds or credits of such taxes. Non-U.S. holders are encouraged to consult their own tax advisors regarding the effects of FATCA on an investment in our Class A common stock.

INVESTORS CONSIDERING THE PURCHASE OF OUR CLASS A COMMON STOCK ARE URGED TO CONSULT THEIR OWN TAX ADVISORS REGARDING THE APPLICATION OF THE U.S. FEDERAL INCOME TAX LAWS TO THEIR PARTICULAR SITUATIONS AND THE APPLICABILITY AND EFFECT OF U.S. FEDERAL ESTATE AND GIFT TAX LAWS AND ANY STATE, LOCAL OR NON-U.S. TAX LAWS AND TAX TREATIES.

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CERTAIN ERISA CONSIDERATIONS

The following is a summary of certain considerations associated with the acquisition and holding of shares of Class A common stock by employee benefit plans that are subject to Title I of the Employee Retirement Income Security Act of 1974, as amended (ERISA), plans, individual retirement accounts and other arrangements that are subject to Section 4975 the Code or employee benefit plans that are governmental plans (as defined in Section 3(32) of ERISA), certain church plans (as defined in Section 3(33) of ERISA), non-U.S. plans (as described in Section 4(b)(4) of ERISA) or other plans that are not subject to the foregoing but may be subject to provisions under any other federal, state, local, non-U.S. or other laws or regulations that are similar to such provisions of ERISA or the Code (collectively, Similar Laws), and entities whose underlying assets are considered to include plan assets of any such plan, account or arrangement (each, a Plan).

This summary is based on the provisions of ERISA and the Code (and related regulations and administrative and judicial interpretations) as of the date of this prospectus. This summary does not purport to be complete, and no assurance can be given that future legislation, court decisions, regulations, rulings or pronouncements will not significantly modify the requirements summarized below. Any of these changes may be retroactive and may thereby apply to transactions entered into prior to the date of their enactment or release. This discussion is general in nature and is not intended to be all inclusive, nor should it be construed as investment or legal advice.

General Fiduciary Matters

ERISA and the Code impose certain duties on persons who are fiduciaries of a Plan subject to Title I of ERISA or Section 4975 of the Code (an ERISA Plan) and prohibit certain transactions involving the assets of an ERISA Plan and its fiduciaries or other interested parties. Under ERISA and the Code, any person who exercises any discretionary authority or control over the administration of an ERISA Plan or the management or disposition of the assets of an ERISA Plan, or who renders investment advice for a fee or other compensation to an ERISA Plan, is generally considered to be a fiduciary of the ERISA Plan.

In considering an investment in shares of Class A common stock with a portion of the assets of any Plan, a fiduciary should consider the Plan s particular circumstances and all of the facts and circumstances of the investment and determine whether the acquisition and holding of shares of Class A common stock is in accordance with the documents and instruments governing the Plan and the applicable provisions of ERISA, the Code, or any Similar Law relating to the fiduciary s duties to the Plan, including, without limitation:

- whether the investment is prudent under Section 404(a)(1)(B) of ERISA and any other applicable Similar Laws;

- whether, in making the investment, the ERISA Plan will satisfy the diversification requirements of Section 404(a)(1)(C) of ERISA and any other applicable Similar Laws;

- whether the investment is permitted under the terms of the applicable documents governing the Plan;

whether the acquisition or holding of the shares of Class A common stock will constitute a prohibited transaction under Section 406 of ERISA or Section 4975 of the Code (please see the discussion under Prohibited Transaction Issues below); and

whether the Plan will be considered to hold, as plan assets, (i) only shares of Class A common stock or (ii) an undivided interest in our underlying assets (please see the discussion under Plan Asset Issues below).

Prohibited Transaction Issues

Section 406 of ERISA and Section 4975 of the Code prohibit ERISA Plans from engaging in specified transactions involving plan assets with persons or entities who are parties in interest, within the meaning of ERISA, or disqualified persons, within the meaning of Section 4975 of the Code, unless an exemption is available. A party in interest or disqualified person who engages in a non-exempt prohibited transaction may be subject to excise taxes and other penalties and liabilities under ERISA and the Code. In addition, the fiduciary of the ERISA Plan that engages in such a non-exempt prohibited transaction may be subject to penalties and liabilities under ERISA and the Code. The acquisition and/or holding of shares of Class A common stock by an ERISA Plan with respect to which the issuer, the initial purchaser, or a guarantor is considered a party in interest or a disqualified person may constitute or result in a direct or indirect prohibited transaction under Section 406 of ERISA and/or Section 4975 of the Code, unless the investment is acquired and is held in accordance with an applicable statutory, class or individual prohibited transaction exemption.

Because of the foregoing, shares of Class A common stock should not be acquired or held by any person investing plan assets of any Plan, unless such acquisition and holding will not constitute a non-exempt prohibited transaction under ERISA and the Code or a similar violation of any applicable Similar Laws.

Plan Asset Issues

Additionally, a fiduciary of a Plan should consider whether the Plan will, by investing in us, be deemed to own an undivided interest in our assets, with the result that we would become a fiduciary of the Plan and our operations would be subject to the regulatory restrictions of ERISA, including its prohibited transaction rules, as well as the prohibited transaction rules of the Code and any other applicable Similar Laws.

The Department of Labor (the DOL) regulations provide guidance with respect to whether the assets of an entity in which ERISA Plans acquire equity interests would be deemed plan assets under some circumstances. Under these regulations, an entity s assets generally would not be considered to be plan assets if, among other things:

(a) the equity interests acquired by ERISA Plans are publicly offered securities (as defined in the DOL regulations) i.e., the equity interests are part of a class of securities that is widely held by 100 or more investors independent of the issuer and each other, are freely transferable, and are either registered under certain provisions of the federal securities laws or sold to the ERISA Plan as part of a public offering under certain conditions;

(b) the entity is an operating company (as defined in the DOL regulations) i.e., it is primarily engaged in the production or sale of a product or service, other than the investment of capital, either directly or through a majority-owned subsidiary or subsidiaries; or

(c) there is no significant investment by benefit plan investors (as defined in the DOL regulations) i.e., immediately after the most recent acquisition by an ERISA Plan of any equity interest in the entity, less than 25% of the total value of each class of equity interest (disregarding certain interests held by persons (other than benefit plan investors) with discretionary authority or control over the assets of the entity or who provide investment advice for a fee (direct or indirect) with respect to such assets, and any affiliates thereof) is held by ERISA Plans, IRAs and certain other Plans (but not including governmental plans, foreign plans and certain church plans), and entities whose underlying assets are deemed to include plan assets by reason of a Plan s investment in the entity.

Due to the complexity of these rules and the excise taxes, penalties and liabilities that may be imposed upon persons involved in non-exempt prohibited transactions, it is particularly important that fiduciaries, or other persons considering acquiring and/or holding shares of our Class A common stock on behalf of, or with the assets of, any Plan, consult with their counsel regarding the potential applicability of ERISA, Section 4975 of the Code and any Similar Laws to such investment and whether an exemption would be applicable to the acquisition and holding of shares of Class A common stock. Purchasers of shares of Class A common stock have the exclusive responsibility for ensuring that their acquisition and holding of shares of Class A common stock complies with the fiduciary responsibility rules of ERISA and does not violate the prohibited transaction rules of ERISA, the Code or applicable Similar Laws. The sale of shares of Class A common stock to a Plan is in no respect a representation by us or any of our affiliates or representatives that such an investment meets all relevant legal requirements with respect to investments by any such Plan or that such investment is appropriate for any such Plan.

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PLAN OF DISTRIBUTION

The selling stockholders may, from time to time, sell, transfer or otherwise dispose of any or all of their shares or interests in the shares on any stock exchange, market or trading facility on which the shares are traded or in private transactions. The selling stockholders may sell their shares of Class A common stock from time to time at the prevailing market price or in privately negotiated transactions.

The selling stockholders may use any one or more of the following methods when disposing of shares or interests therein:

- ordinary brokerage transactions and transactions in which the broker-dealer solicits purchasers;
- block trades in which the broker-dealer will attempt to sell the shares as agent, but may position and resell a portion of the block as principal to facilitate the transaction;
- purchases by a broker-dealer as principal and resale by the broker-dealer for its account;
- an exchange distribution in accordance with the rules of the applicable exchange;
- privately negotiated transactions;
- in underwritten transactions;
- short sales effected after the date the registration statement of which this prospectus is a part is declared effective by the SEC;
- through the writing or settlement of options or other hedging transactions, whether through an options exchange or otherwise;
- broker-dealers may agree with the selling stockholders to sell a specified number of such shares at a stipulated price per share; and
- a combination of any such methods of sale.

The selling stockholders may sell the shares at fixed prices, at prices then prevailing or related to the then current market price or at negotiated prices. The offering price of the shares from time to time will be determined by the selling stockholders and, at the time of the determination, may be higher or lower than the market price of our Class A common stock on the NYSE or any other exchange or market.

The shares may be sold directly or through broker-dealers acting as principal or agent, or pursuant to a distribution by one or more underwriters on a firm commitment or best-efforts basis. The selling stockholders may also enter into hedging transactions with broker-dealers. In connection with such transactions, broker-dealers of other financial institutions may engage in short sales of our Class A common stock in the course of hedging the positions they assume with the selling stockholders. The selling stockholders may also enter into options or other transactions with broker-dealers or other financial institutions which require the delivery to such broker-dealer or other financial institution of shares offered by this prospectus, which shares such broker-dealer or other financial institution may resell pursuant to this prospectus (as supplemented or amended to reflect such transaction). In connection with an underwritten offering, underwriters or agents may receive compensation in the form of discounts, concessions or commissions from the selling stockholders or from purchasers of the offered shares for whom they may act as agents. In addition, underwriters may sell the shares to or through dealers, and those dealers may receive compensation in the form of discounts, concessions or commissions from the underwriters and/or commissions from the purchasers for whom they may act as agents. The selling stockholders and any underwriters, dealers or agents participating in a distribution of the shares may be deemed to be underwriters within the meaning of the Securities Act, and any profit on the sale of the shares by the selling stockholders and any commissions received by broker-dealers may be deemed to be underwriting commissions under the Securities Act.

The selling stockholders may agree to indemnify an underwriter, broker-dealer or agent against certain liabilities related to the selling of their shares, including liabilities arising under the Securities Act. Under the

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registration rights agreement with the selling stockholders, we have agreed to indemnify the selling stockholders against certain liabilities related to the sale of the Class A common stock, including certain liabilities arising under the Securities Act. Under the registration rights agreement, we have also agreed to pay the costs, expenses and fees of registering the shares of Class A common stock, including the reasonable legal fees of the selling stockholders. All other expenses of issuance and distribution including brokers or underwriters discounts and commissions, if any, and all transfer taxes and transfer fees relating to the sale or disposition of the selling stockholders will be borne by the selling stockholders.

The selling stockholders are subject to the applicable provisions of the Exchange Act, and the rules and regulations under the Exchange Act, including Regulation M. This regulation may limit the timing of purchases and sales of any of the shares of Class A common stock offered in this prospectus by the selling stockholders. The anti-manipulation rules under the Exchange Act may apply to sales of shares in the market and to the activities of the selling stockholders and its affiliates. Furthermore, Regulation M may restrict the ability of any person engaged in the distribution of the shares to engage in market-making activities for the particular securities being distributed for a period of up to five business days before the distribution. The restrictions may affect the marketability of the shares and the ability of any person or entity to engage in market-making activities for the shares.

To the extent required, this prospectus may be amended and/or supplemented from time to time to describe a specific plan of distribution. Instead of selling the shares of Class A common stock under this prospectus, the selling stockholders may sell the shares of Class A common stock in compliance with the provisions of Rule 144 under the Securities Act, if available, or pursuant to other available exemptions from the registration requirements of the Securities Act.

We are required to pay certain fees and expenses incurred by us incident to the registration of the shares. We have agreed to indemnify the selling stockholders against certain losses, claims, damages and liabilities, including liabilities under the Securities Act. Each selling stockholder has in turn agreed to indemnify us for certain specified liabilities.

Under the securities laws of some states, if applicable, the securities registered hereby may be sold in those states only through registered or licensed brokers or dealers. In addition, in some states such securities may not be sold unless they have been registered or qualified for sale or an exemption from registration or qualification requirements is available and is complied with.

We cannot assure you that the selling stockholders will sell all or any portion of our Class A common stock offered hereby.

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LEGAL MATTERS

The validity of our Class A common stock offered by this prospectus will be passed upon for us and the selling stockholders by Vinson & Elkins L.L.P., Houston, Texas.

EXPERTS

The financial statements as of December 31, 2018 and 2017 and for each of the three years in the period ended December 31, 2018 included in this prospectus have been so included in reliance on the report of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The financial statements of certain oil and natural gas properties contributed by Linn Energy, Inc., which comprise the statements of revenues and direct operating expenses for the eight months ended August 31, 2017 and for the years ended December 31, 2016 and 2015, included in this prospectus have been so included in reliance on the report (which contains an emphasis of matter paragraph relating to the basis of presentation as described in Note 1 to the financial statements) of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

Estimates of our reserves and related future net cash flows related to our properties as of December 31, 2018, included herein and elsewhere in the registration statement were based upon a reserve report prepared by independent petroleum engineers, DeGolyer and MacNaughton. We have included these estimates in reliance on the authority of such firm as an expert in such matters.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form S-1 (including the exhibits, schedules and amendments thereto) under the Securities Act, with respect to the shares of our Class A common stock offered hereby. This prospectus is part of, and does not contain all of the information set forth in, the registration statement and the exhibits and schedules thereto. For further information with respect to the Class A common stock offered hereby, we refer you to the registration statement and the exhibits and schedules filed therewith. Statements contained in this prospectus as to the contents of any contract, agreement or any other document are summaries of the material terms of such contract, agreement or other document and are not necessarily complete. With respect to each of these contracts, agreements or other documents filed as an exhibit to the registration statement, reference is made to the exhibits for a more complete description of the matter involved. The SEC maintains a website *at www.sec.gov*. Our registration statement, of which this prospectus forms a part, can be downloaded from the SEC s website.

We are subject to full information requirements of the Exchange Act. We will fulfill our obligations with respect to such requirements by filing periodic reports and other information with the SEC. We intend to furnish our stockholders with annual reports containing financial statements certified by an independent public accounting firm.

Our website is included in this prospectus as an inactive textual reference only. The information found on our website is not part of this prospectus or any report filed with or furnished to the SEC.

INDEX TO FINANCIAL STATEMENTS

ROAN RESOURCES, INC.

UNAUDITED PRO FORMA CONDENSED FINANCIAL INFORMATION

On September 24, 2018, a series of transactions were executed that resulted in Linn Energy Holdings, LLC (LEH) and Linn Operating, LLC (LOI , and together with LEH, Linn) and Citizen Energy II, LLC (Citizen) contributing their equity interest in Roan Resources LLC (Roan LLC) to two new subsidiaries that are wholly owned by Roan Resources, Inc. (Roan Inc.) in exchange for equity interest in Roan Inc. (the Reorganization). Following the Reorganization, Roan Inc. became the successor of Linn in accordance with Rule 15d-5 of the Securities Exchange Act of 1934.

The unaudited pro forma condensed statement of operations for the year ended December 31, 2018 was based on the audited statement of operations of Roan Inc. for the year ended December 31, 2018 and includes pro forma adjustments to give effect to the Reorganization as if it had occurred on January 1, 2018.

This unaudited pro forma condensed statement of operations for the year ended December 31, 2018 is provided for illustrative purposes only and is not indicative of the results that actually would have occurred had the transactions been in effect on the dates or for the periods indicated, or of results that may occur in the future. This unaudited pro forma condensed financial statement should be read in conjunction with our historical financial statements.

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Roan Resources, Inc.

Unaudited Pro Forma Condensed Statement of Operations

Year Ending December 31, 2018

	Roan Inc. Historical	Reorganization Adjustments	Roan Inc. Pro Forma
	(in thousands, except earnings per share data)		
Revenues			
Oil sales	$ 275,239	$	$ 275,239
Natural gas sales	46,966		46,966
Natural gas sales Affiliates	29,090		29,090
Natural gas liquids sales	51,467		51,467
Natural gas liquids sales Affiliates	37,005		37,005
Gain on derivative contracts	78,054		78,054
Total revenues	517,821		517,821
Operating expenses			
Production expenses	47,600		47,600
Production taxes	17,579		17,579
Exploration expenses	43,303		43,303
Depreciation, depletion and amortization	123,922		123,922
General and administrative	60,874	(4,577) (a)	56,297
Total operating expenses	293,278	(4,577)	288,701
Total operating income	224,543	4,577	229,120
Other income (expense)			
Interest expense	(8,352)		(8,352)
Income before income taxes	216,191	4,577	220,768
		(304,455) (b)	
Income tax expense	356,862	3,889 (c)	56,296
Net (loss) income	$ (140,671)	$ (303,767)	$ 164,472
Earnings (loss) per share:			
Basic	$ (0.92)		$ 1.08
Diluted	$ (0.92)		$ 1.08
Weighted average number of shares outstanding:			
Basic	152,232	308 (d)	152,540
Diluted	152,232	308 (d)	152,540

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ROAN RESOURCES, INC.

NOTES TO PRO FORMA CONDENSED FINANCIAL STATEMENTS

(UNAUDITED)

1. Basis of Presentation

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 is derived from the historical financial statements of Roan Inc. The unaudited pro forma condensed statement of operations for the year ended December 31, 2018 assumes that the Reorganization occurred on January 1, 2018. The historical financial statements have been adjusted in the unaudited pro forma condensed financial statements to give effect to events that are (1) directly attributable to the Reorganization, (2) factually supportable and (3) with respect to the statements of operations, expected to have a continuing impact on the results.

This unaudited pro forma condensed financial statement is provided for illustrative purposes only and may or may not provide an indication of results in the future.

2. Pro Forma Adjustments

The following adjustments were made in the preparation of the unaudited pro forma condensed financial statements.

(a) Adjustment to remove the non-recurring transaction costs incurred by Roan Inc. associated with the Reorganization.

(b) Reflects an adjustment to reverse the income tax expense associated with the initial deferred tax liability recognized as a result of the Reorganization. Roan Inc. is taxable as a corporation under the Internal Revenue Code of 1986, as amended, and as a result, is subject to federal, state and local income taxes. 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 federal income tax purposes, were deemed to pass to the members. Accordingly, no tax provision was made in the historical financial statements of Roan LLC since the income tax was an obligation of the members. The initial recording of the deferred tax liability has been reflected in the historical financial statements, but is not included in the accompanying unaudited pro forma condensed statement of operations due to its non-recurring nature.

(c) Adjustment to reflect income tax expense based on the statutory tax rate of 25.5% to prospective periods. As there was no tax provision in the historical financial statements of Roan LLC, it was deemed appropriate to use the statutory tax rate as of December 31, 2018 for purposes of calculating the income tax expense for the period from January 1, 2018 through September 24, 2018, the date of the Reorganization.

(d) The pro forma weighted average number of shares outstanding reflects the weighted average number of shares of common stock we would have had outstanding if the Reorganization had occurred on January 1, 2018.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Roan Resources, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Roan Resources, Inc. and its subsidiaries (the Company) as of December 31, 2018 and 2017, and the related consolidated statements of operations, of changes in equity and of cash flows for each of the three years in the period ended December 31, 2018, including the related notes (collectively referred to as the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 3 to the consolidated financial statements, the Company changed the manner in which it accounts for revenue from contracts with customers in 2018.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on the Company s consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma

April 1, 2019

We have served as the Company s auditor since 2016.

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Roan Resources, Inc.

Consolidated Balance Sheets

	December 31, 2018	December 31, 2017
	(in thousands, except par value and share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 6,883	$ 1,471
Accounts receivable		
Oil, natural gas and natural gas liquid sales	55,564	74,527
Affiliates	9,669	4,695
Joint interest owners and other, net	133,387	320
Prepaid drilling advances	28,977	
Derivative contracts	82,180	152
Prepaid expenses	2,644	651
Other current assets	4,011	279
Total current assets	323,315	82,095
Noncurrent assets		
Oil and natural gas properties, successful efforts method	2,628,333	1,876,951
Accumulated depreciation, depletion, amortization and impairment	(230,836)	(78,307)
Oil and natural gas properties, net	2,397,497	1,798,644
Derivative contracts	20,638	996
Other	7,659	3,857
Total assets	$ 2,749,109	$ 1,885,592
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable	$ 49,746	$
Accrued liabilities	176,494	10,245
Accounts payable and accrued liabilities Affiliates	8,577	183,820
Revenue payable	97,963	
Drilling advances	31,058	
Derivative contracts	845	9,279
Asset retirement obligations	790	
Total current liabilities	365,473	203,344
Noncurrent liabilities		
Long-term debt	514,639	85,339

Deferred tax liabilities, net	356,862	
Asset retirement obligations	16,058	10,769
Derivative contracts	141	1,371
Other	902	
Total liabilities	1,254,075	300,823
Commitments and contingencies (Note 14)		
Equity		
Common stock, $0.001 par value; 800,000,000 shares authorized; 152,539,532 shares issued and outstanding at December 31, 2018	153	
Preferred stock, $0.001 par value; 50,000,000 shares authorized; no shares issued and outstanding at December 31, 2018		
Additional paid-in capital	1,646,401	
Accumulated deficit	(151,520)	
Members equity		1,584,769
Total equity	1,495,034	1,584,769
Total liabilities and equity	$ 2,749,109	$ 1,885,592

The accompanying notes are an integral part of these consolidated financial statements.

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Roan Resources, Inc.

Consolidated Statements of Operations

	Year Ended December 31,		
	2018	2017	2016
	(in thousands, except per share data)		
Revenues			
Oil sales	$ 275,239	$ 76,876	$ 30,565
Natural gas sales	46,966	46,303	16,093
Natural gas sales Affiliates	29,090	2,908	
Natural gas liquid sales	51,467	35,217	8,307
Natural gas liquid sales Affiliates	37,005	5,081	
Gain (loss) on derivative contracts	78,054	(6,797)	
Total revenues	517,821	159,588	54,965
Operating Expenses			
Production expenses	47,600	16,872	5,090
Gathering, transportation and processing		18,602	5,920
Production taxes	17,579	3,685	1,087
Exploration expenses	43,303	32,629	5,258
Depreciation, depletion, amortization and accretion	123,922	37,376	24,996
General and administrative	60,874	31,357	5,581
Gain on sale of oil and natural gas properties		(838)	
Total operating expenses	293,278	139,683	47,932
Total operating income	224,543	19,905	7,033
Other income (expense)			
Interest expense, net	(8,352)	(1,461)	(86)
Other income		13	
Net income before income taxes	216,191	18,457	6,947
Income tax expense	356,862		
Net (loss) income	$ (140,671)	$ 18,457	$ 6,947
Earnings (loss) per share			
Basic	$ (0.92)	$ 0.18	$ 0.11
Diluted	$ (0.92)	$ 0.18	$ 0.11
Weighted average number of shares outstanding			
Basic	152,232	100,473	62,394
Diluted	152,232	100,473	62,394

The accompanying notes are an integral part of these consolidated financial statements.

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Roan Resources, Inc.

Consolidated Statements of Changes in Equity

	Stockholders Equity					
	Common Stock (Shares)	**Common Stock**	**Additional Paid-in Capital**	**Accumulated Deficit**	**Members Equity**	**Total Equity**
				(in thousands)		
Balance at December 31, 2015		$	$	$	$ 98,292	$ 98,292
Contributions from Citizen Members					169,008	169,008
Net income					6,947	6,947
Balance at December 31, 2016					274,247	274,247
Contributions from Citizen Members					95,557	95,557
Distributions to Citizen Members					(85,614)	(85,614)
Acquisition of oil and natural gas properties in exchange for equity units					1,281,743	1,281,743
Equity-based compensation					379	379
Net income					18,457	18,457
Balance at December 31, 2017					1,584,769	1,584,769
Acquisition of oil and natural gas properties in exchange for equity units					39,906	39,906
Equity-based compensation [(1)]			3,162		7,868	11,030
Net (loss) income [(1)]				(151,520)	10,849	(140,671)
Issuance of common stock upon Reorganization	152,540	153	1,643,239		(1,643,392)	
Balance at December 31, 2018	152,540	$ 153	$ 1,646,401	$ (151,520)	$	$ 1,495,034

(1) Amounts are allocated to stockholders equity and members equity to reflect the Reorganization. See *Note 10 Equity* for discussion of the Reorganization.

The accompanying notes are an integral part of these consolidated financial statements.

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Roan Resources, Inc.

Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2018	**2017**	**2016**
		(in thousands)	
Cash flows from operating activities			
Net (loss) income	$ (140,671)	$ 18,457	$ 6,947
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	123,922	37,376	24,996
Unproved leasehold amortization and impairment	36,046	25,377	5,258
Gain on sale of oil and natural gas properties		(838)	
Amortization of deferred financing costs	853	175	
Amortization of deferred rent	902		
(Gain) loss on derivative contracts	(78,054)	6,797	
Net cash (paid) received upon settlement of derivative contracts	(33,279)	2,705	
Equity-based compensation	11,030	379	
Deferred income taxes	356,862		
Other	2,971	(11)	(41)
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable Oil, natural gas and natural gas liquid sales	18,963	(62,170)	(12,473)
Accounts receivable Affiliates	(4,974)	(4,695)	
Accounts receivable Joint interest owners and other	(136,367)	(8,729)	(35,398)
Prepaid drilling advances	(28,977)		
Prepaid expenses	(1,992)	(2,312)	(1,221)
Other current assets	(2,584)	(2)	3
Accounts payable	16,733		6,006
Accrued liabilities	21,536	47,801	8,403
Accounts payable and accrued liabilities Affiliates	(23,645)	31,121	
Drilling advances	31,058	(25,363)	22,760
Revenue payable	97,963	(5,793)	10,900
Net cash provided by operating activities	268,296	60,275	36,140
Cash flows from investing activities			
Acquisition of oil and natural gas properties	(22,935)	(42,701)	(144,774)
Capital expenditures for oil and natural gas properties	(673,465)	(167,122)	(96,335)
Acquisition of other property and equipment	(3,237)	(1,332)	
Proceeds from sale of oil and natural gas properties	10,545	1,435	
Other		(2,801)	
Net cash used in investing activities	(689,092)	(212,521)	(241,109)
Cash flows from financing activities			
Proceeds from borrowings	429,300	105,339	20,000

Repayment of borrowings		(40,000)	
Deferred financing costs	(2,279)	(2,885)	
Deferred offering costs	(813)		
Contributions from Citizen members		95,557	169,008
Distributions to Citizen members		(11,147)	
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)
Cash and cash equivalents, beginning of year	1,471	6,853	22,814
Cash and cash equivalents, end of year	$ 6,883	$ 1,471	$ 6,853

The accompanying notes are an integral part of these consolidated financial statements.

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Roan Resources, Inc.

Consolidated Statements of Cash Flows, Continued

	Year Ended December 31,		
	2018	**2017**	**2016**
		(in thousands)	
Supplemental disclosure of cash flow information			
Cash paid for interest, net of capitalized interest	$ 7,029	$ 1,036	$ 86
Supplemental disclosure of non-cash investing and financing activities			
Change in accrued capital expenditures	$ 65,699	$ 147,142	$ 4,922
Acquisition of oil and natural gas properties for equity	$ 39,906	$ 1,281,743	$
Distribution to Citizen Members of assets and liabilities	$	$ (74,467)	$

The accompanying notes are an integral part of these consolidated financial statements.

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Roan Resources, Inc.

Notes to Consolidated Financial Statements

Note 1 Business and Organization

Roan Resources, Inc. (Roan Inc.) was formed in September 2018 to facilitate a reorganization and to become the holding company for Roan Resources LLC (Roan LLC). In September 2018, a series of transactions were executed with Roan LLC s members which resulted in Roan LLC becoming a wholly- owned subsidiary of Roan Inc. These transactions are hereafter referred to as the Reorganization and Roan Inc. with its subsidiaries are collectively referred to as the Company. See *Note 10 Equity* for further discussion of the Reorganization transaction. The accompanying historical financial statements through the date of Reorganization are the financial statements of Roan LLC, our accounting predecessor. Following the Reorganization, the historical financial statements are the results of Roan Inc.

Roan LLC was initially formed by Citizen Energy II, LLC (Citizen) in May 2017. On August 31, 2017, the Company executed a contribution agreement (the Contribution Agreement) by and among Roan LLC, Citizen, Linn Energy Holdings, LLC (LEH) and Linn Operating, LLC (LOI , and together with LEH, Linn) pursuant to which, among other things, Citizen and Linn agreed to contribute oil and natural gas properties within an area-of-mutual-interest to the Company (collectively the Contribution). In exchange for their contributions, Citizen and Linn each received a 50% equity interest in Roan LLC.

The contributions of oil and natural gas properties to Roan LLC by Citizen and Linn were determined to meet the definition of a business. However, as Roan LLC had no assets or operations prior to the Contribution, it was determined that Citizen was the acquirer for accounting purposes in accordance with ASC Topic 805, *Business Combinations*. As a result, the information in the accompanying financial statements and footnotes for the period prior to the Contribution reflects the historical results of Citizen. Citizen was formed in July 2014 to engage in the acquisition, exploration, development, production, and sale of oil and natural gas reserves in Central Oklahoma. Subsequent to the Contribution, the information in the accompanying financial statements and footnotes reflects the results of Roan LLC and after the Reorganization, the results of Roan Inc. See *Note 4 Acquisitions* for additional discussion of the business combination of the oil and natural gas properties contributed by Linn. In conjunction with the Contribution Agreement, the Company entered into management services agreements with both Citizen and Linn (MSAs) through April 2018. See *Note 12 Transactions with Affiliates* for additional discussion of the MSAs and transactions with Citizen and Linn.

The Company was formed to engage in the acquisition, exploration, development, production, and sale of oil and natural gas reserves. The Company s oil and natural gas properties are located in Central Oklahoma. The Company s corporate headquarters is located in Oklahoma City, Oklahoma.

Note 2 Basis of Presentation and Significant Accounting Policies

Basis of Presentation

The accompanying consolidated financial statements were prepared in conformity with accounting principles generally accepted in the United States of America (GAAP). The consolidated financial statements of the Company include the accounts of Roan Inc. and its wholly-owned subsidiaries. All intercompany balances and transactions have been eliminated.

Certain amounts in the prior period financial statements have been reclassified to conform to the 2018 presentation. These reclassifications had no impact on net income (loss), total stockholders equity or total cash flows.

Use of Estimates

The preparation of financial statements and related footnotes in conformity with GAAP requires that management formulate estimates and assumptions that affect revenues, expenses, assets, liabilities and the

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disclosure of contingent assets and liabilities. A significant item that requires management s estimates and assumptions is the estimate of proved oil, natural gas and NGL reserves which are used in the calculation of depletion of the Company s oil and natural gas properties and impairment, if any, of proved oil and natural gas properties. Changes in estimated quantities of its reserves could impact the Company s reported financial results as well as disclosures regarding the quantities and value of proved oil and natural gas reserves. Although management believes these estimates are reasonable, actual results could differ from these estimates.

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. See *Note 3 Revenue from Contracts with Customers* for additional discussion.

Fair Value Measurements

The Company follows a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company s assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1 Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.

Level 2 Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1 that are either directly or indirectly observable as of the reporting date.

Level 3 Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management s best estimate of fair value.

The Company recognizes transfers between fair value hierarchy levels as of the end of the reporting period in which the event or change in circumstances causing the transfer occurred. The Company did not have any transfers between Level 1, Level 2 or Level 3 fair value measurements during 2018 or 2017.

Business Combinations

The Company accounts 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.

The Company estimates the fair values of assets acquired and liabilities assumed in a business combination using various assumptions (all of which are 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, the Company

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develops 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. The Company estimates future prices to apply to the estimated net quantities of reserves based on the applicable ownership percentage acquired and estimates 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

The Company follows the successful efforts method to account for its 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. The Company initially capitalizes 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 proved reserves have been found, the costs of exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells.

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 is computed using the units-of-production method on a field level basis over the remaining estimated life of proved reserves. The Company determined its oil and natural gas properties are comprised of one single field. Capitalized drilling and development costs of producing oil and natural gas properties are amortized based on the total estimated proved developed reserves. 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. The Company recorded depletion expense on capitalized oil and natural gas properties of $122.2 million, $37.0 million, and $24.9 million for the years ended December 31, 2018, 2017, and 2016, respectively.

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 accumulate depreciation, depletion and amortization unless doing so significantly affect 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.

The Company capitalizes interest on expenditures made in connection with exploration and development projects that are not subject to current amortization. Interest is capitalized only for the period that activities are in progress to bring these projects to their intended use. The Company capitalized interest of $8.3 million for the year ended December 31, 2018. No interest was capitalized in the years ended December 31, 2017 or 2016.

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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.

The Company calculates 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. No impairment of proved oil and natural gas properties was recorded for the years ended December 31, 2018, 2017, and 2016.

The Company s 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. For the years ended December 31, 2017 and 2016, the Company recorded abandonment and impairment expense on its unproved oil and natural gas properties of $4.5 million and $5.3 million, respectively, for leases which have expired, or are expected to expire. Impairment expense on unproved oil and natural gas properties is included in exploration expense in the accompanying consolidated statements of operations. No impairment of unproved oil and natural gas properties was recorded for the year ended December 31, 2018.

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 the Company s 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. For the years ended December 31, 2018 and 2017, the Company recorded amortization expense on its unproved oil and natural gas properties of $36.0 million and $19.6 million, respectively, which is reflected in exploration expense on the accompanying consolidated statements of operations. There was no such expense recorded for the year ended December 31, 2016. Costs of expired or relinquished leases are charged against the valuation allowance.

Derivative Instruments

The Company has entered into commodity derivative instruments to reduce the effect of price changes on a portion of the Company s future oil and natural gas production.

The commodity derivative instruments are measured at fair value and are included in the balance sheet as derivative assets and derivative liabilities, on a net basis by counterparty. The Company adjusts the valuations

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from the valuation model for nonperformance risk and for counterparty risk. The fair values of the Company s 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. The Company has 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. The Company s 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 the Company s consolidated statements of cash flows. The Company s 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.

Accrued Liabilities

The components of accrued liabilities are presented below:

	December 31,	
	2018	**2017**
	(in thousands)	
Accrued capital expenditures	$ 151,965	$ 7,252
Accrued production expenses	10,879	
Accrued general and administrative expenses	7,450	2,696
Other	6,200	297
Total accrued liabilities	$ 176,494	$ 10,245

Drilling Advances

The Company s drilling advances consist of cash provided to the Company from its joint interest partners for planned drilling activities. Advances are applied against the joint interest partner s share of expenses incurred. As noted above, the Company entered into MSAs with Citizen and Linn to perform services, including operating the contributed assets. At December 31, 2017 and through the termination of the MSAs, Citizen and Linn maintained any drilling advances from joint interest partners. See *Note 12 Transactions with Affiliates* for discussion of the MSAs with Citizen and Linn.

Asset Retirement Obligation

The Company is obligated to fund the costs of disposing of long-lived assets upon their abandonment. The Company s asset retirement obligations (ARO) relate to the plugging of wells and the related abandonment of oil and natural gas properties. AROs are recognized as liabilities with an increase to the carrying amounts of the related assets when the obligation is incurred. The cost of the asset, including ARO, is depreciated over the useful life of the asset. Fair value of ARO is measured using the expected future cash outflows required to satisfy the retirement obligations discounted at the Company s credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value and the liability is settled or the well is sold, at which time the liability is removed. Accretion expense is included in accretion expense in the consolidated statements of operations.

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Cash and Cash Equivalents

The Company considers all highly liquid investments purchased with a maturity of three months or less and money market funds to be cash equivalents. The Company maintains its cash balances at credit-worthy financial institutions that are insured by the Federal Deposit Insurance Corporation (FDIC). At times, cash balances may be in excess of FDIC limits. The Company has not incurred any losses related to the amounts in excess of FDIC limits.

Accounts Receivable

Accounts receivable consists mainly of receivables from oil, natural gas and NGL purchasers and joint interest owners on properties the Company operates. Accounts receivable from the sale of oil, natural gas and NGLs are accrued based on estimates of the volumetric sales and prices the Company believes it will receive. The Company routinely reviews outstanding balances, assesses the financial strength of its purchasers and joint interest owners and records a reserve for amounts not expected to be fully recovered. The need for an allowance is determined based upon reviews of individual accounts, existing economic conditions and other pertinent factors. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. At December 31, 2018, the Company recorded an allowance for doubtful accounts of $3.3 million related to receivables from joint interest owners. The Company had no reserve for bad debts at December 31, 2017.

Deferred Financing Costs

Costs incurred in connection with the Company s debt are capitalized and amortized as interest expense over the scheduled maturity period. Unamortized costs are associated with the Company s revolving credit facility and are reflected as a component of long-term assets in the consolidated balance sheets.

Equity-Based Compensation

Equity-based compensation is measured based on the grant date fair value of the award and recognized over the requisite service period. For employees directly involved in exploration and development activities, equity compensation is capitalized to the Company s 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. The Company accounts for forfeitures of stock compensation as they occur. As of December 31, 2018, no forfeitures have occurred.

Earnings (Loss) per Share

The Company uses the treasury stock method to determine the potential dilutive effect of outstanding performance share units and restricted stock units. Refer to *Note 11 Equity Compensation* for details on the Company s performance share units and restricted stock units.

Income Taxes

The Company is a corporation and therefore a taxable entity. 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. As a result of the Reorganization, the Company recorded a deferred tax liability based on the change in its tax status.

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The Company recognizes deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period the rate change is enacted. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized. See *Note 13 Income Taxes* for further information on the Company s taxes.

The Company evaluates uncertain tax positions for recognition and measurement in the consolidated financial statements. To recognize a tax position, the Company determines whether it is more likely than not, based on technical merits, that the tax position will be sustained upon examination. Any interest or penalties would be recognized as a component of income tax expense.

Defined Contribution Plan

In 2018, the Company adopted a 401(k) retirement plan and health and welfare benefit plans in which our employees are eligible to participate. Under the 401(k) retirement plan, the Company provides for an employer match of employee contributions of up to 6% of eligible compensation and a profit-sharing contribution of up to 8% of eligible compensation. For the year ended December 31, 2018, the Company paid $1.2 million in contributions to the plan.

Comprehensive Income

The Company has no elements of comprehensive income other than net income.

Concentrations of Credit Risk

The Company sells oil, natural gas and NGLs to various types of customers. The future availability of a ready market for oil, natural gas and NGL depends on numerous factors outside the Company s control, none of which can be predicted with certainty. Additionally, limitations on capacity at processing plants could also impact the Company s ability to sell its oil, natural gas and NGLs. The Company is subject to credit risk resulting from the concentration of its oil, natural gas and NGL receivables with its significant purchasers. The Company does not believe the loss of any single purchaser would materially impact its results of operations because oil, natural gas and NGLs are fungible products with well-established markets and numerous purchasers.

For the years ended December 31, 2018, 2017, and 2016, the Company had the following major customers that exceeded 10% of total oil, natural gas and NGL revenues:

	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 Resources, Inc. (Riviera). See *Note 12 Transactions with Affiliates*.

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The Company s 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. The Company monitors on an ongoing basis the credit ratings of its derivative counterparties and considers its counterparties credit default risk ratings in determining the fair value of its derivative contracts. The Company s derivative contracts are with multiple counterparties to minimize its exposure to any individual counterparty. The counterparties to the Company s derivative contracts at December 31, 2018 are also lenders under its revolving credit facility. As a result, the Company does not require collateral or other security from counterparties nor is the Company required to post collateral to support derivative instruments. The Company has master netting agreements with all of its derivative counterparties, which allow the Company to net its derivative assets and liabilities with the same counterparty. As a result of the netting provisions, the Company s 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.

Commitments and Contingencies

The Company is subject to legal proceedings, claims, and liabilities that arise in the ordinary course of business. An accrual is recorded for a loss contingency when its occurrence is probable and damages can be reasonably estimated based on the anticipated most likely outcome or the minimum amount within a range of possible outcomes. The Company regularly reviews contingencies to determine the adequacy of its accruals and related disclosures. The amount of ultimate loss may differ from these estimates. Except for environmental contingencies acquired in a business combination, which are recorded at fair value, the Company accrues losses associated with environmental obligations when such losses are probable and can be reasonably estimated.

Risks and Uncertainties

Historically, the markets for oil, natural gas, and NGLs have experienced significant price fluctuations. Price fluctuations can result from variations in weather, regional levels of production, availability of transportation capacity, and various other factors. Increases or decreases in the prices the Company receives for its production could have a significant impact on the Company s future results of operations and reserve quantities.

A portion of the Company s oil and natural gas production may be interrupted, or shut in, from time to time for various reasons, including, but not limited to, as a result of accidents, weather conditions, the unavailability of gathering, processing, compression, transportation or refining facilities or equipment or field labor issues, or intentionally as a result of market conditions such as oil or natural gas prices that the Company deems uneconomic. If a substantial amount of the Company s production is interrupted or shut in, the Company s cash flows and, in turn, it s financial condition and results of operations could be materially and adversely affected.

Recently Issued Accounting Standards

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)* (ASC 606). This guidance supersedes most of the existing revenue recognition requirements in GAAP and requires (i) an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to in exchange for those goods or services and (ii) requires expanded disclosures regarding the nature, amount, timing and certainty of revenue and cash flows from contracts with customers. Subsequent to the issuance of ASU 2014-09, the FASB issued additional guidance to assist entities with implementation efforts, including the issuance of ASU 2016-08, *Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net)* (ASU 2016-08), pertaining to the presentation of revenues on a gross basis (revenues presented separately

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from associated expenses) versus a net basis. This guidance requires an entity to record revenue on a gross basis if it controls a promised good or service before transferring it to a customer, whereas an entity records revenue on a net basis if its role is to arrange for another entity to provide the goods or services to a customer. Applying the guidance in ASU 2016-08 requires significant judgment in determining the point in time when control of products transfers to customers. Effective January 1, 2018, the Company adopted ASC 606 using the modified retrospective method of transition under which the standard is applied only to the most current period presented. Accordingly, comparative information has not been adjusted and continues to be reported under the previous revenue standard. See *Note 3 Revenue from Contracts with Customers* for discussion of the impact upon adoption and the additional disclosures.

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. The Company enters into lease agreements to support its operations, such as office space, drilling rigs and field equipment. ASU 2016-02 will not impact the accounting or financial presentation of the Company s mineral leases.

The Company plans 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. The Company plans 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 does not plan to elect the practical expedient of hindsight when determining the lease term of existing contracts at the effective date. The Company also plans to elect the practical expedient under ASU 2018-01 *Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842* that allows it to not evaluate existing or expired land easements not previously accounted for as leases prior to the effective date. The Company is working to complete its evaluation of the impact of ASU 2016-02 on its 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. The Company currently plans 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.

Note 3 Revenue from Contracts with Customers

The Company adopted ASC 606 on January 1, 2018 using a modified retrospective approach, which only applies to contracts that were not completed as of the date of initial application. The adoption did not require an adjustment to opening retained earnings for the cumulative effect adjustment. The adoption does not have a

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material impact on the timing of the Company s revenue recognition or its financial position, results of operations, net income, or cash flows, but does impact the Company s presentation of revenues and expenses under the gross-versus-net presentation guidance in ASU 2016-08.

The following table shows the impact of the adoption of ASC 606 on the Company s current period results as compared to the previous revenue recognition standard, ASC Topic 605, *Revenue Recognition* (ASC 605):

	Year Ended December 31, 2018		
	Under ASC 606	Under ASC 605	Increase/ (decrease)
		(in thousands)	
Revenues			
Oil sales	$ 275,239	$ 275,399	$ (160)
Natural gas sales	$ 76,056	$ 96,086	$ (20,030)
Natural gas liquid sales	$ 88,472	$ 114,021	$ (25,549)
Operating expenses			
Gathering, transportation and processing	$	$ 45,739	$ (45,739)
Net loss	$ (140,671)	$ (140,671)	$

Oil Sales

Most of the Company s oil contracts transfer physical custody and title at or near the wellhead, which is commonly when control of the oil has been transferred to the purchaser. The Company s oil production is primarily sold under market-sensitive contracts that are typically priced at a differential to the NYMEX price. Any differentials incurred after the transfer of control of the oil are net against oil sales as they represent part of the transaction price of the contract. For its oil contracts, the Company generally records its sales based on the net amount received.

Natural Gas and NGL Sales

Most of the Company s natural gas is sold at the wellhead or inlet to the processor s facility, which is commonly when control of the natural gas has been transferred to the purchaser. The natural gas is sold under percentage of proceeds processing contracts. Under these contracts, the purchaser gathers the natural gas where it is produced and transports it via pipeline to natural gas processing plants where NGL products are extracted. The NGL products and remaining residue gas are then sold by the purchaser. Under the natural gas percentage of proceeds contracts, the Company receives a percentage of the value for the extracted NGLs and the residue gas.

For its natural gas processing contracts, the Company generally records its natural gas and NGL sales net of gathering, processing and transportation expenses based on a principal versus agent assessment for individual contracts.

Performance Obligations

The Company satisfies the performance obligations under its oil and natural gas sales contracts through delivery of its production and transfer of control to a customer. Upon delivery of production, the Company has the right to receive consideration from its customers in amounts that correspond with the value of the production transferred. The Company typically receives payment for oil, natural gas and NGL sales within 30 days of the month of delivery for operated properties and within 90 days of the month of delivery for non-operated properties.

The Company s oil sales contracts are short-term in nature with a contract term of one year or less. For those contracts, the Company utilized the practical expedient in ASC 606, which provides an exemption from

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disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

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

Contract Balances

The Company recognizes sales of oil, natural gas, and NGLs at a point in time when it satisfies a performance obligation and at that point the Company has an unconditional right to receive payment. Accordingly, these contracts do not give rise to contract assets or contract liabilities under ASC 606. The Company had accounts receivable related to revenue from contracts with customers of approximately $65.2 million as of December 31, 2018, which represent this unconditional right to receive payment.

Prior Period Performance Obligations

To record revenues for oil, natural gas and NGLs, the Company estimates the amount of production delivered at the end of each month and the prices expected to be received for those sales. Differences between estimated revenues and actual amounts received for all prior months are recorded in the month payment is received from the customer. For the year ended December 31, 2018, revenue recognized related to performance obligations satisfied in prior reporting periods was not material.

Note 4 Acquisitions

Linn Acquisition

As noted in *Note 1 Business and Organization*, in connection with the Contribution, Roan LLC acquired from Linn certain oil and natural gas properties located in Central Oklahoma (the Linn Acquisition). In exchange for the contributed oil and natural gas properties, Linn received a 50% equity interest in Roan LLC valued at approximately $1.3 billion based on the value of the business. Accordingly, the fair value of the Company was primarily comprised of the fair value of these contributed oil and natural gas properties. See *Note 10 Equity* for further discussion of the equity issued to Linn.

Because the Linn Acquisition was determined to be a business combination as the acquired oil and natural gas properties met the definition of a business, the acquired assets and liabilities were recorded at fair value as of August 31, 2017, the acquisition date. The following assumptions were used to determine the fair value of the oil and natural gas properties:

Discount rate	9.50%
Reserve risk factor [1]	35%-100%
Oil price	three years NYMEX WTI forward curve
Natural gas price	three years NYMEX Henry Hub forward curve
NGL price	39% of oil price
Price escalation [2]	2.00%

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(1) Possible reserves had a reserve risk factor of 35%, probable reserves had a reserve risk factor of 75%, and proved undeveloped reserves had a reserve risk factor of 90%.
(2) Prices were escalated at the end of the forward curve

The following table summarizes the purchase price and allocation of the fair values of assets acquired and liabilities assumed (in thousands):

Consideration given	
Equity units	$ 1,281,743
Allocation of purchase price	
Inventory	$ 205
Proved oil and natural gas properties	214,647
Unproved oil and natural gas properties	1,086,600
Total assets acquired	1,301,452
Asset retirement obligations	(7,547)
Revenue suspense	(12,162)
Total fair value of net assets acquired	$ 1,281,743

The following unaudited pro forma combined results of operations is provided for the years ended December 31, 2017 and 2016 as though the Linn Acquisition had been completed as of the earliest period presented at the time of the acquisition. The pro forma combined results of operations have been prepared by adjusting the historical results of the Company to include the historical results of the assets acquired in the Linn Acquisition.

These supplemental pro forma results of operations are provided for illustrative purposes only and do not purport to be indicative of the actual results that would have been achieved by the combined company for the periods presented or that may be achieved by the combined company in the future. The pro forma results of operations do not include any cost savings or other synergies that resulted, or may result, from the Linn Acquisition or any estimated costs incurred to integrate the Linn Acquisition.

	(Unaudited) **Years Ended December 31,**	
	2017	**2016**
	(in thousands)	
Revenue	$ 215,161	$ 90,238
Net income	$ 44,873	$ 26,378

Acquisitions of Unproved Properties

During the year ended December 31, 2017, the Company acquired, from unrelated third parties, interests in approximately 23,400 net acres of leasehold in separately negotiated transactions for aggregate cash consideration of $49.7 million, all of which were accounted for as asset acquisitions and recorded as additions to unproved oil and natural gas properties.

As discussed in *Note 12 Transactions with Affiliates*, Citizen and Linn acquired acreage during 2017 on behalf of Roan LLC for $63.0 million, which was included in accounts payable and accrued liabilities affiliates at December 31, 2017. In March 2018, Roan LLC paid Linn $22.9 million in cash and issued equity units to both Citizen and Linn to settle the amount due.

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Note 5 Oil and Natural Gas Properties

The Company s oil and natural gas properties are in the continental United States. The oil and natural gas properties include the following:

	December 31, 2018	December 31, 2017
	(in thousands)	
Oil and natural gas properties		
Proved	$ 1,538,379	$ 750,492
Unproved	1,089,954	1,126,459
Less: accumulated depreciation, depletion, amortization and impairment	(230,836)	(78,307)
Oil and natural gas properties, net	$ 2,397,497	$ 1,798,644

There were no exploratory well costs pending determination of proved reserves at December 31, 2018 or 2017 nor any unsuccessful exploratory dry hole costs during the years ended December 31, 2018 and 2016. During the year ended December 31, 2017, there was $1.3 million of pre-drilling costs associated with an exploratory dry hole that is included in exploration costs in the accompanying consolidated statements of operations.

Note 6 Asset Retirement Obligations

The following is a reconciliation of the changes in the Company s ARO for the years ended December 31, 2018 and 2017:

	Years Ended December 31, 2018	Years Ended December 31, 2017
	(in thousands)	
Asset retirement obligation, beginning balance	$ 10,769	$ 2,245
Liabilities incurred or acquired (1)	3,347	8,118
Revisions in estimated cash flows (2)	2,018	42
Liabilities settled	(139)	
Accretion expense	853	364
Asset retirement obligation, ending balance	**16,848**	**10,769**
Less: current portion of obligations	790	

Asset retirement obligation long term	**$ 16,058**	**$ 10,769**

(1) For the year ended December 31, 2017, liabilities incurred or acquired included $7.5 million assumed as part of the Linn Acquisition.
(2) For the year ended December 31, 2018, revisions primarily represent changes in the economic lives of producing properties and the Company s share of estimated costs.

Note 7 Long-Term Debt

In September 2017, the Company entered into a $750.0 million credit agreement with an initial borrowing base of $200.0 million and maturity on September 5, 2022 (as amended, the 2017 Credit Facility). In September 2018, the redetermination resulted in an increase to the borrowing base to $675.0 million. Redetermination of the borrowing base of the 2017 Credit Facility occurs semiannually on or about October 1 and April 1. As of

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December 31, 2018, the Company had $514.6 million of outstanding borrowings and no letters of credit outstanding under the 2017 Credit Facility. At December 31, 2018, the weighted average interest rate on borrowings under our 2017 Credit Facility was 5.21%. The 2017 Credit Facility is secured by substantially all of the assets of the Company.

The Company amended the 2017 Credit Facility in September 2018 to increase the borrowing base as noted above as well as to allow for permitted additional debt of up to $500 million before any reduction in the borrowing base would occur, to reduce the applicable margin for both London Interbank Offered Rate (LIBOR) and alternate base rate (ABR) loans by 0.25% for each utilization level, and to reduce the commitment fee rate for the two lowest utilization levels to 0.375%.

Principal maturities of the Company s borrowings at December 31, 2018, consisting of amounts outstanding under the 2017 Credit Facility, are as follows (in thousands):

2019	$
2020	
2021	
2022	514,639
	$ 514,639

Amounts borrowed under the 2017 Credit Facility bear interest at LIBOR or the ABR at the Company s 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, based on the utilization percentage of the 2017 Credit Facility. Additionally, the 2017 Credit Facility provides for a commitment fee, which is payable at the end of each calendar quarter. The pricing grid below shows the applicable margin for LIBOR rate or ABR loans as well as the commitment fee depending on the Utilization Level (as defined in the credit agreement):

Utilization Level	Utilization	LIBOR Margin	ABR Margin	Commitment Fee
Level I	<25%	2.00%	1.00%	0.375%
Level II	>25% but <50%	2.25%	1.25%	0.375%
Level III	>50% but <75%	2.50%	1.50%	0.500%
Level IV	>75% but <90%	2.75%	1.75%	0.500%
Level V	>90%	3.00%	2.00%	0.500%

The 2017 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, the Company is prohibited from hedging in excess of

(a) 80% of reasonably anticipated projected production for the first thirty (30) month rolling period (based upon the Company s 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, the Company is 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 its most recent reserve report.

The 2017 Credit Facility also contains financial covenants requiring the Company to comply with a leverage ratio of the Company s consolidated debt to consolidated EBITDAX (as defined in the credit agreement) for the

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period of four fiscal quarters then ended of not more than 4.00 to 1.00 and a current ratio of the Company s 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, the Company was in compliance with the covenants under the 2017 Credit Facility.

Prior to the 2017 Credit Facility, Citizen had a two-year, $500.0 million credit facility (Citizen 2017 Credit Facility) with an initial borrowing base of $82.5 million. In August 2017, the Citizen 2017 Credit Facility was terminated and the outstanding balance of $20.3 million was repaid.

Note 8 Derivative Instruments

The Company utilizes fixed price swaps and basis swaps to manage the price risk associated with the sale of its oil, natural gas and NGL 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, the Panhandle Eastern Pipeline or Natural Gas Pipeline Company of America Mid-Continent. When the referenced settlement price is less than the price specified in the contract, the Company receives an amount from the counterparty based on the price difference multiplied by the volume. Similarly, when the referenced settlement price exceeds the price specified in the contract, the Company pays the counterparty an amount based on the price difference multiplied by the volume.

The following table reflects the Company s open commodity contracts at December 31, 2018:

	2019	2020	Total
Oil fixed price 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

The Company nets the fair value of derivative instruments by counterparty in the accompanying consolidated balance sheets where the right to offset exists. See *Note 9 Fair Value Measurements* for further information regarding the fair value measurement of the Company s derivatives.

As the Company has elected to not account for commodity derivative instruments as hedging instruments, gains or losses resulting from the change in fair value along with the gains or losses resulting in settlement of derivative contracts are reflected in gain (loss) on derivative contracts included in the consolidated statement of operations.

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The following table presents the Company s gain (loss) on derivative contracts and net cash (paid) received upon settlement of its derivative contracts for the years ended December 31, 2018 and 2017:

	Years Ended December 31, 2018	2017
	(in thousands)	
Gain (loss) on derivative contracts	$ 78,054	$ (6,797)
Net cash (paid) received upon settlement of derivative contracts (1)	$ (33,279)	$ 2,705

(1) Includes $1.3 million of cash received upon settlement of derivative contracts prior to their contractual maturity for the year ended December 31, 2017.

There were no gains or losses on derivative contracts in the year ended December 31, 2016 and no derivative contracts outstanding as of December 31, 2016.

Note 9 Fair Value Measurements

Assets and liabilities that are measured at fair value are classified based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values, stated below, considers the market for the Company s financial assets and liabilities, the associated credit risk and other factors. The Company considers active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The Company s recurring fair value measurements are performed for its commodity derivatives.

Commodity Derivative Instruments

Commodity derivative contracts are stated at fair value in the accompanying consolidated balance sheets. The Company adjusts the valuations from the valuation model for nonperformance risk and for counterparty risk. The fair values of the Company s commodity derivative instruments are classified as Level 2 measurements as they 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.

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The following table presents the amounts and classifications of the Company s derivative assets and liabilities as of December 31, 2018 and 2017, as well as the potential effect of netting arrangements on contracts with the same counterparty (in thousands):

	December 31, 2018					
	Level 1	Level 2	Level 3	Gross Fair Value	Netting	Carrying Value
Assets						
Current commodity derivatives	$	$ 85,728	$	$ 85,728	$ (3,548)	$ 82,180
Noncurrent commodity derivatives		21,565		21,565	(927)	20,638
Total assets	**$**	**$ 107,293**	**$**	**$ 107,293**	**$ (4,475)**	**$ 102,818**
Liabilities						
Current commodity derivatives	$	$ (4,393)	$	$ (4,393)	$ 3,548	$ (845)
Noncurrent commodity derivatives		(1,068)		(1,068)	927	(141)
Total liabilities	**$**	**$ (5,461)**	**$**	**$ (5,461)**	**$ 4,475**	**$ (986)**

	December 31, 2017					
	Level 1	Level 2	Level 3	Gross Fair Value	Netting	Carrying Value
Assets						
Current commodity derivatives	$	$ 2,856	$	$ 2,856	$ (2,704)	$ 152
Noncurrent commodity derivatives		2,182		2,182	(1,186)	996
Total assets	**$**	**$ 5,038**	**$**	**$ 5,038**	**$ (3,890)**	**$ 1,148**
Liabilities						
Current commodity derivatives	$	$ (11,983)	$	$ (11,983)	$ 2,704	$ (9,279)
Noncurrent commodity derivatives		(2,557)		(2,557)	1,186	(1,371)
Total liabilities	**$**	**$ (14,540)**	**$**	**$ (14,540)**	**$ 3,890**	**$ (10,650)**

Non-Recurring Fair Value Measurements

The Company utilizes fair value on a non-recurring basis to review its proved oil and natural gas properties for potential impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such property. The Company uses an income approach analysis based on management s estimated net discounted future cash-flows of proved property. Unobservable inputs included estimates of oil and natural gas production, as the case may be, from the Company s reserve reports, commodity prices based on the sales contract terms or forward price curves, operating and development costs, and a discount rate based on a market-based weighted average cost of capital (all of which are Level 3 inputs within the fair value hierarchy).

The Company s non-recurring fair value measurements include the purchase price allocations for the fair value of assets and liabilities acquired through business combinations and the determination of the grant date fair value of the Company s performance share units. The fair value of assets and liabilities acquired through business combinations is calculated using a discounted-cash flow approach using level 3 inputs. The fair value of assets or liabilities associated with purchase price allocations is on a non-recurring basis and is not measured in periods after initial recognition. The grant date fair value of the Company s performance share units is determined using a Monte Carlo simulation model and is classified as a Level 3 measurement. Please refer to *Note 4 Acquisitions* and *Note 11 Equity Compensation* for additional discussion.

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Other Financial Instruments

The Company s financial instruments, not otherwise recorded at fair value, consist primarily of cash, trade receivables, trade payables, and long-term debt. The carrying values of cash and cash equivalents, accounts payable, revenue payable, and accounts receivable approximate fair values due to the short-term maturities of these instruments and the carrying value of long-term debt approximates fair value as the applicable interest rates are variable and reflective of market rates.

Note 10 Equity

In September 2018 and in conjunction with the Reorganization, the Company issued 152.5 million shares of its Class A common stock to the members of Roan LLC in exchange for their equity interest in Roan LLC. The Reorganization was accounted for as a reverse recapitalization with Roan Inc. as the accounting acquirer and therefore did not result in any change in the accounting basis for the underlying assets. Net income before taxes and equity-based compensation were allocated ratably to the members of Roan LLC and the stockholders of Roan Inc. for the period before and after the Reorganization, respectively. For comparative purposes, the issuance of the shares to the members of Roan LLC at the time of the Reorganization was reflected on a retroactive basis with the units outstanding during each period presented.

For the period of September 1, 2017 through the date of the Reorganization, Roan LLC was governed by the Amended and Restated Limited Liability Company Agreement of Roan Resources LLC. In connection with the Contribution in August 2017, Roan LLC issued 1.5 billion membership units representing capital interests in Roan LLC (the LLC Units) for a 50% equity interest in Roan LLC, to Linn in exchange for the contribution of oil and natural gas properties. See *Note 4 Acquisitions* for additional discussion of the Linn Acquisition. Additionally, Roan LLC issued 1.5 billion LLC Units, which represented a 50% equity interest in Roan LLC, to Citizen in exchange for the contribution of oil and natural gas properties. The fair value of the LLC Units issued to Citizen was the same as that of the LLC Units issued to Linn.

As discussed in *Note 4 Acquisitions*, Citizen and Linn acquired acreage during 2017 on Roan LLC s behalf. In March 2018, Roan LLC issued 19.2 million LLC Units to each Citizen and Linn for the additional leasehold acreage.

For the period January 1, 2017 through August 31, 2017, Citizen s operations were governed by the provisions of the Citizen Amended and Restated Operating Agreement (the Citizen Operating Agreement), effective February 29, 2016, and Citizen had two classes of membership interests outstanding, Class A and Class B interests. Class A interests represented capital interests in Citizen and Class B interests represented interests in profits, losses and distributions. Distributions were made to the Class A interests and Class B interests members pro rata in accordance with their membership interests; however, once the Class A interests members received an internal rate of return threshold of 9% prior to distributions to any other class of interest, the Class B interests members received a percentage of distributions in excess of their membership interests based on the terms of the Citizen Operating Agreement.

Note 11 Equity Compensation

The Company has adopted the Roan Resources, Inc. Amended and Restated Management Incentive Plan (the Plan), which provides for grants of options, stock appreciation rights, restricted stock unit, stock awards, dividend equivalents, other stock-based awards, cash awards and substitute awards.

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Performance Share Units

Prior to the Reorganization, Roan LLC granted performance share units to certain of its employees under the Roan LLC Management Incentive Plan. The performance share units were converted into awards of performance share units under the Plan, hereafter referred to as the PSUs, and are subject to the terms of the Plan and individual award agreements. The amount of PSUs that can be earned range from 0% to 200% based on the Company s market value on December 31, 2020 (Performance Period End Date). The Company s market value on the Performance Period End Date will be determined by reference to the volume-weighted average price of the Company s Class A common stock for the 30 consecutive trading days immediately preceding the Performance Period End Date. Each earned PSU will be settled through the issuance of one share of the Company s Class A common stock. Other than the security in which the PSUs are settled, no terms of the PSUs were modified in connection with the conversion of the PSUs.

The following table presents activity for the Company s PSUs during the years ended December 31, 2018 and 2017.

	Number of PSUs	Weighted Average Fair Value	Total Fair Value ($ in thousands)
Outstanding at December 31, 2016		**$**	**$**
Granted	16,350,000	1.41	23,054
Vested			
Outstanding at December 31, 2017	**16,350,000**	**$ 1.41**	**$ 23,054**
Granted	6,825,000	1.88	12,810
Vested			
Conversion (1)	(22,016,250)		
Outstanding at December 31, 2018	**1,158,750**	**$ 30.95**	**$ 35,864**

(1) PSUs were converted on a basis of 0.05 to 1.0. There was no change to the deemed fair value of the awards based on assessment of modification.

Compensation expense associated with the PSUs for the years ended December 31, 2018 and 2017 was $11.0 million and $0.4 million, respectively, and is included in general and administrative expenses on the accompanying consolidated statements of operations. There was no such expense during the year ended December 31, 2016. Unrecognized expense as of December 31, 2018 for all outstanding PSU awards was $24.4 million, which will be recognized over a weighted-average remaining period of 2.0 years. Under the treasury stock method, the PSUs are antidilutive for the weighted average share calculation and therefore are excluded from dilutive weighted average shares in the accompanying consolidated statements of operations.

The grant date fair value of the PSUs was determined using a Monte Carlo simulation model, which results in an estimated percentage of performance share units earned and estimated Company value on the Performance Period End Date. The grant date fair value of the PSUs is expensed on a straight-line basis from the grant date to the Performance Period End Date.

The following table shows the range of assumptions that were used for the Monte Carlo simulation model to determine the grant date fair value and associated compensation expense for the PSUs granted during the year ended December 31, 2018:

Company enterprise value (in billions)	$ 4.19	$4.56
Equity volatility	34.0%	36.0%
Weighted average risk-free interest rate	1.96%	2.54%

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Restricted Stock Units

Under the Plan, the Company is authorized to issue restricted stock and restricted stock units to eligible employees. The Company estimates the fair values of restricted stock awards and units as the closing price of the Company s common stock on the grant date of the award, which is expensed over the applicable vesting period.

The following table presents activity for the Company s restricted stock units during the year ended December 31, 2018:

	Number of Restricted Stock Units	Weighted Average Fair Value	Total Fair Value ($ in thousands)
Outstanding at December 31, 2017		$	$
Granted	11,800	16.95	200
Vested			
Forfeited			
Outstanding at December 31, 2018	**11,800**	**$ 16.95**	**$ 200**

Compensation expense associated with the restricted stock units for the year ended December 31, 2018 was $0.03 million and is included in general and administrative expenses on the accompanying consolidated statements of operations. There were no restricted stock units issued prior to 2018. As of December 31, 2018, the Company s unrecognized compensation cost related to unvested restricted stock units was $0.2 million, which will be recognized over a weighted-average remaining period of 0.9 year. Under the treasury stock method, the restricted stock units are antidilutive for the weighted average share calculation and therefore are excluded from dilutive weighted average shares in the accompanying consolidated statements of operations.

Note 12 Transactions with Affiliates

Management Service Agreements

Under the MSAs, Citizen and Linn provided certain services in respect to the oil and natural gas properties they contributed to the Company. Such services included serving as operator of the oil and natural gas properties contributed, land administration, marketing, information technology and accounting services. As a result of Citizen and Linn continuing to serve as operator of the contributed assets and contracting directly with vendors for goods and services for operations, Citizen and Linn collected amounts due from joint interest owners for their share of costs and billed the Company for its share of costs. The services provided under the MSAs ended in April 2018 when the Company took over as operator for the oil and natural gas properties contributed by Citizen and Linn. In conjunction with the conclusion of the MSAs in April 2018, the Company assumed certain working capital accounts associated with the properties contributed from Citizen and Linn.

For each of the years ended December 31, 2018 and 2017, the Company incurred approximately $10.0 million for charges related to the services provided under the MSAs, which are recorded in general and administrative expenses in the accompanying consolidated statements of operations.

Through April 2018, Citizen and Linn billed the Company for its share of operating costs in accordance with the MSAs. At December 31, 2017, the Company had $55.5 million and $46.5 million due to Linn and Citizen, respectively, included in accounts payable and accrued liabilities affiliates in the accompanying consolidated balance sheets. At December 31, 2017, the Company had $19.0 million due to Linn and Citizen for revenue suspense associated with the oil and natural gas properties contributed to the Company included in accounts payable and accrued liabilities affiliates in the accompanying consolidated balance sheets.

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Acquisition of Acreage

As provided for in the Contribution Agreement, Citizen and Linn acquired additional acreage within an area of mutual interest on behalf of the Company. As of December 31, 2017, the additional acreage acquired totaled $63.0 million and the Company reflected the amount due to Citizen and Linn in accounts payable and accrued liabilities affiliates. See *Note 4 Acquisitions* and *Note 10 Equity* for further discussion of the settlement of the payable due to Citizen and Linn related to the additional acquired acreage.

Natural Gas Dedication Agreement

The Company has a gas dedication agreement with Blue Mountain, a subsidiary of Riviera, which has directors and shareholders in common with the Company. Amounts due from Blue Mountain at December 31, 2018 and 2017 are reflected as accounts receivable affiliates in the accompanying consolidated balance sheets and represent accrued revenue for the Company s portion of the production sold to Blue Mountain. Sales to Blue Mountain are reflected as natural gas sales affiliates and NGL sales affiliates in the accompanying consolidated statements of operations. See further discussion of this gas dedication agreement in *Note 14 Commitments and Contingencies*.

Corporate Office Lease

During 2018, the Company entered into a lease for office space in Oklahoma City, Oklahoma that is owned by a subsidiary of Riviera under a lease with an initial term of 5 years with an option to extend the lease for an additional 5 years at the end of the initial term. The Company paid $0.5 million during the year ended December 31, 2018 under this lease. Total remaining payments under the lease are $8.1 million.

Reorganization Transactions

In conjunction with the Reorganization, the Company entered into a tax matters agreement (TMA) with Riviera. See *Note 13 Income Taxes* for further discussion of the TMA and the related payable to Riviera.

Also in conjunction with the Reorganization, the Company paid certain legal costs incurred by Riviera on the Company s behalf. These costs totaled $1.8 million and were included in general and administrative expenses in the accompanying consolidated statement of operations for the year ended December 31, 2018.

Consulting Services

Atlas, LLC (Atlas) provided the Company supervisory services throughout drilling and completion operations. Atlas is wholly owned jointly by a director and an employee of Citizen. For the year ended December 31, 2017, the Company incurred $2.3 million in charges related to services provided which are recorded within oil and natural gas properties, successful efforts on the accompanying consolidated balance sheet. As of December 31, 2017, the Company had no amounts payable to Atlas. There were no such services provided by Atlas to the Company during the year ended December 31, 2018.

Note 13 Income Taxes

As discussed in *Note 1 Business and Organization*, the Company was formed in September 2018 in connection with the Reorganization. The Company s 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.

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A deferred tax liability was recorded as a result of the Reorganization based on the Company becoming a corporation that is a taxable entity under the Internal Revenue Code of 1986, as amended (the Code). The initial recording of the deferred tax liability recognized by the Company as a result of the Reorganization was reflected in income tax expense based on the deferred tax liability resulting from the change in tax status. Due to the nontaxable nature of the Reorganization, there were no adjustments to the tax basis or other tax attributes in the measurement of the deferred taxes except to the extent any gain was recognized by the other parties to the Reorganization.

The Company s effective combined U.S. federal and state income tax rate for the year ended December 31, 2018 excluding discrete items was 24.3%. During the year ended December 31, 2018, the Company recognized income tax expense of $356.9 million, including $304.5 million related to the initial recording of the deferred tax liability recognized by the Company as a result of the Reorganization.

In conjunction with the Reorganization, the Company entered into the TMA with Riviera. The TMA, in part, provides for the indemnification of the Company and the entitlement of Riviera to refunds related to certain taxes of Linn Energy, Inc. prior to the spinoff of assets from Linn Energy, Inc. to Riviera. As a result of the TMA and an estimated overpayment of federal taxes by Linn Energy, Inc. received by the Company, the Company recorded a payable of $7.6 million to Riviera at December 31, 2018. The payable is included in accounts payable and accrued liabilities affiliates in the accompanying consolidated balance sheets.

At December 31, 2018, the Company did not have any significant uncertain tax positions requiring recognition in the financial statements. The tax year for 2018 remains subject to examination by the major tax jurisdictions.

The components of the Company s provision for income taxes for the year ended December 31, 2018 are as follows (in thousands):

Current income tax expense	
Federal	$
State	
Deferred income tax expense	
Federal	277,794
State	79,068
	356,862
Provision for income taxes	$ 356,862

The Company s deferred tax assets and liabilities as of December 31, 2018 include the following (in thousands):

Deferred income tax assets	
Net operating losses	$ 42,013
Other	4,409
	46,422
Deferred income tax liabilities	
Oil and natural gas properties	(377,362)
Derivative contracts	(25,922)
	(403,284)
Deferred tax liabilities, net	$ (356,862)

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The following is a reconciliation, stated as a percentage of pretax income, of the United States statutory federal income tax rate to the Company s effective tax rate for the year ended December 31, 2018:

	Amount	Percent
	(in thousands)	
Income (loss) at U.S. federal statutory rate	$ 45,400	21.0%
Net effect of state income taxes	9,173	4.2%
Change in tax status	304,455	140.8%
Other	(2,166)	(1.0)%
Income tax provision / Effective rate	$ 356,862	165.0%

As of December 31, 2018, the Company has federal and Oklahoma net operating loss carryforwards for both jurisdictions of $165.0 million, which do not expire.

Note 14 Commitments and Contingencies

Commitments

The following table presents the future minimum payments under noncancelable operating leases and other commitments as of December 31, 2018 (in thousands):

	2019	2020	2021	2022	2023	Thereafter	Total
Office building leases	$ 1,692	$ 2,047	$ 2,136	$ 2,229	$ 456	$ 171	$ 8,731
Pipe and equipment purchase commitments (1)	1,455						1,455
Drilling rig commitments (2)	15,352						15,352
Total	$ 18,499	$ 2,047	$ 2,136	$ 2,229	$ 456	$ 171	$ 25,538

(1) Reflects commitments to purchase specified amounts of pipe and equipment.
(2) Reflects future minimum drilling fees including early termination fees as specified by the contract.

Office building leases

The Company leases its corporate office space in Oklahoma City, Oklahoma from a subsidiary of Riviera. This lease began in 2018 and expires in 2023. The Company leases additional office space from unrelated third parties for its field locations in Oklahoma.

Rent expense with respect to these lease commitments was approximately $1.4 million for the year ended December 31, 2018.

Drilling Contracts

As of December 31, 2018, the Company had entered into drilling rig contracts with various third parties in the ordinary course of business to ensure rig availability to complete the Company s drilling projects. These commitments are not recorded in the accompanying consolidated balance sheets.

Purchase Commitments

As of December 31, 2018, the Company had entered into pipeline and equipment purchase commitments with various third parties in the ordinary course of business to purchase specified amounts of pipe and equipment. These commitments are not recorded in the accompanying consolidated balance sheets.

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Notes to Consolidated Financial Statements

Litigation

In the ordinary course of business, the Company may at times be subject to claims and legal actions. Management believes it is remote that the impact of such matters will have a material adverse effect on the Company s financial position, results of operations or cash flows.

Environmental Matters

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and to comply with regulatory policies and procedures. At December 31, 2018 and 2017, the Company had no environmental matters requiring specific disclosure or requiring the recognition of a liability.

Natural Gas Dedication Agreements

The Company has dedicated its natural gas production from the oil and natural gas properties contributed by Citizen under an agreement with a third party. Under this dedication agreement, the Company is required to deliver its 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, the Company assumed Linn s dedication agreement with Blue Mountain. The agreement with Blue Mountain requires the Company to deliver its 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

Under an agreement with a third party, the Company has a requirement to deliver a minimum volume of natural gas from a specified area, as defined in the agreement. In the event that the Company is unable to meet this natural gas volume delivery commitment, it would incur deficiency fees on any undelivered volumes as of November 2021. If the Company is unable to deliver any natural gas volumes subsequent to December 31, 2018 through November 2021, it will owe deficiency fees of $8.1 million at the end of the commitment period.

Note 15 Subsequent Events

In January 2019, the Company entered into a water management services agreement with Blue Mountain. Under this agreement, Blue Mountain will provide water management services including pipeline gathering, disposal, treatment and redelivery of recycled water. The agreement provides for an acreage dedication for water management services through January 2029.

In March 2019, the Company amended its 2017 Credit Facility to, among other things, increase its borrowing base to $750 million.

Subsequent to December 31, 2018, the Company entered into fixed price swaps of 40,000 MMBtu per day of natural gas production at a weighted average price of $2.68 for the period of October 2020 through December 2020 and for 2,000 Bbls per day of oil production at a weighted average price of $57.80 for the period of January 2020 through December 2020.

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Note 16. Supplemental Information on Oil and Natural Gas Operations (Unaudited)

The following disclosures provide supplemental unaudited information regarding the Company s oil, natural gas and NGL activities, which were entirely within the United States.

Capitalized Costs Relating to Oil, Natural Gas and NGL Producing Activities

Aggregate capitalized costs related to oil and natural gas production activities with applicable accumulated depreciation, depletion, amortization and impairment are as follows:

	December 31, 2018	December 31, 2017
	(in thousands)	
Oil and natural gas properties		
Proved properties	$ 1,538,379	$ 750,492
Unproved properties	1,089,954	1,126,459
Total oil and natural gas properties	2,628,333	1,876,951
Accumulated depreciation, depletion, amortization and impairment	(230,836)	(78,307)
Oil and natural gas properties, net	$ 2,397,497	$ 1,798,644

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development

Costs incurred in oil, natural gas and NGL property acquisition, exploration and development activities are summarized as follows:

	December 31, 2018	December 31, 2017	December 31, 2016
		(in thousands)	
Acquisition costs of properties			
Proved properties	$ 5,655	$ 214,647	$ 1,079
Unproved properties	42,738	1,018,978	93,705
Development costs	719,198	390,991	152,284
Exploratory [(1)]	7,257	8,538	
Total costs incurred	$ 774,848	$ 1,633,154	$ 247,068

(1) Includes seismic costs.

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Results of Operations for Oil, Natural Gas and NGL Producing Activities

The following table sets forth the Company s results of operations for oil, natural gas and NGL producing activities for the years ended December 31, 2018, 2017 and 2016:

	Years Ended December 31,		
	2018	**2017**	**2016**
		(in thousands)	
Oil, natural gas and NGL sales	$ 439,767	$ 166,385	$ 54,965
Production expenses	47,600	16,872	5,090
Production taxes	17,579	3,685	1,087
Exploration expenses	43,303	28,154	
Gathering, transportation and processing (1)		18,602	5,920
Depreciation, depletion, amortization, and accretion	123,062	37,376	24,996
Impairment		4,475	5,258
Income tax expense (2)	13,103		
Results of operations	$ 195,120	$ 57,221	$ 12,614

(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.

(2) Income tax expense is calculated using results from the period after the Reorganization when the Company became a taxable entity and the Company s effective tax rate of 24.3%.

Oil, Natural Gas and NGL Reserves

Proved reserves were estimated in accordance with guidelines established by the SEC, which require that reserve estimates be prepared under existing economic and operating conditions based upon the 12-month unweighted average of the first day of the month prices. Proved reserves are estimated volumes of oil, natural gas, and NGLs that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions. There are numerous uncertainties inherent

Roan Resources, Inc.

Notes to Consolidated Financial Statements

in estimating quantities of proved reserves, and projecting future production rates and timing of future development costs. The following table sets forth proved reserves during the periods indicated:

	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (MBoe)
Proved reserves at December 31, 2015	387	8,517	678	2,484
Purchases of reserves	22	333	33	111
Extensions and discoveries	2,632	33,218	2,956	11,124
Revisions of previous estimates	598	4,145	398	1,687
Production	(740)	(6,382)	(546)	(2,350)
Proved reserves at December 31, 2016	2,900	39,831	3,519	13,057
Purchases of reserves	9,843	163,638	16,870	53,986
Extensions and discoveries	30,554	486,510	61,599	173,238
Revisions of previous estimates	(3,583)	20,844	(260)	(369)
Production	(2,294)	(24,953)	(2,150)	(8,603)
Proved reserves at December 31, 2017	37,420	685,869	79,578	231,309
Purchases of reserves				
Extensions and discoveries	34,714	451,750	48,791	158,797
Revisions of previous estimates	(12,087)	(184,547)	(25,365)	(68,209)
Production	(4,364)	(41,890)	(4,592)	(15,938)
Proved reserves at December 31, 2018	55,683	911,182	98,412	305,959

At December 31, 2018, the Company had approximately 305,959 MBoe of proved reserves. During 2018, the Company drilled 214 gross wells. This continued development of the Company s acreage and the drilling activity of other operators in the area with consideration of the Company s development plan resulted in extensions and discoveries of 158,797 MBoe. Revisions of previous estimates for the year ended December 31, 2018 reflect downward revisions of 33,342 MBoe associated with production performance and downward revisions of 36,038 MBoe that resulted from reworking of the Company s development plan, primarily driven by changes in wellbore lateral length and well density. The Company s current development plan reflects allocation of capital with a focus on efficiencies, recoveries and rates of return. The impact of pricing on revisions of previous estimates was minimal.

At December 31, 2017, the Company had approximately 231,309 MBoe of proved reserves. During 2017, the Company acquired unproved leasehold acreage and drilled 93 gross wells. The Company s drilling activity and the drilling activity of other operators in the area resulted in extensions and discoveries of 173,238 MBoe. Purchase of reserves of 53,986 MBoe reflects the reserves acquired in the Linn Acquisition. Revisions of previous estimates reflects upward revisions associated with increases in pricing of 3,277 MBoe, offset by downward revisions associated with performance of 3,646 MBoe. The purchase of reserves and extensions and discoveries were the primary drivers in the increase in reserves from December 31, 2016 to December 31, 2017.

At December 31, 2016, the Company had approximately 13,057 MBoe of proved reserves. During 2016, Citizen acquired approximately 62,500 net acres of unproved leasehold. Citizen s drilling of 55 gross wells and the drilling activity of other operators in the area resulted in extensions and discoveries of 11,124 MBoe. Additionally, the Company had additions to reserves during 2016 of 111 MBoe from purchase of reserves and 1,687 MBoe as a result of revisions of previous estimates due to well performance. Extensions and discoveries were the primary driver in the increase in proved reserves from December 31, 2015 to December 31, 2016.

Roan Resources, Inc.

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The following reserve information sets forth the estimated quantities of proved developed and proved undeveloped (PUD) oil, natural gas and NGL reserves of the Company as of December 31, 2018, 2017, and 2016:

	December 31,		
	2018	**2017**	**2016**
Proved Developed Reserves			
Oil (MBbls)	18,652	12,352	2,900
Natural gas (MMcf)	369,677	259,193	39,831
NGL (MBbls)	39,927	24,034	3,519
Total (MBoe)	120,192	79,585	13,057
Proved Undeveloped Reserves			
Oil (MBbls)	37,031	25,068	
Natural gas (MMcf)	541,505	426,676	
NGL (MBbls)	58,485	55,544	
Total (MBoe)	185,767	151,724	
Total Proved Reserves			
Oil (MBbls)	55,683	37,420	2,900
Natural gas (MMcf)	911,182	685,869	39,831
NGL (MBbls)	98,412	79,578	3,519
Total (MBoe)	305,959	231,309	13,057

In accordance with SEC regulations, the Company uses the 12-month average price calculated as the unweighted arithmetic average of the spot price on the first day of each month within the 12-month period prior to the end of the reporting period. The oil and natural gas prices used in computing the Company s reserves as of December 31, 2018, 2017, and 2016 were $65.66, $51.34, and $42.64 per barrel of oil, respectively, $3.16, $2.98, and $2.48 per MMBtu of natural gas, respectively. The NGL prices used in computing the Company s reserves as of December 31, 2018, 2017, and 2016 were $20.35, $19.00, and $15.26 per barrel, respectively.

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. All estimates of proved reserves are determined according to the rules prescribed by the SEC in existence at the time estimates were made. These rules require that the standard of reasonable certainty be applied to proved reserve estimates, which is defined as having a high degree of confidence that the quantities will be recovered. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as more technical and economic data becomes available, a positive or upward revision or no revision is much more likely than a negative or downward revision. Estimates are subject to revision based upon a number of factors, including many factors beyond the Company s control such as reservoir performance, prices, economic conditions, and government restrictions. In addition, results of drilling, testing, and production subsequent to the date of an estimate may justify revision of that estimate.

Reserve estimates are often different from the quantities of oil, natural gas, and NGLs that are ultimately recovered. Estimating quantities of proved oil, natural gas and NGL reserves is a complex process that involves significant interpretations and assumptions and cannot be measured in an exact manner. It requires interpretations and judgment of available technical data, including the evaluation of available geological, geophysical and

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Roan Resources, Inc.

Notes to Consolidated Financial Statements

engineering data. The accuracy of any reserve estimate is highly dependent on the quality of available data, the accuracy of the assumptions on which they are based upon, economic factors, such as oil, natural gas and NGL prices, production costs, severance and excise taxes, capital expenditures, workover and remedial costs, and the assumed effects of governmental regulation. In addition, due to the lack of substantial, if any, production data, there are greater uncertainties in estimating PUD reserves, proved developed non-producing reserves and proved developed reserves that are early in their production life. As a result, the Company s reserve estimates are inherently imprecise.

The meaningfulness of reserve estimates is highly dependent on the accuracy of the assumptions on which they were based. In general, the volume of production from oil and natural gas properties the Company owns declines as reserves are depleted. Except to the extent the Company conducts successful exploration and development activities or acquires additional properties containing proved reserves, or both, the Company s proved reserves will decline as reserves are produced.

Standardized Measure of Discounted Future Net Cash Flows

The following summary sets forth the Company s standardized measure of discounted future net cash flows relating from its proved oil, natural gas and NGL reserves.

	December 31, 2018	2017	2016
		(in thousands)	
Future cash inflows	$ 7,325,386	$ 5,270,465	$ 271,428
Future production costs	(1,773,779)	(1,664,724)	(102,817)
Future development costs	(1,294,565)	(745,769)	
Future income tax expense (1)	(797,247)		
Future net cash flows	3,459,795	2,859,972	168,611
Discount to present value at 10% annual rate	(1,760,094)	(1,664,303)	(50,339)
Standardized measure of discounted future net cash flows	$ 1,699,701	$ 1,195,669	$ 118,272

(1) Roan Inc. is a corporation, and as a result, is subject to U.S. federal, state and local income taxes. Our accounting predecessor, Roan LLC, passed through its taxable income to its owners for income tax purposes and thus was not subject to U.S. federal or state income taxes.

Roan Resources, Inc.

Notes to Consolidated Financial Statements

Principal changes in the standardized measure of discounted future net cash flows attributable to the Company s proved reserves are as follows:

	Years Ended December 31, 2018	2017	2016
		(in thousands)	
Standardized measure of discounted future net cash flows at the beginning of the period	$ 1,195,669	$ 118,272	$ 18,910
Sales of oil and natural gas, net of production costs	(374,588)	(124,526)	(42,868)
Acquisition of reserves		279,026	462
Extensions and discoveries, net of future development costs	1,126,713	877,846	104,581
Previously estimated development costs incurred during the period	124,822	148,505	
Net changes in prices and production costs	172,928	36,233	18,256
Changes in estimated future development costs	(13,160)	(17,970)	
Revisions of previous quantity estimates	(281,054)	(5,676)	15,573
Accretion of discount	119,567	11,827	1,891
Net change in income taxes (1)	(391,808)		
Net changes in timing of production and other	20,612	(127,868)	1,467
Standardized measure of discounted future net cash flows at the end of the period	$ 1,699,701	$ 1,195,669	$ 118,272

(1) Roan Inc. is a corporation, and as a result, is subject to U.S. federal, state and local income taxes. Our accounting predecessor, Roan LLC, passed through its taxable income to its owners for income tax purposes and thus was not subject to U.S. federal or state income taxes.

Note 17. Quarterly Financial Data (Unaudited)

The Company s unaudited quarterly financial data for 2018 and 2017 is summarized below.

	2018 First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts)			

Total revenues	$ 91,356	$ 35,965	$ 83,448	$ 307,052
Income (loss) from operations	$ 36,880	$ (21,670)	$ 514	$ 208,819
Net income (loss)	$ 35,081	$ (22,757)	$ (301,240)	$ 148,245
Earnings (loss) per share				
Basic	$ 0.23	$ (0.15)	$ (1.97)	$ 0.97
Diluted	$ 0.23	$ (0.15)	$ (1.97)	$ 0.97
Weighted average number of shares outstanding [(1)]	151,294	152,540	152,540	152,540

(1) For first and second quarter of 2018, amounts reflect the weighted average number of shares of common stock outstanding based on retrospectively reflecting the impacting of the Reorganization.

Total revenues for the 2018 quarters 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

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Roan Resources, Inc.

Notes to Consolidated Financial Statements

be accounted for as a deduction from revenue. The Company elected the modified retrospective method of transition. Accordingly, comparative information from the year ended December 31, 2017 has not been adjusted and continues to be reported under the previous revenue standard.

Net loss for the third quarter of 2018 includes the recognition of $299.7 million of income tax expense primarily representing the initial recording of the deferred tax liability recognized by the Company as a result of the Reorganization (see *Note 13 Income Taxes*).

	2017			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts)			
Total revenues	$ 30,979	$ 30,290	$ 39,751	$ 58,568
Income (loss) from operations	$ 16,437	$ 1,867	$ 10,974	$ (9,373)
Net income (loss)	$ 16,310	$ 1,817	$ 10,710	$ (10,380)
Earnings (loss) per share				
Basic	$ 0.22	$ 0.02	$ 0.11	$ (0.07)
Diluted	$ 0.22	$ 0.02	$ 0.11	$ (0.07)
Weighted average number of shares outstanding (1)	75,303	75,303	99,859	150,607

(1) For 2017, amounts reflect the weighted average number of shares of common stock outstanding based on retrospectively reflecting the impacting of the Reorganization.

Income (loss) from operations and net income (loss) for the 2017 quarters includes bonuses paid by Citizen of approximately $9.0 million in the second quarter, impairment of unproved properties of $4.2 million in the third quarter and amortization of unproved leasehold properties of $19.6 million in the fourth quarter. Additionally, the Linn Acquisition was completed in August 2017 and the results of the properties acquired are included in the third and fourth quarters of 2017.

Report of Independent Auditors

To the Board of Managers of Roan Resources LLC:

We have audited the accompanying financial statements of certain oil and natural gas properties contributed by Linn Energy, Inc. (the LINN Properties), which comprise the statements of revenues and direct operating expenses for the eight months ended August 31, 2017 and for the years ended December 31, 2016 and 2015.

Management s Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor s Responsibility

Our responsibility is to express an opinion on the financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Company s preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the revenues and direct operating expenses of the LINN Properties for the eight months ended August 31, 2017 and the years ended December 31, 2016 and 2015 in accordance with accounting principles generally accepted in the United States of America.

Emphasis of Matter

The accompanying special purpose financial statements reflect the revenues and direct operating expenses of the LINN Properties using the basis of preparation described in Note 1 to the financial statements and are not intended to be a complete presentation of the financial position, results of operations or cash flows of the LINN Properties. Our opinion is not modified with respect to this matter.

/s/ PricewaterhouseCoopers LLP

Houston, Texas

September 24, 2018

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STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES OF THE

PROPERTIES CONTRIBUTED BY LINN ENERGY, INC.

(Audited)

	Eight Months Ended August 31, 2017	Year Ended December 31, 2016	Year Ended December 31, 2015
		(in thousands)	
Operating revenues	$ 55,573	$ 35,274	$ 22,454
Direct operating expenses	13,888	12,434	9,448
Excess of revenues over direct operating expenses	$ 41,685	$ 22,840	$ 13,006

The accompanying notes are an integral part of the Statements of Revenues and Direct Operating Expenses.

STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES OF THE

PROPERTIES CONTRIBUTED BY LINN ENERGY, INC.

Note 1 Basis of Presentation

On August 31, 2017, Linn Energy, Inc. (LINN Energy), through certain of its subsidiaries, completed the transaction in which LINN Energy contributed certain upstream assets located in Oklahoma (the LINN Properties) to Roan Resources LLC (Roan). In exchange for their contribution, LINN Energy received a 50% equity interest in Roan.

The accompanying statements of revenues and direct operating expenses were prepared from the historical accounting records of LINN Energy. These statements are not intended to be a complete presentation of the results of operations of the LINN Properties. The statements do not include general and administrative expense, effects of derivative transactions, interest income or expense, depreciation, depletion and amortization, any provision for income tax expenses and other income and expense items not directly associated with revenues from the LINN Properties. Historical financial statements reflecting the financial position, results of operations and cash flows required by United States generally accepted accounting principles (GAAP) are not presented as such information is not readily available and not meaningful to the LINN Properties. Accordingly, the accompanying statements of revenues and direct operating expenses are presented in lieu of the financial statements required under Rule 3-05 of Securities and Exchange Commission (SEC) Regulation S-X.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions about future events that affect the reported amounts of revenues and expenses during the reporting period. These estimates and assumptions are based on management s best estimates and judgment. Management evaluates its estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic environment, which management believes to be reasonable under the circumstances. Such estimates and assumptions are adjusted when facts and circumstances dictate. As future events and their effects cannot be determined with precision, actual results could differ from these estimates. Any changes in estimates resulting from continuing changes in the economic environment will be reflected in the financial statements in future periods.

Revenue Recognition

Sales of oil, natural gas and natural gas liquids (NGL) are recognized when the product has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured, and the sales price is fixed or determinable.

Direct Operating Expenses

Direct operating expenses primarily include lease operating expenses, transportation expenses and taxes other than income taxes. Lease operating costs include expenses such as labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Taxes other than income taxes consist primarily of severance and ad valorem taxes.

Note 2 Commitments and Contingencies

Roan is not aware of any legal, environmental or other commitments or contingencies that would have a material effect on the statements of revenues and direct operating expenses.

STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES OF THE

PROPERTIES CONTRIBUTED BY LINN ENERGY, INC. - Continued

Note 3 Related Party Transactions

LINN Energy s subsidiary, Blue Mountain Midstream LLC (Blue Mountain), has an agreement in place for the processing of natural gas from certain of the LINN Properties. Transportation expenses related to such processing agreement with Blue Mountain are included in direct operating expenses on the statements of revenues and direct operating expenses.

Note 4 Subsequent Events

Following an internal reorganization, on August 7, 2018, LINN Energy completed the spin-off of Riviera Resources, Inc. (Riviera). Pursuant to the spin-off, Blue Mountain is currently a subsidiary of Riviera. The Company has evaluated subsequent events through the auditor s report date, which is the date the statements of revenues and direct operating expenses were available to be issued, and has concluded that no other events need to be reported during this period.

Note 5 Supplemental Oil and Natural Gas Reserve Information (Unaudited)

Estimated Quantities of Proved Oil and Natural Gas Reserves

Estimated quantities of proved oil, natural gas and NGL reserves at December 31, 2016, and 2015, and changes in the reserves during the years, are shown below. These reserve estimates have been prepared in accordance with SEC regulations using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month.

	Year Ended December 31, 2016			
	Natural Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total (MMcfe)
Proved developed and undeveloped reserves:				
Beginning of year	50,503	1,659	3,621	82,185
Revisions of previous estimates	2,433	(5)	540	5,641
Extensions, discoveries and other additions	76,443	5,554	10,150	170,665
Production	(6,543)	(350)	(336)	(10,657)
End of year	122,836	6,858	13,975	247,834
Proved developed reserves:				
Beginning of year	50,503	1,659	3,621	82,185
End of year	79,493	3,486	7,859	147,564
Proved undeveloped reserves:				

Beginning of year				
End of year	43,343	3,372	6,116	100,270

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STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES OF THE

PROPERTIES CONTRIBUTED BY LINN ENERGY, INC. - Continued

	Year Ended December 31, 2015			
	Natural Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total (MMcfe)
Proved developed and undeveloped reserves:				
Beginning of year	80,474	1,808	5,434	123,923
Revisions of previous estimates	(26,792)	(368)	(1,714)	(39,275)
Extensions, discoveries and other additions	1,397	391	198	4,927
Production	(4,576)	(172)	(297)	(7,390)
End of year	50,503	1,659	3,621	82,185
Proved developed reserves:				
Beginning of year	80,474	1,808	5,434	123,923
End of year	50,503	1,659	3,621	82,185
Proved undeveloped reserves:				
Beginning of year				
End of year				

The year ended December 31, 2016 includes approximately 6 Bcfe of positive revisions of previous estimates (9 Bcfe due to asset performance, partially offset by 3 Bcfe of negative revisions due to lower commodity prices). The year ended December 31, 2015 includes approximately 39 Bcfe of negative revisions of previous estimates (28 Bcfe due to lower commodity prices and 11 Bcfe due to asset performance). Reserve additions from extensions, discoveries and other additions were primarily attributable to LINN Energy s development drilling of proved acreage. During the year ended December 31, 2016, proved undeveloped reserves increased to 100 Bcfe from zero at December 31, 2015. As a result of the uncertainty regarding LINN Energy s future commitment to capital, LINN Energy reclassified all of its proved undeveloped reserves to unproved at December 31, 2015.

Standardized Measure of Discounted Future Net Cash Flows

Information with respect to the standardized measure of discounted future net cash flows relating to proved reserves is summarized below. Future cash inflows are computed by applying applicable prices relating to the LINN Properties proved reserves to the year-end quantities of those reserves. Future production, development, site restoration and abandonment costs are derived based on current costs assuming continuation of existing economic conditions. There are no future income tax expenses because Roan is not subject to federal income taxes and state taxes are not material.

	December 31, 2016	December 31, 2015
	(in thousands)	
Future estimated revenues	$ 757,928	$ 241,918
Future estimated production costs	(280,533)	(116,098)
Future estimated development costs	(116,847)	(22,633)

Future net cash flows	360,548	103,187
10% annual discount for estimated timing of cash flows	(202,790)	(49,071)
Standardized measure of discounted future net cash flows	$ 157,758	$ 54,116
Representative NYMEX prices: [1]		
Natural gas (Mcf)	$ 2.48	$ 2.59
Oil (Bbl)	$ 42.64	$ 50.16

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STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES OF THE

PROPERTIES CONTRIBUTED BY LINN ENERGY, INC. - Continued

(1) In accordance with SEC regulations, reserves were estimated using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, excluding escalations based upon future conditions. The average price used to estimate reserves is held constant over the life of the reserves.

The following summarizes the principal sources of change in the standardized measure of discounted future net cash flows:

	Year Ended December 31, 2016	Year Ended December 31, 2015
	(in thousands)	
Beginning balance	$ 54,116	$ 177,138
Sales and transfers of oil, natural gas and NGL produced during the period	(22,840)	(13,006)
Changes in estimated future development costs	572	(2,214)
Net change in sales and transfer prices and production costs related to future production	(1,788)	(109,743)
Extensions and discoveries	112,658	9,537
Net change due to revisions in quantity estimates	13,285	(23,028)
Accretion of discount	5,412	17,714
Changes in production rates and other	(3,657)	(2,282)
Ending balance	$ 157,758	$ 54,116

The data presented should not be viewed as representing the expected cash flow from, or current value of, existing proved reserves since the computations are based on a large number of estimates and arbitrary assumptions. The required projection of production and related expenditures over time requires further estimates with respect to pipeline availability, rates of demand and governmental control. Actual future prices and costs are likely to be substantially different from the current prices and costs utilized in the computation of reported amounts. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods utilized and the limitations inherent therein.

ANNEX A

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 depict 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 SEC s 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.

British thermal unit or Btu. 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.

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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).

E&P. Exploration and production.

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).

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.

Formation. A layer of rock which has distinct characteristics that differs from nearby rock.

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. 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.

MBbl. 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.

MMBoe. One million Boe.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

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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% 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. 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. 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).

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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 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.

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Section. 640 acres.

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

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.

Success rate. The percentage of wells drilled which produce hydrocarbons in commercial quantities.

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 NGLs 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.

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117,176,843 Shares

Roan Resources, Inc.

Class A Common Stock

Prospectus

, 2019

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PART II

INFORMATION NOT REQUIRED IN PROSPECTUS

Item 13. Other Expenses of Issuance and Distribution

The following table sets forth an itemized statement of the amounts of all expenses payable by us in connection with the registration of the Class A common stock offered hereby. With the exception of the SEC registration fee and the FINRA filing fee, the amounts set forth below are estimates. The selling stockholders will not bear any portion of such expenses.

SEC registration fee	$ 250,262.02
Accounting fees and expenses	*
Legal fees and expenses	*
Printing and engraving expenses	*
Miscellaneous	*
Total	$ *

* To be provided by amendment

Item 14. Indemnification of Directors and Officers

Section 145 of the DGCL provides that a corporation may indemnify any person who was or is a party, or is threatened to be made a party, to any threatened, pending or completed action, suit or proceeding, whether civil, criminal, administrative or investigative (other than an action by or in the right of the corporation by reason of the fact that he is or was a director, officer, employee or agent of the corporation, or is or was serving at the request of the corporation as a director, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise), against expenses (including attorneys fees), judgments, fines and amounts paid in settlement actually and reasonably incurred by him in connection with such action, suit or proceeding if he acted in good faith and in a manner he reasonably believed to be in or not opposed to the best interests of the corporation and, with respect to any criminal action or proceeding, had no reasonable cause to believe his conduct was unlawful. A similar standard is applicable in the case of derivative actions (i.e., actions by or in the right of the corporation), except that indemnification extends only to expenses, including attorneys fees, incurred in connection with the defense or settlement of such action and the statute requires court approval before there can be any indemnification where the person seeking indemnification has been found liable to the corporation.

Our certificate of incorporation and our bylaws will contain provisions that limit the liability of our directors and officers for monetary damages to the fullest extent permitted by the DGCL. Consequently, our directors will not be personally liable to us or our stockholders for monetary damages for breach of fiduciary duty as a director, except with respect to liability:

- for any breach of the director s duty of loyalty to our company or our stockholders;
- for any act or omission not in good faith or that involve intentional misconduct or knowing violation of law;
- under Section 174 of the DGCL regarding unlawful dividends and stock purchases; or
- for any transaction from which the director derived an improper personal benefit.

Any amendment to, or repeal of, these provisions will not eliminate or reduce the effect of these provisions in respect of any act, omission or claim that occurred or arose prior to that amendment or repeal. If the DGCL is amended to provide for further limitations on the personal liability of directors or officers of corporations, then the personal liability of our directors and officers will be further limited to the fullest extent permitted by the DGCL.

In addition, we entered into indemnification agreements with our current directors containing provisions that are in some respects broader than the specific indemnification provisions contained in the DGCL. The indemnification agreements will require us, among other things, to indemnify our directors against certain liabilities that may arise by reason of their status or service as directors and to advance their expenses incurred as a result of any proceeding against them as to which they could be indemnified. We also intend to enter into indemnification agreements with our future directors.

We intend to maintain liability insurance policies that indemnify our directors and officers against various liabilities, including certain liabilities arising under the Securities Act and the Exchange Act, that may be incurred by them in their capacity as such.

Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors, officers or persons controlling us pursuant to the foregoing provisions, we have been informed that in the opinion of the SEC, such indemnification is against public policy as expressed in the Securities Act and is therefore unenforceable.

Item 15. Recent Sales of Unregistered Securities

In connection with our incorporation on September 19, 2018, under the laws of the State of Delaware, we issued 1,000 shares of our Class A common stock to Linn Energy, Inc. for an aggregate purchase price of $1.00. These securities were offered and sold by us in reliance upon the exemption from the registration requirements provided by Section 4(a)(2) of the Securities Act. These shares were redeemed for nominal value in connection with the Reorganization.

Further, on September 24, 2018, in connection with the closing of the Reorganization and pursuant to the terms of the Master Reorganization Agreement and the Roan Holdco Merger Agreement, we issued 76,269,766 shares of our Class A common stock to Roan Holdings. This issuance of our Class A common stock did not involve any underwriters, underwriting discounts or commissions or a public offering and such issuance was exempt from registration requirements pursuant to Section 4(a)(2) of the Securities Act.

Item 16. Exhibits and Financial Statement Schedules

(a) 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 Resource, Inc. and Linn Merger Sub #3, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed on September 24, 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)

Exhibit No.	Description
5.1**	Opinion of Vinson & Elkins L.L.P.
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	Letter Agreement, dated April 13, 2019, between Roan Resources, Inc. and Joseph Mills (incorporated by reference to Exhibit 10.1 to Form 8-K filed on April 18, 2019)
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 Matthew Bonanno (incorporated by reference to Exhibit 10.14 to Form 8-K filed on September 24, 2018)
10.15	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)
10.16	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)
10.17	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)

10.18	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)

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Exhibit No.	Description
10.19	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)
10.20	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)
10.21	Indemnification Agreement, dated November 5, 2018, between Roan Resources, Inc. and Joseph A. Mills (incorporated by reference to Exhibit 10.1 to Form 8-K filed on November 6, 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	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 (incorporated by reference to Exhibit 10.25 to Form 10-K filed on April 1, 2019)
10.24	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. (incorporated by reference to Exhibit 21.1 to Form 8-K filed on September 24, 2018)
23.1*	Consent of PricewaterhouseCoopers LLP
23.2*	Consent of PricewaterhouseCoopers LLP
23.3*	Consent of DeGolyer and MacNaughton
23.4**	Consent of Vinson & Elkins L.L.P. (included in Exhibit 5.1)
24.1**	Power of Attorney (included on the signature page hereto)
99.1	Report of DeGolyer and MacNaughton, Summary of Reserves at December 31, 2018 (incorporated by reference to Exhibit 99.1 to Form 10-K filed on April 1, 2019)
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 Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

Compensatory plan or arrangement.

* Filed herewith.

** Previously filed.

(b) Financial Statement Schedules. Financial statement schedules are omitted because the required information is not applicable, not required or included in the financial statements or the notes thereto included in the prospectus that forms a part of this registration statement.

Item 17. Undertakings

Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors, officers and controlling persons of the registrant pursuant to the foregoing provisions, or otherwise, the registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against

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public policy as expressed in the Securities Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the registrant of expenses incurred or paid by a director, officer or controlling person of the registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Securities Act and will be governed by the final adjudication of such issue.

The undersigned registrant hereby undertakes that:

(1) For purposes of determining liability under the Securities Act, each prospectus filed pursuant to Rule 424(b) as part of a registration statement relating to an offering, other than registration statements relying on Rule 430B or other than prospectuses filed in reliance on Rule 430A, shall be deemed to be part of and included in the registration statement as of the date it is first used after effectiveness. *Provided, however*, that no statement made in a registration statement or prospectus that is part of the registration statement or made in a document incorporated or deemed incorporated by reference into the registration statement or prospectus that is part of the registration statement will, as to a purchaser with a time of contract of sale prior to such first use, supersede or modify any statement that was made in the registration statement or prospectus that was part of the registration statement or made in any such document immediately prior to such date of first use.

(2) For the purpose of determining any liability under the Securities Act, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

(3) To file, during any period in which offers or sales are being made, a post-effective amendment to this registration statement (i) to include any prospectus required by section 10(a)(3) of the Securities Act of 1933; (ii) to reflect in the prospectus any facts or events arising after the effective date of the registration statement (or the most recent post-effective amendment thereof) which, individually or in the aggregate, represent a fundamental change in the information set forth in the registration statement, and (iii) to include any material information with respect to the plan of distribution not previously disclosed in the registration statement or any material change to such information in the registration statement.

(4) To remove from registration by means of a post-effective amendment any of the securities being registered which remain unsold at the termination of the offering.

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SIGNATURES

Pursuant to the requirements of the Securities Act, the registrant has duly caused this registration statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Oklahoma City, State of Oklahoma, on April 18, 2019.

ROAN RESOURCES, INC.

By: /s/ Joseph A. Mills
Name: Joseph A. Mills
Title: Executive Chairman

Pursuant to the requirements of the Securities Act, this registration statement has been signed by the following persons in the capacities indicated on April 18, 2019.

Signature	Title
/s/ Joseph A. Mills Joseph A. Mills	Executive Chairman (Principal Executive Officer)
/s/ David M. Edwards David M. Edwards	Chief Financial Officer (Principal Financial Officer)
/s/ Amber N. Bonney Amber N. Bonney	Chief Accounting Officer (Principal Accounting Officer)
* Matthew Bonanno	Director
* Evan Lederman	Director
* John V. Lovoi	Director
* Paul B. Loyd, Jr.	Director

*	Director
Michael P. Raleigh	

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Signature	Title
*	Director
Andrew Taylor	
*	Director
Anthony Tripodo	

* /s/ David M. Edwards
David M. Edwards
Attorney-in-Fact

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