ROAN RESOURCES, INC.
Form 8-K
September 24, 2018

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d)

of the Securities Exchange Act of 1934

Date of report (Date of earliest event reported): September 24, 2018 (September 21, 2018)

Roan Resources, Inc.

(Exact Name of Registrant as Specified in its Charter)

Delaware	**000-51719**	**83-1984112**
(State or Other Jurisdiction of Incorporation)	**(Commission File Number)**	**(IRS Employer Identification No.)**

14701 Hertz Quail Springs Pkwy

Oklahoma City, OK	**73134**
(Address of Principal Executive Offices)	**(Zip Code)**

(405) 896-8050

Registrant s Telephone Number, including Area Code

Linn Energy, Inc.

600 Travis Street

Houston, Texas 77002

(Former Name or Former Address, If Changed Since Last Report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))
Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter). Emerging growth company

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

Introductory Note

Roan Resources History. Our predecessor, Roan Resources LLC (Roan LLC), was initially formed by Citizen Energy II, LLC (Citizen) in May 2017. In June 2017, subsidiaries of Linn Energy, Inc. (Old Linn), together with Citizen and Roan LLC entered into a contribution agreement (the 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 LINN Contributed Business and the Citizen Contributed Business, respectively, and collectively the Roan Contribution), each in exchange for a 50% equity interest in Roan LLC. On August 31, 2017 (the Contribution Date), Old Linn and Citizen consummated the transactions contemplated by the Contribution Agreement. Following these transactions, Citizen s equity interest in Roan LLC was held through its wholly owned subsidiary, Roan Holdings, LLC (Roan Holdings).

In the second 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 Inc. (subsequently renamed Linn Energy, Inc. and referred to herein as 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 Resources, Inc. (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 stockholders of New Linn (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. On August 8, 2018, Riviera began trading on the OTCQX tier of the OTC Markets Group, Inc. under the ticker symbol RVRA. Following the Riviera Separation, New Linn continued trading on the OTCQB tier of the OTC Markets Group, Inc. under the ticker symbol LNGG.

The ownership structure of Roan LLC immediately following the Riviera Separation is illustrated below:

Current Reorganization. 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 illustrated below:

To effect this further reorganization, on September 24, 2018 (the Effective Date), Roan Resources, Inc. (the Company or Roan Inc.) consummated the previously announced reorganization transaction pursuant to that certain Master Reorganization Agreement, dated as of September 17, 2018 (the Master Reorganization Agreement) by and among New Linn, Roan Holdings and Roan LLC. In connection with the Master Reorganization Agreement, the Company 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 the Company s Class A common stock, par value $0.001 per share (the 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 Holdings Holdco, LLC (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 Common Stock as merger consideration (the Holdco Merger).

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.

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. The ownership structure of the Company immediately following the Reorganization is illustrated below.

On September 25, 2018, the Company will begin trading on the OTCQB under the symbol ROAN. As of the Effective Date and following the completion of the Reorganization, Roan Holdings owned an aggregate of 76,269,766 shares of Common Stock and the Legacy Linn Stockholders collectively owned an aggregate of 76,269,766 shares of Common Stock, each representing 50% of the Company s outstanding Common Stock as of the Closing.

Following 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.

For purposes of Rule 15d-5 under the Securities Exchange Act of 1934, as amended (the Exchange Act), the Company is the successor registrant to New Linn. The Company is thereby deemed subject to the periodic reporting requirements of the Exchange Act, and the rules and regulations promulgated thereunder, and in accordance therewith will file reports and other information with the Securities and Exchange Commission (the SEC). The first periodic report required to be filed by the Company with the SEC will be its Quarterly Report on Form 10-Q for the quarter ended September 30, 2018.

Certain Defined Terms. Unless the context otherwise requires, (i) New Linn refers to the registrant prior to the Effective Date, and (ii) references herein to Roan, we, our, us, the Company and our company refer (A) prior consummation of our Reorganization, to Roan Resources LLC, a Delaware limited liability company and wholly owned subsidiary of the Company following the Reorganization and (B) after the consummation of our Reorganization, to Roan Resources, Inc. and its wholly owned subsidiaries.

Unless otherwise indicated, the historical financial, reserve and operating information presented in this Current Report on Form 8-K (the Current Report) is that of Roan LLC, our predecessor for financial reporting purposes. Further, the historical financial and operating information of Roan LLC presented in this Current Report, (i) prior to August 31, 2017, the date of the completion of the Roan 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.

Item 1.01. Entry into a Material Definitive Agreement.

Merger Agreements

The material provisions of the Merger Agreements are described under Introductory Note which is incorporated in this Item 1.01 by reference. The foregoing descriptions of the Merger Agreements set forth herein are qualified in their entirety by reference to the full text of the Merger Agreements, copies of which are attached as Exhibits 2.1 and 2.2 to this Current Report and incorporated herein by reference.

Registration Rights Agreement

On the Effective Date, in connection with the Reorganization, the Company entered into a Registration Rights Agreement (the Registration Rights Agreement) with certain significant holders of the Company s Common Stock identified on the signature pages thereto (the Holders).

Pursuant to, and subject to the limitations set forth in, the Registration Rights Agreement, the Company 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 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 the Company, subject to certain limitations set forth therein, to effect a distribution of any or all of their shares of Common Stock by means of an underwritten offering. Further, subject to certain exceptions, if at any time the Company proposes to register an offering of its equity securities or conduct an underwritten offering, whether or not for its own account, then the Company 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 the right of the Company to limit the number of shares to be included in a registration statement or underwritten offering and the Company s right to delay or withdraw a registration statement under certain circumstances. The Company will generally pay all registration expenses in connection with its 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.

The Company is 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 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 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 Common Stock up to an aggregate of 10% of the Common Stock outstanding on the Effective Date and (D) distributions of shares of Common Stock to members, partners or stockholders of such Holders.

The foregoing description of the Registration Rights Agreement is a summary only and is qualified in its entirety by reference to the Registration Rights Agreement, a copy of which is attached as Exhibit 4.1 to this Current Report and is incorporated herein by reference.

Stockholders Agreement

In connection with the Reorganization, on the Effective Date, the Company entered into a stockholders agreement (the Stockholders Agreement) with Roan Holdings and certain of the Legacy Linn Stockholders (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) the Company s 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 the Company s outstanding shares of Common Stock, each Principal Linn Stockholder shall have the right to designate one director (each, a Linn Stockholder Director) to the Company s Board of Directors (the Board) and to fill any vacancy on the Board 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 the Company s Common Stock is or will be listed and Rule 10A-3 of the Exchange Act. If a Principal Linn Stockholder s designation rights terminate as a result of no longer beneficially owning at least 5% of the Company s outstanding shares of Common Stock, the applicable Linn Stockholder Director shall be entitled to continue serving on the Board 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 Common Stock, Roan Holdings shall have the right to designate one independent director (the Roan Holdings Independent Director) to the Board (subject to the consent of the Principal Linn Stockholders) and to fill any vacancy on the Board 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 Common Stock, Roan Holdings shall have the right to designate to the Board 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 Common Stock, four directors; (ii) if Roan Holdings beneficially owns at least 15% but less than 30% of the outstanding shares of Common Stock, three directors; and (iii) if Roan Holdings beneficially owns at least 5% but less than 15% of the outstanding shares of Common Stock, two directors, and, in each case, to fill any vacancy on the Board 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 the Company s outstanding shares of Common Stock, the Roan Holdings Directors shall be entitled to continue serving on the Board until the end of such Roan Holdings Directors terms.

Additionally, pursuant to the Stockholders Agreement the Company has 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 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, 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.

The foregoing description of the Stockholders Agreement is a summary only and is qualified in its entirety by reference to the Stockholders Agreement, a copy of which is attached as Exhibit 4.2 to this Current Report and is incorporated herein by reference.

Credit Facility

On September 5, 2017, Roan LLC entered into a credit agreement with Citibank, N.A., as administrative agent, and a syndicate of lenders, that provided for the credit facility in the aggregate principal amount of up to $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 amended to date, the credit facility). On April 9, 2018, the borrowing base under the credit facility was set at $425.0 million. The credit facility matures on September 5, 2022.

Roan LLC may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs. The obligations of Roan LLC under the credit facility are guaranteed by each direct or indirect wholly-owned U.S. restricted subsidiary of Roan LLC that is not explicitly an excluded subsidiary (such entities, the Guarantors). The obligations of Roan LLC and the Guarantors are secured by substantially all assets of

Roan LLC and the Guarantors.

Borrowings under the credit facility bear interest at a rate equal to, at Roan LLC s option, either (1) a base rate plus an applicable margin ranging between 1.25% per annum and 2.25% per annum, based upon the amount of availability under the borrowing base or (2) a LIBOR rate plus an applicable margin ranging between 2.25% per annum and 3.25% per annum, based upon the amount of availability under the borrowing base.

The credit facility contains customary representations and warranties and customary affirmative and negative covenants that 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.

The credit facility also requires Roan LLC 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 Financial Accounting Standards Board s (FASB) Accounting Standard Codification (ASC) 815 or 410) to our consolidated current liabilities (excluding the current portion of long-term debt under our credit facility, non-cash liabilities under ASC 815 or 410) and reclamation obligations classified as current liabilities under United States generally accepted accounting principles (GAAP), of not less than 1.0 to 1.0.

The foregoing description of the credit facility is a summary only and is qualified in its entirety by reference to the credit facility, a copy of which is attached as Exhibit 10.1 to this Current Report and is incorporated herein by reference.

Amended and Restated Management Incentive Plan

The material provisions of the Company s Amended and Restated Management Incentive Plan (the Amended and Restated Plan) are described under Item 5.02 which is incorporated in this Item 1.01 by reference.

Voting Agreement

Following the Linn Merger and the Holdco Merger, on the Effective Date, the Company entered into a voting agreement (the Voting Agreement) with the principal stockholders. Pursuant to the terms of the Voting Agreement, the principal stockholders agreed, among other things, to vote, at least one business day following the Effective Date but no later than three business days following the Effective Date, all of their outstanding shares of the Company s Common Stock currently held or thereafter acquired by the principal stockholders (the Principal Shares) (i) in favor of the adoption and approval of the form of second amended and restated certificate of incorporation of the Company, the form of second amended and restated bylaws of the Company, the form of amended and restated certificate of incorporation of New Linn and the form of second amended and restated bylaws of New Linn, and (ii) against any proposal made in opposition to, or in competition with, such amendment and restatement of the existing amended and restated certificate of incorporation and amended and restated bylaws of the Company and the existing certificate of incorporation and existing amended and restated bylaws of New Linn (the Original Charter Documents), and against any other proposal, action or transaction involving the Company, New Linn or any of the Company s other subsidiaries, which proposal, action or transaction would reasonably be expected to impede, frustrate, prevent or materially delay the amendment and restatement of the Original Charter Documents or other transactions contemplated by the Voting Agreement. The Company agreed to take all necessary action to effectuate the foregoing.

The foregoing description of the Voting Agreement is a summary only and is qualified in its entirety by reference to the Voting Agreement, a copy of which is attached as Exhibit 10.6 to this Current Report and is incorporated herein by reference.

Second Amended and Restated Limited Liability Company of Roan LLC

On the Effective Date, 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.

The foregoing description of the Roan LLC Agreement is a summary only and is qualified in its entirety by reference to the Roan LLC Agreement, a copy of which is attached as Exhibit 10.7 to this Current Report and is incorporated herein by reference.

Indemnification Agreements

The Company has entered into indemnification agreements with each of our directors. These agreements 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. The foregoing description of the indemnification agreements is a summary only and is qualified in its entirety by reference to the indemnification agreements, which are attached as Exhibits 10.13 to 10.20 to this Current Report and are incorporated herein by reference.

Item 1.02 Termination of a Material Agreement.

Old Linn Registration Rights Agreement

The parties to that certain registration rights agreement (the Prior RRA), dated as of February 28, 2017, among Old Linn, and the other parties thereto, agreed to terminate the Prior RRA and their rights and obligations thereunder immediately prior to the Reorganization.

Item 2.01 Completion of Acquisition or Disposition of Assets.

The disclosure set forth under Introductory Note above is incorporated in this Item 2.01 by reference.

On the Effective Date, pursuant to the terms of the Merger Agreements, separate wholly owned subsidiaries of the Company merged with and into Roan Holdco and New Linn, respectively, with each of Roan Holdco and New Linn surviving the relevant merger as wholly owned subsidiaries of the Company, and the limited liability company agreement of Roan LLC (the Roan LLC Agreement) was amended and restated to cause Roan LLC to be a manager-managed limited liability company. As consideration for the Reorganization, the Company issued (i) an aggregate of 76,269,766 shares of Common Stock to the Legacy Linn Stockholders and (ii) an aggregate of

76,269,766 shares of Common Stock to Roan Holdings, the sole member of Roan Holdco.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

The information in this Current Report, including the exhibits hereto, includes forward-looking statements. All statements, other than statements of historical fact included in this Current Report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Current Report, the words could, believe, anticipate, intend, estimate, expect, project and similar expressions are intended to identify forward-looking statements, althou 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 below under the heading Risk Factors.

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 natural gas liquid (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 Current Report that are not historical.

These forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, 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 below.

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 Current Report 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 Current Report 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, the Company disclaims 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 hereof.

WHERE YOU CAN FIND MORE INFORMATION

Statements contained in this Current Report 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 Current Report, reference is made to the exhibits for a more complete description of the matter involved. A copy of the Current Report, and the exhibits and schedules thereto, may be inspected without charge at the public reference facilities maintained by the SEC at 100 F Street NE, Washington, D.C. 20549. Copies of these materials may be obtained, upon payment of a duplicating fee, from the Public Reference Room of the SEC at 100 F Street N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the operation of the Public Reference Room. The SEC maintains a website that contains reports, proxy and information statements and other information regarding registrants that file electronically with the SEC. The address of the SEC s website is *www.sec.gov*.

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.

Business and Properties

Roan Inc. was incorporated to serve as a holding company and, prior to the Reorganization, had no previous operations, assets or liabilities. The historical operating information included in this Current Report is the information of Roan LLC, our accounting predecessor, and the historical operating information of Roan LLC presented in this Current Report, (i) prior to August 31, 2017, the date of the completion of the Contribution is that of Citizen, the predecessor of Roan LLC for financial reporting purposes and (ii) on and after August 31, 2017, is that of

Roan LLC. Therefore, the operating information of Citizen prior to August 31, 2017 does not include financial information relating to the Linn Contributed Business.

Our Company

We are an independent oil and natural gas company with a primary focus on the development of our assets throughout the Merge, SCOOP and STACK plays of the 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 producing oil and natural gas basins in the United States.

Our assets consist of over 150,000 net acres in the Merge, SCOOP and STACK plays within the Anadarko Basin. We focus our development on formations where we believe we can apply our technical and operational expertise in order to increase proved reserves and production to deliver compelling economic rates of return on a risk adjusted basis.

Our primary developmental focus is on our Merge acreage position in Canadian, Grady and McClain counties in Central Oklahoma, where we have over 115,000 net acres. Our acreage position is concentrated in the oil and liquids-rich fairways of the Merge play, and provides us development opportunities through multiple stacked development horizons. We believe these development horizons have been substantially de-risked through industry development of approximately 300 horizontal wells. Our acreage position throughout the Merge is largely held by production, has a high average working interest and is predominantly contiguous, providing us with a high degree of operational control and development flexibility.

The vast majority of our acreage in the SCOOP play is prospective for the Woodford and Springer shales, which are generally characterized by long-lived reserves and have had high drilling success rates. Our acreage in the STACK play has been delineated by numerous industry wells, which have been demonstrated to be economically productive through various formations.

As of June 30, 2018, we had six rigs operating across our acreage position and we added two additional rigs in the third quarter of 2018. Our rigs are focused on drilling long lateral horizontal wells primarily in the Merge play. As of June 30, 2018, we operated 556 gross wells and had an interest in an additional 590 gross wells throughout our area of operations.

Our Properties

The map below depicts the location of our properties as of June 30, 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 Current Report. As of June 30, 2018, we operated approximately 76% of our net acreage and had an average working interest of approximately 74% in all of our operated acreage. From January 1, 2018 through June 30, 2018, we drilled or participated in 91 gross horizontal wells on production.

As of June 30, 2018, approximately 80% 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 six months ended June 30, 2018, our average net daily production was 36.9 MBoe/d (approximately 29% oil, 45% natural gas and 26% NGLs). During 2017, our average net daily production was 16.2 MBoe/d (approximately 25% oil, 49% natural gas and 26% NGLs). As of June 30, 2018, we had 1,146 gross (463 net) producing wells online, operated and non-operated.

Oil and Natural Gas Data

Proved Reserves

Evaluation of Proved Reserves. Our proved reserve estimates as of December 31, 2017 were prepared by DeGolyer and MacNaughton, our independent reserve engineers. 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 33 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, 2017 is included as Exhibit 99.5 to this Current Report.

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. Keith Case is our Corporate Reserves Advisor and primarily responsible for overseeing the preparation of the reserves estimates by DeGolyer and MacNaughton. Mr. Case 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, Andrew Chodur, assists Mr. Case in the reserves preparation process. He has 13 years of industry experience in reserve estimation and petroleum economics. Mr. Chodur 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.

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 Mr. Chodur 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 proved undeveloped reserves (PUDs) additions;
- review by our management team of reported proved reserves and significant reserve changes;
- direct reporting responsibilities by our Manager Reservoir Engineering 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, 2017 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 our estimated net proved reserves as of December 31, 2017, prepared in accordance with the rules and regulations of the SEC. All of our proved reserves are located in the United States.

		December 31, 2017(1)
Proved developed reserves:		
Oil (MBbls)		12,352
Natural gas (MMcf)		259,193
NGLs (MBbls)		24,034
Total (MBoe)(2)		79,585
Proved undeveloped reserves:		
Oil (MBbls)		25,068
Natural gas (MMcf)		426,676
NGLs (MBbls)		55,544
Total (MBoe)(2)		151,724
Total proved reserves:		
Oil (MBbls)		37,420
Natural gas (MMcf)		685,869
NGLs (MBbls)		79,578
Total (MBoe)(2)		231,309
Benchmark Oil and Natural Gas Prices(1):		
Oil WTI per Bbl	$	51.34
Natural gas Henry Hub per MMBtu	$	2.98
Standardized measure (in thousands)(3)	$	1,195,669
Pro forma standardized measure (in thousands)(4)	$	956,847
SEC Pricing PV-10 (in thousands)(5)	$	1,195,669

(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 $51.34 per barrel as of December 31, 2017, 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 $2.98 per MMBtu as of December 31, 2017, 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 $49.43 per barrel of oil, $19.00 per barrel of NGLs and $2.78 per Mcf of natural gas as of December 31, 2017.

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

(3) As of December 31, 2017, we were a limited liability company and as a result, we were not subject to entity-level U.S. federal, state and local income taxes. Following our Reorganization, we are subject to U.S. federal, state and local income taxes. Accordingly, estimates included herein of future net cash flows may be materially different from the future net cash flows that are ultimately received. Future calculations of standardized measure will include the effects of income taxes on future net cash flow. Please see Risk Factors The standardized measure of our estimated reserves contained in the footnotes to our financial statements is not an accurate estimate of the current fair value of our estimated reserves.

(4) Following our Reorganization, we became subject to U.S. federal, state and local income taxes and our future income taxes are dependent on our future taxable income. As of December 31, 2017, we estimate that our pro forma standardized measure would have been approximately $956.9 million, as adjusted to give effect to the present value of approximately $238.8 million of future income taxes as a result of our being treated as a corporation for federal income tax purposes. We have assumed pro forma tax expense using a 25.7% blended corporate level federal and state tax rate.

(5) 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. Because Roan LLC was not subject to entity level U.S. federal, state and local income taxes, prior to the Reorganization, as of December 31, 2017, the PV-10 value and standardized measure of our properties were equal. Following our Reorganization, we were subject to U.S. federal, state and local income taxes. Accordingly, estimates included herein of future net cash flows may be materially different from the future net cash flows that are ultimately received. Future calculations of standardized measure will include the effects of income taxes on future net cash flow. Please see Risk Factors The standardized measure of our estimated reserves contained 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.

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 Current Report.

Additional information regarding our proved reserves can be found in the notes to our financial statements included in Exhibit 99.1 to this Current Report and in the reserve report of DeGolyer and MacNaughton as of December 31, 2017, which is included as Exhibit 99.5 to this Current Report.

PUDs

As of December 31, 2017, our PUDs totaled 25,068 MBbls of oil, 426,676 MMcf of natural gas and 55,544 MBbls of NGLs, for a total of 151,724 MBoe. PUDs will be converted from undeveloped to developed as the applicable wells are drilled and begin production.

Prior to August 31, 2017, PUDs were not booked. As a result of the Contribution to Roan LLC and its development plan and capital availability, PUDs were booked during the remainder of 2017. The following table summarizes our changes in PUDs during the year ended December 31, 2017(in MBoe):

Balance, December 31, 2016	
Purchase of reserves in place	27,920
Revisions of previous estimates	(13,245)
New discoveries and extensions	150,100
Transfers to proved developed	(13,051)
Balance, December 31, 2017	151,724

We purchased 27,920 MBoe during the year ended December 31, 2017. New discoveries and extensions of 150,100 MBoe during the year ended December 31, 2017 resulted primarily from new proved undeveloped locations added as a result of our drilling activity. Downward revisions of previous estimates of 13,245 MBoe during the year ended December 31, 2017 were primarily due to the movement of PUD locations within units and adjustments to the mix of oil and natural gas based on the evaluation of offset well activity in 2017. Additionally, during the period ended December 31, 2017, we spent $148.5 million to convert 13,051 MBoe to proved developed producing reserves.

Our estimated future development costs relating to the development of PUDs at December 31, 2017 were projected to be approximately $715.8 million over the next five years, which we expect to finance through cash flow from operations, borrowings under our revolving 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, 2017, approximately 7,500 MBoe of our total proved reserves relating to six drilled but uncompleted wells (DUCs) were classified as PDNP. In January 2018, all six DUCs were completed and reported production. Completion costs associated with these six DUCs were approximately $29.0 million.

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:

	Six Months Ended June 30,		**Year Ended December 31,**		
	2018	**2017**	**2017**	**2016**	**2015**
Production data:					
Oil (MBbls)	1,915	536	1,454	733	97
Natural gas (MMcf)	18,069	5,814	17,582	6,252	430
NGLs (MBbls)	1,757	506	1,524	544	48
Total (MBoe)(1)	6,684	2,011	5,908	2,319	216
Average daily production (MBoe/d)	36.9	11.1	16.2	6.4	0.6

Average prices(2):					
Oil (per Bbl)	$ 63.90	$ 54.06	$ 52.87	$ 41.72	$ 40.97
Natural gas (per Mcf)	$ 1.71	$ 3.10	$ 2.80	$ 2.57	$ 2.45
NGLs (per Bbl)	$ 21.78	$ 23.67	$ 26.44	$ 15.26	$ 13.71
Total (per Boe)	$ 28.66	$ 29.34	$ 28.16	$ 23.70	$ 26.32
Average realized prices after effects of derivative settlements(2)(3):					
Oil (per Bbl)	$ 55.70	$ 54.06	$ 53.57	$ 41.72	$ 40.97
Natural gas (per Mcf)	$ 1.81	$ 3.12	$ 2.89	$ 2.57	$ 2.45
NGLs (per Bbl)	$ 21.78	$ 23.67	$ 26.44	$ 15.26	$ 13.71
Total (per Boe)	$ 26.58	$ 29.41	$ 28.60	$ 23.70	$ 26.32

	Six Months Ended June 30, 2018	2017	Year Ended December 31, 2017	2016	2015
Average costs (per MBoe)(2):					
Production expenses	$ 2.30	$ 3.04	$ 2.86	$ 2.19	$ 2.54
Gathering, transportation and processing expenses		3.22	3.15	2.55	1.26
Production taxes	0.70	0.60	0.62	0.47	0.88
Exploration expenses	2.77	0.12	5.52	2.27	0.56
Depreciation, depletion, amortization and accretion	6.95	5.64	6.33	10.78	9.68
General and administrative	4.06	8.74	5.31	2.41	9.60
Gain on sale of oil and natural gas properties			(0.14)		
Total	$ 16.78	$ 21.36	$ 23.65	$ 20.67	$ 24.52

(1) May not sum or recalculate due to rounding.

(2) Average prices and costs for the six months ended June 30, 2018 reflect the adoption of Accounting Standards Codification Topic 606, *Revenue from Contracts with Customers* (ASC 606) on January 1, 2018. The adoption of ASC 606 requires certain costs that were previously recorded as gathering, processing and transportation expenses to be accounted for as a deduction from revenue. We elected the modified retrospective method of transition. Accordingly, comparative information has not been adjusted and continues to be reported under the previous revenue standard.

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

Productive Wells

The following table sets forth information as of June 30, 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	119	92	437	320	556	412
Non-operated	266	16	324	36	590	52
Total	385	108	761	356	1,146	464

Developed and Undeveloped Acreage

The following table sets forth information as of June 30, 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)**
251,202	163,965	62,173	37,898	313,375	201,863

(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 June 30, 2018, approximately 80% of our total net acreage was held by production. The following table sets forth the gross and net undeveloped acreage, as of June 30, 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.

Remaining 2018		2019		2020		2021		2022 and Thereafter	
Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
8,873	5,616	15,948	10,434	25,515	13,346	11,815	8,487	22	15

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. Through our drilling activity or drilling activity of third parties, we expect to develop approximately 3,200 of the net undeveloped acres set to expire in 2018. Of the 10,434 net acres expiring in 2019 and the 13,346 net acres expiring in 2020, we have the right to extend on 1,344 and 1,779 net acres, respectively, at a cost of approximately $6.7 million and $7.7 million, respectively.

Drilling Results

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

	For the Six Months Ended June 30,				For the Year Ended December 31,					
	2018		2017		2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:										
Productive(1)										
Dry										
Total Exploratory										
Development Wells:										
Productive(1)	91	30	25	8	93	35	55	19	38	3
Dry										
Total Development	91	30	25	8	93	35	74	19	56	3
Total Wells:										
Productive(1)	91	30	25	8	93	35	55	19	38	3
Dry										

Total	91	30	25	8	93	35	55	19	38	3

(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 June 30, 2018, we had six gross (four net) wells in the process of being drilled and 21 gross (16 net) wells waiting on completion with associated remaining net completion costs of approximately $58.0 million. All of these wells are located in the Merge play.

Operations

General

As of June 30, 2018, we operated approximately 76% 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.

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 six months ended June 30, 2018 and 2017 and the years ended December 31, 2017, 2016 and 2015:

	Six Months Ended, June 30,		Year Ended December 31,		
	2018	**2017**	**2017**	**2016**	**2015**
Sunoco Inc.	26%	42%	40%	55%	61%
EnLink Oklahoma Gas Processing, LP	20%	40%	39%	31%	*
Coffeyville Resources Refining & Marketing, LLC	19%	*	*	*	*
Blue Mountain Midstream, LLC	12%	*	*	*	*
Cimarex Energy Company	*	*	*	*	14%

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

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.

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 Current Report.

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 80% of our working interest, with an average net revenue interest of 77%.

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Historically, our compliance costs have not had a material adverse effect on our results of operations; however, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission (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 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 the company, as well as the revenues received for sales of such production. Gathering systems may be subject to state ratable take and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase, or accept for gathering, without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes may affect whether and to what extent gathering capacity is available for natural gas production, if any, of the drilling program and the cost of such capacity. Further state laws and regulations govern rates and terms of access to intrastate pipeline systems, which may similarly affect market access and cost.

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

In addition to the regulation of natural gas pipeline transportation, FERC has jurisdiction over the purchase or sale of natural gas or the purchase or sale of transportation services subject to FERC s jurisdiction pursuant to the Energy Policy Act of 2005 (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 Natural Gas Act of 1938 (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 the company.

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

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

In addition to FERC s regulations, we are required to observe anti market manipulation laws with regard to our physical sales of energy commodities. In November 2009, the Federal Trade Commission (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 Commodity Futures Trading Commission (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. 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. Were the EPA to propose 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) but several legal challenges to this rule followed, and the WOTUS rules was stayed nationwide in October 2015 pending resolution of the court challenges. The EPA and the Corps proposed a rulemaking in June 2017 to repeal the WOTUS rule, and announced their intent to issue a new rule defining the CWA s jurisdiction. In January 2018, the U.S. Supreme Court issued a decision finding that jurisdiction to hear challenges to the WOTUS rule resides with the federal district courts; consequently, the previously filed district court cases have been allowed to proceed. Following the Supreme Court s decision, the EPA and the Corps issued a final rule in January 2018 staying implementation of the WOTUS rule for two years while the agencies reconsider the rule. Multiple states and environmental groups have challenged the stay, and future implementation of the WOTUS rule is uncertain at this time. To the extent this rule or a revised rule expands the scope of the CWA s jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas in connection with any expansion activities. Federal and state regulatory agencies 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 Oklahoma Corporation Commission (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 2017 the OCC issued an order limiting future increases in the volume of oil and natural gas wastewater injected below ground into the Arbuckle formation in an effort to reduce the number of earthquakes in the state, and imposed further reductions in the Edmonds area of the state in August 2017. In addition, these seismic events have also led to an increase in tort lawsuits filed against exploration and production companies as well as the owners of underground injection wells.

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

Air Emissions

The federal Clean Air Act (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 National Ambient Air Quality Standard (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. 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. The EPA had previously proposed an extension delaying implementation of the new ozone NAAQS, but subsequently withdrew the extension in late August 2017. The EPA was required to formally designate areas as either being in attainment or non-attainment with the new ozone standards by October 1, 2017, but missed the deadline. Subsequently, in November 2017, the EPA published a list of areas that are in compliance with the new ozone standards and separately in December 2017 issued responses to state recommendations for designating non-attainment areas. States have the opportunity to submit new air quality monitoring to EPA prior to EPA finalizing any non-attainment designations. While the EPA has preliminarily determined that all counties in which we operate are in attainment with the new ozone standards, these determinations may be revised in the future. Reclassification of areas or imposition of more stringent standards may make it more difficult to construct new facilities or modify existing facilities in these newly designated non-attainment areas. In another example, in June 2016, the EPA finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of oil and natural gas projects and increase our costs of development and production, which costs could be significant.

Climate Change

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

There has not been significant activity in the form of federal legislation to reduce GHG emissions in recent years. In the absence of such federal climate legislation, a number of state and regional cap and trade programs have emerged that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. The EPA has also developed strategies for the reduction of methane emissions, including emissions from the oil and 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. These Subpart OOOOa standards expand previously issued NSPS published by the EPA in 2012, known as Subpart OOOO, by using certain equipment-specific emissions control practices. Affected methane and VOC sources include hydraulically fractured (or re-fractured) oil and natural gas well completions, fugitive emissions from well sites and compressors, and pneumatic pumps. However, the Subpart OOOOa standards have been subject to attempts by the EPA to stay portions of those standards, and the agency proposed a rulemaking in June 2017 to stay the requirements for a period of two years and revisit implementation of Subpart OOOOa in its entirety. The EPA has not yet published a final rule, and, as a result of these developments, EPA s 2016 standards remain in effect but future implementation of the 2016 standards is uncertain at this time. Various industry and environmental groups have separately challenged both the methane requirements and EPA s attempts to delay implementation of the rules, and, in April 2018, several states filed a lawsuit that seeks to compel EPA to issue methane performance standards for existing sources in the oil and natural gas source category. In addition, the U.S. Department of the Interior 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. The rule seeks to minimize venting and flaring of emissions from storage tanks and other equipment, and also to impose leak detection and repair requirements. In December 2017, the BLM issued a final rule temporarily suspending implementation of its methane rule until January 2019; however, in February 2018, a federal district court issued a preliminary injunction prohibiting BLM from enforcing the stay. As a result, the November 2016 rule, as originally promulgated, is in effect. Separately, also in February 2018, the BLM proposed a rule to rescind the agency s 2016 methane rule. Additional litigation related to the proposed rescission is likely. 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). 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. Moreover, activists concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and gas will continue to represent a substantial percentage of global energy use over that time. 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, the EPA published final CAA regulations in 2012 and, more recently, in June 2016 governing performance standards, including standards for the capture of air emissions released during oil and natural gas hydraulic fracturing, leak detection, and permitting and separately published in June 2016 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.

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, noting that the following hydraulic fracturing water cycle activities and local-or regional-scale factors are more likely that others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. 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 federal Endangered Species Act (ESA), and comparable state laws were established to protect endangered and threatened species and their habitat. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act (MBTA). We may conduct operations on oil and natural gas leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species that potentially could be listed as threatened or endangered under the ESA may exist. Moreover, as a result of a 2011 settlement agreement, the U.S. Fish and Wildlife Service (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.

Employees

As of September 17, 2018, we had 158 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.

Corporate Headquarters

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

Business Purpose of Reorganization

As a result of the Reorganization, the ownership interests of Roan LLC were aligned under a single corporate holding company with a single class of ownership interests, rather than being separately owned by Roan Holdings and New Linn. The Reorganization, in which there is a single public company, will eliminate the risk of having both New Linn and Roan LLC being publicly traded companies. Moreover, the Reorganization will allow Roan Holdings and New Linn to transition into a pure-play oil and natural gas company, with matters relating to the Company s operations, personnel, policies and practices decided within a single corporate governance framework. In addition, we expect that the Reorganization will reduce administrative and compliance complexities caused by the separate ownership of Roan LLC by Roan Holdings and New Linn. Finally, as a result of the foregoing, it is anticipated that the Reorganization will provide greater access to equity funding through future stock issuances and enable the company to utilize more standard equity-based employee incentive plans.

Risk Factors

Investing in our Common Stock involves risks. You should carefully consider the information in this Current Report, including the matters addressed under Cautionary Note 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 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. 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. Oil and natural gas prices began to recover and reached levels as high as $74.15 per Bbl and $3.20 per MMBtu, respectively, during the first half of 2018. 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 the first half 2018, reaching levels as high as $8.57 per MMBtu. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control that include, but are not limited to, the following:

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

- the price and availability of alternative fuels; and

- U.S. federal, state and local and non-U.S. governmental regulation and taxes.

Lower commodity prices may reduce our cash flows and borrowing ability. If we are unable to obtain needed capital or financing on satisfactory terms, our ability to develop our reserves could be adversely affected. Furthermore, using lower prices in estimating proved reserves may result in a reduction in proved reserve volumes due to economic limits. In addition, sustained periods with oil and natural gas prices at levels lower 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 2018 capital expenditures with cash generated by operations and borrowings under our credit facility; however, our financing needs may require us to alter or increase our capitalization substantially through the incurrence of additional indebtedness or the issuance of debt or equity securities or the sale of assets. The incurrence of additional indebtedness would require that a portion of our cash flow from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flow from operations to fund working capital, capital expenditures and acquisitions. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, oil, natural gas and NGL prices; actual drilling results; the availability of drilling rigs and other services and equipment; and regulatory, technological and competitive developments. A reduction in commodity prices from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to grow production.

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

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

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

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

Our assets were contributed to Roan LLC in August 2017 by 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 operating information available upon which to base investors 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.

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 semi-annually 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 Current Report and in the footnotes to our financial statements is not an accurate estimate of the current fair value of our estimated reserves.

Standardized measure is a reporting convention that provides a common basis for comparing oil and natural gas companies subject to the rules and regulations of the SEC. Standardized measure requires the use of specific pricing as required by the SEC, as well as operating and development costs prevailing as of the date of computation. Consequently, it may not reflect the prices ordinarily received or that will be received for oil and natural gas production because of varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the oil and natural gas properties. In addition, our accounting predecessor, Roan LLC, passed through its taxable income to its owners for income tax purposes and was not subject to U.S. federal, state or local income taxes. Accordingly, our standardized measure does not provide for U.S. federal, state or local income taxes. However, following our Reorganization, we are subject to U.S. federal, state and local income taxes. 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 Current Report should not be construed as accurate estimates of the current fair value of our proved reserves.

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

As of December 31, 2017, approximately 65.6% 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 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, 2017 or for the six months ended June 30, 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 over-the-counter (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 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 and the ability or willingness of counterparties to trade opposite us, potentially increasing costs for transactions. Moreover, such changes could materially reduce our hedging opportunities which could adversely affect our revenues and cash flow during periods of low commodity prices. While many Dodd-Frank Act regulations are already in effect, the rulemaking and implementation process is ongoing, and the ultimate effect of the adopted rules and regulations and any future rules and regulations on our business remains uncertain.

In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions or counterparties with other businesses that subject them to regulation in foreign jurisdictions, we may become subject to or otherwise impacted by such regulations. At this time, the impact of such regulations is not clear.

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

Subject to our management determining an appropriate number of wells to drill per section from a spacing perspective, we expect to identify a large number of future drilling locations on our existing acreage. These drilling locations will represent a significant part of our growth strategy. Our ability to drill and develop these locations will depend on a number of uncertainties, including oil, natural gas and NGL prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, access to suitable surface drilling pad locations, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the drilling locations our management team identifies will ever be drilled or if we will be able to produce oil, natural gas or NGLs from these or any other drilling locations.

In addition, we may require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital or financing required to do so. Please see Our business requires substantial capital expenditures. We may be unable to generate sufficient cash from operations or obtain required capital or financing as needed or on acceptable terms, which could lead to a decline in our ability to access or grow production and reserves.

Approximately 19% 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, 2017, approximately 19% 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 June 30, 2018, we had over 150,000 net acres in the Merge, STACK and SCOOP plays of the Anadarko Basin, approximately 76% of which we operated. As of June 30, 2018, we were the operator on 556 (412 net) of our 1,146 gross (464 net) producing wells. We will have limited ability to exercise influence over the operations of the drilling locations operated by our partners and there is the risk that our partners may at any time have economic, business or legal interests or goals that are inconsistent with ours. Furthermore, the success and timing of development activities operated by our partners will depend on a number of factors that will be largely outside of our control that include, but are not limited to, the following:

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

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

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

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

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

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Drought conditions have persisted in Oklahoma in past years. Although we have not been directly affected to date, these drought conditions have led governmental authorities in other areas of the state to restrict the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supplies. If we are unable to obtain water to use in our operations, or if we experience delays in obtaining water sourcing permits or other rights, we may be unable to economically produce oil, natural gas and NGLs, which could have a material and adverse effect on our financial condition, results of operations and cash flows.

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

All of our producing properties are geographically concentrated in the Merge, STACK and SCOOP plays within the Anadarko Basin in Central Oklahoma. At December 31, 2017, 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 of our production is dependent upon transportation and other facilities, certain of which we do not control. If these facilities are unavailable, 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. As a result, 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. We have multiple dedications within certain of our operated sections. As a result, we are required to manage our production to ensure these commitments are satisfied. If we are unable to effectively manage these split dedications within a section with multiple dedications, we would be in breach of one of the midstream contracts, which could have an adverse effect on our business and financial condition.

We may enter into firm transportation, gas processing, gathering and compression service, water handling and treatment, or other agreements that require minimum volume delivery commitments. We are currently party to a firm transportation agreement, which contains a minimum volume delivery commitment of natural gas from a specific area. Although we expect to meet the minimum volume delivery commitment under this contract, in the event that we are unable to fully satisfy this natural gas volume delivery commitment, we would incur deficiency fees. Lower commodity prices may lead to reductions in our drilling program, which may result in insufficient production to utilize our full firm transportation and processing capacity. If we have insufficient production to meet the minimum volumes under this agreement or any other firm commitment agreement we may enter into, our cash flow from operations will be reduced, which may require us to reduce or delay our planned investments and capital expenditures or seek alternative means of financing, all of which may have a material adverse effect on our results of operation.

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

Our top two customers represented approximately 79% and 46% of our total revenue for the year ended December 31, 2017 and the six months ended June 30, 2018, respectively. 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 any such greater than 10% purchaser as a purchaser could adversely affect our revenues in the short term.

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

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

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

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

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

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

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

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;

- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

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

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

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

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

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

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

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

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

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

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

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

Our operations are subject to numerous stringent and complex federal, state and local laws and regulations governing, among other things, occupational safety and health aspects of our operations, the discharge of materials into the environment (such as the venting or flaring of natural gas and the emission of GHGs and other air pollutants), the generation, management and disposal of solid or hazardous wastes and the protection of the environment and natural resources (including threatened and endangered species). These laws and regulations may impose numerous obligations applicable to our operations, including the acquisition of a permit or other approval before conducting drilling and other regulated activities; the restriction of types, quantities and concentration of materials that may be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations, and reclamation and restoration costs. Numerous governmental authorities, such as the 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

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may result in the assessment of sanctions, including administrative, civil or criminal penalties, natural resource damages, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations or specific projects and limit our growth and revenue.

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

The trend in environmental regulation has been towards more stringent requirements, and any changes that result in more stringent or costly well drilling, construction, completion or water management activities, air emissions control or waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our results of operations, competitive position or financial condition. For example, in October 2015, the EPA issued a final rule under the CAA, lowering the NAAQs for ground level ozone from the current standard of 75 parts per billion (ppb) for the current 8 hour primary and secondary ozone standards to 70 ppb for both standards. 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. The EPA was required to formally designate areas as either being in attainment or non-attainment with the new ozone standards by October 1, 2017, but missed the deadline. Subsequently, in November 2017, the EPA published a list of areas that are in compliance with the new ozone standards and separately in December 2017 issued responses to state recommendations for designating non-attainment areas. States have the opportunity to submit new air quality monitoring to the EPA prior to the EPA finalizing any non-attainment designations. While the EPA has preliminarily 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. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our activities that could have a material and adverse impact on our ability to develop and produce our reserves.

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

Under the EPAct 2005, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to approximately $1.2 million per day for each violation. The FERC may also impose administrative and criminal remedies and disgorgement of profits associated with any violation. While our operations have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting requirements. We also must comply with the anti-market manipulation rules enforced by FERC. Additional rules and regulations pertaining to those and other matters may be considered or adopted by FERC from time to time. Additionally, the FTC has regulations intended to prohibit market manipulation in the petroleum industry with authority to fine violators of the regulations civil penalties of up to approximately $1.2 million per day, and the CFTC prohibits market manipulation in the markets regulated by the CFTC, including similar anti manipulation authority with respect to swaps and futures contracts as that granted to the CFTC with respect to oil purchases and sales. The CFTC rules subject violators to a civil penalty of up to the greater of approximately $1.1 million or triple the monetary gain to the person for each violation. Failure to comply with those regulations in the future could subject us to civil penalty liability, as described in Business Regulation of the Oil and Natural Gas Industry.

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

In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the CAA that, among other things, establish PSD construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that are already potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet best available control technology standards that typically will be established by state agencies. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from specified large GHG emission sources in the United States, including certain onshore oil and natural gas production sources, which include certain of our operations. Recent federal regulatory action with respect to GHG emissions from the oil and natural gas sector has focused on methane emissions. For example, in June 2016, the EPA published performance standards 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. However, over the past year the EPA has taken several steps to delay implementation of its methane standards, and the agency proposed a rulemaking in June 2017 to stay the requirements for a period of two years and revisit implementation of the methane rule in its entirety. The EPA has not yet published a final rule, and, as a result of these developments, EPA s 2016 standards remain in effect but future implementation of the 2016 standards is uncertain at this time. Various industry and environmental groups have separately challenged both the methane requirements and EPA s attempts to delay implementation of the rules. In addition, in April 2018, several states filed a lawsuit that seeks to compel EPA to issue methane performance standards for existing sources in the oil and natural gas source category. 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. The rule seeks to minimize venting and flaring of emissions from storage tanks and other equipment, and also to impose leak detection and repair requirements. In December 2017, the BLM issued a final rule temporarily suspending implementation of the rule until January 2019; however, in February 2018, a federal district court issued a preliminary injunction prohibiting BLM from enforcing the stay. As a result, the November 2016 rules, as originally promulgated, is in effect. Separately, also in February 2018, the BLM proposed a rule to rescind the agency s 2016 methane rule. Additional litigation related to the proposed rescission is likely. 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 the 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. Moreover, activists concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and gas will continue to represent a substantial percentage of global energy use over that time. 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, the EPA published final CAA regulations in 2012 and, more recently, in June 2016 governing CAA performance standards, including standards for the capture of air emissions released during oil and natural gas hydraulic fracturing, leak detection, and permitting and separately published in June 2016 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. The BLM s rescission of the rule has been challenged by several environmental groups and states in the U.S. District Court for the Northern District of California.

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.

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 June 30, 2018, we had $284.6 million of debt outstanding, with a weighted average interest rate of 4.83%, and a 1.0% increase in interest rates would result in an increase in annual interest expense of $2.8 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.

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.

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

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 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) and 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 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 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 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, 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 the Company s annual or interim financial statements will not be prevented or detected on a timely basis.

We have identified five material weaknesses in our internal control over financial reporting. The material weaknesses identified relate to an overall lack of qualified personnel within the organization who possessed an appropriate level of expertise, experience and training to effectively design, implement and maintain: (i) adequate controls to monitor and assess the control environment; specifically, internal controls were not designed or operating effectively to ensure appropriate monitoring or assessment of the control environment, including utilizing an appropriate control framework; (ii) adequate controls to establish appropriate entity level controls; specifically, internal controls were not designed or operating effectively to ensure a sufficient amount of entity level controls were in place and operating effectively; (iii) effective controls over our period-end financial reporting processes, including controls over the preparation, analysis and review of certain significant account reconciliations required to assess the appropriateness of account balances at period-end; and controls over segregation of duties and the review of manual journal entries; specifically, the Company 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; and 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, they 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 Company 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; and these deficiencies, 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; and (v) 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 originated with Citizen, the predecessor of Roan LLC, which had a lack of sufficient resources and inadequate control systems as it commenced operations as a private company. These material weaknesses did not result in any material misstatements of the Company s financial statements or disclosures. The control deficiencies discussed above could 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. Accordingly, our management has determined that these control deficiencies constitute material weaknesses.

We have taken and will continue to take a number of actions to remediate these material weaknesses. We are currently implementing measures designed to improve our internal control over financial reporting and remediate the control deficiencies that led to the material weaknesses, including but not limited to, (i) hiring additional IT and accounting personnel with appropriate technical skillsets, (ii) initiating design and implementation of our control environment, including the expansion of formal accounting and IT policies and procedures and financial reporting controls, (iii) conducting a company-wide assessment of our control environment, (iv) implementing appropriate review and oversight responsibilities within the accounting and financial reporting functions, and (v) evaluating controls over our information technology environment. We can give no assurance that these actions will remediate these material weaknesses in internal controls or that additional material weaknesses in our internal control over financial reporting will not be identified in the future. 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 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 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 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 Common Stock, you could lose a substantial part or all of your investment in our Common Stock. Consequently, you may not be able to sell shares of our 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 Common Stock;
- sales of our Common Stock by us or our principal 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 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 will beneficially own approximately 75% (50% of which is beneficially owned by Roan Holdings) of our outstanding Common Stock. Consequently, they will continue to have significant influence over all matters that require approval by our stockholders, including the election of directors and approval of significant corporate transactions. Because our board will be classified through the 2020 annual meeting, certain of our directors will not come up for election until after the 2020 annual meeting. This concentration of ownership and the rights of our principal stockholders will limit your ability to influence corporate matters, and as a result, actions may be taken that you may not view as beneficial.

In connection with the Reorganization, we entered into a stockholders agreement with the principal stockholders. The stockholders agreement provides the principal stockholders with the right to designate a certain number of nominees to our Board 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 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 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 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 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.

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 will 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 will, among other things:

- permit 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

- provide 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 the Company s Securities.

Our second amended and restated certificate of incorporation and second amended and restated bylaws, as well as Delaware law, will contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our Common Stock.

Our second amended and restated certificate of incorporation will authorize our Board to issue preferred stock without stockholder approval. If our Board 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 to be acted upon at meetings of stockholders;
- providing that the Board 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 or for proposing matters that can be acted upon by stockholders at stockholder meetings.

Our second amended and restated certificate of incorporation will designate 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 will provide 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 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 Common Stock appreciates.

We do not plan to declare cash dividends on shares of our 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 Common Stock at a price greater than you paid for it. There is no guarantee that the price of our Common Stock that will prevail in the market will ever exceed the price that you paid for it.

Future sales of our 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 Common Stock in one or more future public offerings. We may also issue additional shares of Common Stock or securities convertible into Common Stock. We have 152,539,532 outstanding shares of Common Stock. Under our second amended and restated certificate of incorporation, we will be authorized to issue 800,000,000 shares of Common Stock and 50,000,000 shares of preferred stock with such designations, preferences and rights as determined by our Board. The potential issuance of such additional shares of equity securities will result in the dilution of the ownership interests of the holders of our Common Stock and may create downward pressure on the trading price, if any, of our Common Stock. The registration rights of the principal stockholders and the sales of substantial amounts of our 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 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 Common Stock or securities convertible into Common Stock or the effect, if any, that future issuances and sales of shares of our Common Stock will have on the market price of our Common Stock. Sales of substantial amounts of our Common Stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our Common Stock.

We may issue preferred stock the terms of which could adversely affect the voting power or value of our Common Stock.

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

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

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

Selected Historical Financial Information

Roan Inc. was incorporated to serve as a holding company and, prior to the Reorganization, had no previous operations, assets or liabilities. The historical financial statements included in this Current Report are the financial statements of Roan LLC, our accounting predecessor, and the historical financial and operating information of Roan LLC presented in this Current Report, (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 operating information of Citizen prior to August 31, 2017 does not include financial information relating to the Linn Contributed Business.

The following selected historical financial data was derived from the unaudited and audited historical financial statements of Roan LLC, our accounting predecessor, included as Exhibits 99.1 and 99.2 to this Current Report. 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 financial statements of our accounting predecessor, Roan LLC, and accompanying notes included as Exhibits 99.1 and 99.2 to this Current Report.

	Six Months Ended June 30, 2018 (Unaudited)	Six Months Ended June 30, 2017 (Unaudited)	Year Ended December 31, 2017(1)	Year Ended December 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014(2) (Unaudited)
	(In thousands, except per unit amounts)					
Statement of Operations Data:						
Revenues(3):						
Oil	$ 122,369	$ 29,001	$ 76,876	$ 30,565	$ 3,972	$ 65
Natural gas	30,897	18,039	49,211	16,093	1,055	115
Natural gas liquids	38,271	11,975	40,298	8,307	658	26
(Loss) gain on derivative contracts	(64,216)	2,254	(6,797)			
Total revenues	127,321	61,269	159,588	54,965	5,685	206
Operating Expenses(3):						
Production expenses	15,374	6,114	16,872	5,090	549	83
Gathering, transportation and processing		6,470	18,602	5,920	273	6
Production taxes	4,682	1,210	3,685	1,087	190	12
Exploration expenses	18,483	246	32,629	5,258	121	24
Depreciation, depletion, amortization and accretion	46,466	11,352	37,376	24,996	2,091	66
General and administrative	27,106	17,573	31,357	5,581	2,074	344
Gain on sale of oil and natural gas properties			(838)			
Total operating expenses	112,111	42,965	139,683	47,932	5,298	535
Operating income (loss)	15,210	18,304	19,905	7,033	387	(329)
Other income (expense):						
Interest expense	(2,886)	(177)	(1,461)	(86)		
Other income			13		4	2
Total other income (expense)	(2,886)	(177)	(1,448)	(86)	4	2
Net income (loss)	$ 12,324	$ 18,127	$ 18,457	$ 6,947	$ 391	(327)
Pro Forma Data (Unaudited)(4):						
Pro forma net income	$ 9,152		$ 33,323			
Pro forma net income per share:						
Basic and diluted	$ 0.06		$ 0.22			
Pro forma weighted average shares outstanding:						
Basic and diluted	152,540		152,122			
Balance Sheet Data (at period end):						
Total assets	$ 2,269,811		$ 1,885,592	$ 363,083	$ 113,053	$ 16,618
Total liabilities	$ 627,685		$ 300,823	$ 88,836	$ 14,761	$ 1,492
Total members equity	$ 1,642,126		$ 1,584,769	$ 274,247	$ 98,292	$ 15,126
Other Financial Data:						

Adjusted EBITDAX(5)	$ 135,214	$ 27,778	$ 97,549	$ 37,287	$ 2,603	$ (237)
Net Debt(5)	$ 260,263		$ 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 six months ended June 30, 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 income tax expense of $3.2 million and $11.6 million for the six months ended June 30, 2018 and the year ended December 31, 2017, respectively, associated with the income tax effects of the Reorganization described under Introductory Note. Roan Resources, Inc. is taxable as a corporation under the Internal Revenue Code of 1986, as amended (the Code), and as a result, will be subject to U.S. federal, state and local income taxes. Our accounting predecessor, Roan LLC, passed through its taxable income to its owners for other income tax purposes and thus was not subject to U.S. federal or state income taxes.

(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 and a reconciliation of Net Debt to long-term debt, please see Non-GAAP Financial Measure below.

Non-GAAP Financial Measure

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 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, and non-cash (gain) loss on derivative contracts. Adjusted EBITDAX is not a measure of net income as determined by GAAP. Our accounting 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.

Management believes Adjusted EBITDAX is useful because it allows it to more effectively evaluate the operating performance and compare the results of its operations from period to period without regard to its financing methods or capital structure. We add the items listed above to net income in arriving at Adjusted EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income 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, 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.

	Six Months Ended June 30,		**Year Ended December 31,**			
	2018	**2017**	**2017**	**2016**	**2015**	**2014**
	(in thousands)					
Adjusted EBITDAX reconciliation to net income (loss):						

Net income (loss)	$ 12,324	$ 18,127	$ 18,457	$ 6,947	$ 391	$ (327)
Interest expense	2,886	177	1,461	86		
Exploration expense	18,483	246	32,629	5,258	121	24
Non-cash equity-based compensation expense	5,127		379			
Depletion, depreciation, amortization and accretion	46,466	11,352	37,376	24,996	2,091	66
Non-cash loss (gain) on derivatives contracts	50,305	(2,124)	9,502			

	Six Months Ended June 30, 2018	2017	Year Ended December 31, 2017	2016	2015	2014
	(in thousands)					
Gain on early termination of derivative contracts	(377)		(2,255)			
Adjusted EBITDAX	$ 135,214	$ 27,778	$ 97,549	$ 37,287	$ 2,603	$ (237)

	As of June 30, 2018	As of December 31, 2017	2016
	(in thousands)		
Net Debt reconciliation to long-term debt:			
Long-term debt	$ 284,639	$ 85,339	$ 20,000
Cash	24,376	1,471	6,853
Net Debt	$ 260,263	$ 83,868	$ 13,147

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.

Unaudited Pro Forma Condensed Combined Financial Information

The unaudited pro forma condensed financial information of the Company as of June 30, 2018, for the six months ended June 30, 2018 and for the year ended December 31, 2017 is attached to this Current Report as Exhibit 99.4 and is incorporated herein by reference. This pro forma financial information gives effect to the (i) Reorganization, including becoming a taxable entity and (ii) contribution of certain oil and natural gas assets to us by Old Linn.

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 Financial Data and the accompanying financial statements and related notes included elsewhere in this Current Report, including the exhibits hereto. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are subject to risk and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the development, production, gathering and sale of oil, natural gas and NGLs. Please refer to Risk Factors and Cautionary Statement Regarding Forward-Looking Statements for additional information regarding these risks and uncertainties. In light of these risks and uncertainties, the forward-looking events discussed may not occur. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

Overview

We are an independent oil and natural gas company with a primary focus on the development of our assets throughout the Merge, SCOOP and STACK plays of the 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 producing oil and natural gas basins in the United States.

Our assets consist of over 150,000 net acres in the Merge, SCOOP and STACK plays within the Anadarko Basin. We focus our development on formations where we believe we can apply our technical and operational expertise in order to increase proved reserves and production to deliver compelling economic rates of return on a risk adjusted basis.

Our primary developmental focus is on our Merge acreage position in Canadian, Grady and McClain counties in Central Oklahoma, where we have over 115,000 net acres. Our acreage position is concentrated in the oil and liquids-rich fairways of the Merge play, and provides us development opportunities through multiple stacked development horizons. We believe these development horizons have been substantially de-risked through industry development of over approximately 300 horizontal wells. Our acreage position throughout the Merge is largely held by production, has a high average working interest and is predominantly contiguous, providing us with a high degree of operational control and development flexibility.

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 $74.15 per Bbl and $3.20 per MMBtu, respectively, during the first half of 2018. 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.

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 150,000 acres in the Merge, SCOOP and STACK plays within the Anadarko Basin. As of June 30, 2018, we operated six rigs across all of our properties and added two more rigs in the third quarter of 2018. Our primary developmental focus area across this acreage is within the Merge play. As of June 30, 2018, we operated 556 gross wells and had an interest in an additional 590 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;

acquisition and development expenditures; and

Adjusted EBITDAX.

Please see Sources of Revenue, Production Volumes, Principal Components of Our Cost Structure and Non-G. Financial Measures 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. Our revenues from oil, natural gas and NGLs sales do not include the effects of derivatives. For the year ended December 31, 2017, our revenues, excluding loss on derivative contracts, were derived 46% from oil sales, 30% from natural gas sales and 24% from NGLs sales. For the six months ended June 30, 2018, our revenues, excluding loss on derivative contracts, were derived 64% from oil sales, 16% from natural gas sales and 20% from NGLs sales. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

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 comparable periods of 2018 measured against 2017. The following table sets forth the Company s average oil and natural gas prices received on the oil, natural gas and NGL production sold for the years ended December 31, 2017, 2016 and 2015 and the six months ended June 30, 2018 and 2017:

	Six Months Ended June 30,		Year Ended December 31,		
	2018	**2017**	**2017**	**2016**	**2015**
Average prices(1):					
Oil (per Bbl)	$ 63.90	$ 54.06	$ 52.87	$ 41.72	$ 40.97
Natural gas (per Mcf)	$ 1.71	$ 3.10	$ 2.80	$ 2.57	$ 2.45
NGLs (per Bbl)	$ 21.78	$ 23.67	$ 26.44	$ 15.26	$ 13.71
Total realized price per Boe	$ 28.66	$ 29.34	$ 28.16	$ 23.70	$ 26.32
Average realized prices after effects of derivative settlements(1)(2):					
Oil (per Bbl)	$ 55.70	$ 54.06	$ 53.57	$ 41.72	$ 40.97
Natural gas (per Mcf)	$ 1.81	$ 3.12	$ 2.89	$ 2.57	$ 2.45
NGLs (per Bbl)	$ 21.78	$ 23.67	$ 26.44	$ 15.26	$ 13.71
Total realized price per Boe	$ 26.58	$ 29.41	$ 28.60	$ 23.70	$ 26.32

(1) Average prices for the six months ended June 30, 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, 2017, 2016 and 2015 and the six months ended June 30, 2018 and 2017:

	Six Months Ended June 30,		Year Ended December 31,		
	2018	2017	2017	2016	2015
Total sales volumes:					
Oil (MBbls)	1,915	536	1,454	733	97
Natural gas (MMcf)	18,069	5,814	17,582	6,252	430
NGLs (MBbls)	1,757	506	1,524	544	48
Total (MBoe)	6,684	2,011	5,908	2,319	216
Average daily total volumes (MBoe)	36.9	11.1	16.2	6.4	0.6

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. As of June 30, 2018 and December 31, 2017, 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 June 30, 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 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 NGLs 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 and amortization. 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 of asset retirement obligation. We record the fair value of the legal liability for an asset retirement obligation (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 Asset Retirement Obligation 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 full cost 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 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, and non-cash (gain) loss on derivative contracts. Please see Selected Historical Financial Information Adjusted EBITDAX and Net Debt for a discussion on this metric. Our accounting 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.

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

Corporate Reorganization

Roan Resources, Inc. was incorporated to serve as a holding company and, prior to the Reorganization, had no previous operations, assets or liabilities. Roan LLC became our wholly owned subsidiary as part of the Reorganization. For more information on our Reorganization and the ownership of our Common Stock by our principal stockholders, please see Introductory Note and Security Ownership of Certain Beneficial Owners and Management and the unaudited pro forma financial statements included as Exhibit 99.4 to this Current Report.

The historical financial statements included in this Current Report are the financial statements of Roan LLC, our accounting predecessor, and the historical financial and operating information of Roan LLC presented in this Current Report, (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 operating 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 Current Report treats the Reorganization as if the Reorganization happened on January 1, 2017. As a result, the historical financial data and pro forma financial information presented in this Current Report 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

In anticipation of the Reorganization, we began incurring direct, incremental G&A expenses with a view to becoming a publicly traded company. The incremental costs have or will in the future include costs associated with hiring new personnel, Sarbanes-Oxley compliance, implementation of compensation programs that are competitive with our public company peer group, costs associated with annual and quarterly reports and our other filings with the SEC, exchange listing fees, tax return preparation, independent auditor fees, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs and independent director compensation. These direct, incremental G&A expenses are not included in our historical results of operations.

Income Taxes

Roan Resources, Inc. is a corporation that is subject to U.S. federal, state and local income taxes. Roan LLC has historically passed through its taxable income to its owners for U.S. federal and state and local income tax purposes and thus was not subject to U.S. federal income taxes or other state or local income taxes. Accordingly, the financial data attributable to Roan LLC contains no provision for U.S. federal income taxes or income taxes in any state or locality.

Historical Results of Operations and Operating Expenses

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

	For the Six Months Ended June 30,	
	2018	**2017**
Production Data:		
Oil (MBbls)	1,915	536
Natural gas (MMcf)	18,069	5,814
Natural gas liquids (MBbls)	1,757	506
Total volumes (MBoe)	6,684	2,011
Average daily total volumes (MBoe/d)	36.9	11.1
Average Prices as reported(1):		
Oil (per Bbl)	$ 63.90	$ 54.06
Natural gas (per Mcf)	$ 1.71	$ 3.10
Natural gas liquids (per Bbl)	$ 21.78	$ 23.67
Total (per Boe)	$ 28.66	$ 29.34
Average Prices including impact of derivative contract settlements(1)(2):		
Oil (per Bbl)	$ 55.70	$ 54.06
Natural gas (per Mcf)	$ 1.81	$ 3.12
Natural gas liquids (per Bbl)	$ 21.78	$ 23.67
Total (per Boe)	$ 26.58	$ 29.41

(1) Average prices for the six months ended June 30, 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.

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 Six Months Ended June 30,	
	2018	2017
	(in thousands)	
Revenues		
Oil sales	$ 122,369	$ 29,001
Natural gas sales(1)	30,897	18,039
Natural gas liquid sales(1)	38,271	11,975
(Loss) gain on derivative contracts	(64,216)	2,254
Total revenues	$ 127,321	$ 61,269

(1) Revenue for the six months ended June 30, 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 $93.4 million, or 322%, to $122.4 million for the six months ended June 30, 2018 from $29.0 million for the six months ended June 30, 2017. This increase was primarily due to increased production as well as an increase in average sales prices received for our produced volumes. Our oil production increased by 1,379 MBbls, or 257%, to 1,915 MBbls for the six months ended June 30, 2018 from 536 MBbls for the six months ended June 30, 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 second half of 2017 and continuing into 2018. The increase in average sales prices received on our oil production for the six months ended June 30, 2018 reflects the increase in the index price in the 2018 period as compared to the 2017 period.

Natural Gas Sales. Our natural gas sales increased by approximately $12.9 million, or 71%, to $30.9 million for the six months ended June 30, 2018 from $18.0 million for the six months ended June 30, 2017. This increase was primarily due to increased production partially offset by a decrease in average sales prices received for our produced volumes and the impact of netting transportation costs with revenue as a result of adopting ASC 606. Our natural gas production increased by 12,255 MMcf, or 211%, to 18,069 MMcf for the six months ended June 30, 2018 from 5,814 MMcf for the six months ended June 30, 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 second half of 2017 and continuing into 2018. The decrease in average sales prices received on our natural gas production for the six months ended June 30, 2018 reflects the decrease in natural gas prices in the 2018 period as compared to the 2017 period.

NGL Sales. Our NGL sales increased by approximately $26.3 million, or 220%, to $38.3 million for the six months ended June 30, 2018 from $12.0 million for the six months ended June 30, 2017. This increase was primarily due to increased production as well as an increase in average sales prices received for our produced volumes, partially offset by the impact of netting transportation costs with revenue as a result of adopting ASC 606. Our NGL production increased by 1,251 MBbls, or 247%, to 1,757 MBbls for the six months ended June 30, 2018 from 506 MBbls for the six months ended June 30, 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 second half of 2017 and continuing into 2018.

(Loss) gain on derivative contracts. For the six months ended June 30, 2018, changes in oil prices had a negative impact on the fair value and settlement of our derivative contracts. We had a loss on derivative contracts of $64.2 million, including loss on settlement of derivatives contracts of $13.9 million and unfavorable change in the fair value of derivative contracts of $50.3 million. The change in the fair value was primarily driven by higher oil prices, which resulted in our open oil derivative contracts being in a liability position as of June 30, 2018. For the six months ended June 30, 2017, there was a gain on derivative contracts of $2.25 million, including a gain on settlement of derivative contracts of $0.1 million and a favorable change in the fair value of derivative contracts of $2.1 million. The change in the fair value was primarily driven by lower oil and natural gas prices, which resulted in our open derivative contracts being in an asset position as of June 30, 2017.

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 Six Months Ended June 30,	
	2018	2017
	(in thousands, except per Boe)	
Operating Expenses		
Production expenses	$ 15,374	$ 6,114
Gathering, transportation and processing(1)		6,470
Production taxes	4,682	1,210
Exploration expenses	18,483	246
Depreciation, depletion, amortization and accretion	46,466	11,352
General and administrative (2)	27,106	17,573
Total	$ 112,111	$ 42,965
Average Costs per Boe:		
Production expenses	$ 2.30	$ 3.04
Gathering, transportation, and processing		3.22
Production taxes	0.70	0.60
Exploration expenses	2.77	0.12
Depreciation, depletion, amortization and accretion	6.95	5.64
General and administrative (1)	4.06	8.74
Total	$ 16.78	$ 21.36

(1) Gathering, transportation and processing for the six months ended June 30, 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 six months ended June 30, 2018 include $5.1 million, or $0.77 per Boe, of equity-based compensation expense.

Production expenses. Production expenses were $15.4 million, or $2.30 per Boe, for the six months ended June 30, 2018, which was an increase of $9.3 million, or 153%, from $6.1 million, or $3.04 per Boe, for the six months ended June 30, 2017. The increase in production expenses during 2018 compared to 2017 was primarily due to increased production. Due to certain production expenses being fixed, the increased production resulted in a decrease in production expense per Boe. Additionally, we achieved costs efficiencies beginning in May 2018 following our becoming operator of the oil and natural gas properties contributed to us by Citizen and Old Linn as a result of our concentrated acreage position.

Gathering, transportation and processing. Gathering, transportation, and processing costs were $6.5 million, or $3.22 per Boe, for the six months ended June 30, 2017. As a result of adopting ASC 606 in January 2018, these costs are reflected as a deduction from revenue for the six months ended June 30, 2018.

Production taxes. Production taxes were $4.7 million for the six months ended June 30, 2018, an increase of $3.5 million, or 287%, from $1.2 million for the six months ended June 30, 2017. Production taxes primarily increased due to increased revenues.

Exploration expenses. For the six months ended June 30, 2018, exploration expenses of $18.5 million consisted of unproved leasehold amortization of $14.5 million and geological and geophysical expenses of $4.0 million.

For the six months ended June 30, 2017, exploration expenses of $0.2 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 2018.

Depreciation, depletion, amortization and accretion. Depreciation, depletion, amortization and accretion was $46.5 million, or $6.95 per Boe, for the six months ended June 30, 2018, and $11.4 million, or $5.64 per Boe, for the six months ended June 30, 2017, which is an increase of $35.1 million, or 309%. 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.

General and administrative. General and administrative expenses were $27.1 million, or $4.06 per Boe, for the six months ended June 30, 2018, an increase of $9.5 million, or 54%, from $17.6 million, or $8.74 per Boe, for the six months ended June 30, 2017. During the six months ended June 30, 2018, general and administrative expenses included equity-based compensation expense of $5.1 million and fees paid to Citizen and Old Linn under the MSAs of $10.0 million. There were no such expenses incurred in the six months ended June 30, 2017. Additionally, we incurred consulting and professional fees as part of the implementation of systems and processes and transition efforts. These expenses were offset by bonuses paid by Citizen of approximately $9.0 million during the six months ended June 30, 2017. Our MSAs with Citizen and Old Linn concluded in April 2018.

Other Expenses

Interest expense, net. Interest expense, net of capitalized interest, for the six months ended June 30, 2018 was $2.9 million as compared to $0.2 million for the six months ended June 30, 2017. This increase was due to increased borrowings outstanding during the six months ended June 30, 2018 as compared to the six months ended June 30, 2017.

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	733
Natural gas (MMcf)	17,582	6,252
Natural gas liquids (MBbls)	1,524	544
Total volumes (MBoe)	5,908	2,319
Average daily total volumes (MBoe/d)	16.2	6.4
Average Prices as reported:		
Oil (per Bbl)	$ 52.87	$ 41.72
Natural gas (per Mcf)	$ 2.80	$ 2.57
Natural gas liquids (per Bbl)	$ 26.44	$ 15.26
Total (per Boe)	$ 28.16	$ 23.70
Average Prices including impact of derivative contract settlements(1):		
Oil (per Bbl)	$ 53.57	$ 41.72
Natural gas (per Mcf)	$ 2.89	$ 2.57
Natural gas liquids (per Bbl)	$ 26.44	$ 15.26
Total (per Boe)	$ 28.60	$ 23.70

(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 721 MBbls, or 98%, 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 11,330 MMcf, or 181%, 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 980 MBbls, or 180%, 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 $2.3 million gain on the settlement of derivative contracts prior to their contractual maturity. There were no derivative contracts in place during the year ended December 31, 2016.

Operating Expenses

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

	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

	For the Year Ended December 31, 2017	2016
	(in thousands, except per Boe)	
Gain on sale of oil and natural gas properties	(838)	
Total	$ 139,683	$ 47,932
Average Costs per Boe:		
Production expenses	$ 2.86	$ 2.19
Gathering, transportation and processing	3.15	2.55
Production taxes	0.62	0.47
Exploration expenses	5.52	2.27
Depreciation, depletion, amortization and accretion	6.33	10.78
General and administrative(1)	5.31	2.41
Gain on sale of oil and natural gas properties	(0.14)	
Total	$ 23.65	$ 20.67

(1) General and administrative expenses for the year ended December 31, 2017 include $0.3 million, or $0.06 per Boe, of equity-based compensation expense.

Production expenses. Production expenses are the operating costs incurred to maintain production. Such costs include the cost of saltwater disposal, monitoring, pumping, chemicals, maintenance, repairs, workover expenses and direct labor and overhead related to production activities. 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 $2.19 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. These costs are incurred to get natural gas and NGLs to market. 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 $2.55 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 are paid on produced oil, natural gas, and NGLs based primarily on a percentage of sales revenues from production sold at fixed rates established by federal, state or local taxing authorities. 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. 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. For the year ended December 31, 2017, exploration expenses of $32.6 million consisted of unproved leasehold amortization of $25.4 million and geological and geophysical expenses of $7.2 million. Unproved leasehold amortization is calculated by considering our drilling plans and the lease terms of our existing unproved properties. 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 2018.

Depreciation, depletion, amortization and accretion. Depreciation, depletion, amortization and accretion was $37.4 million, or $6.33 per Boe, for the year ended December 31, 2017, which was an increase of $12.4 million, or 50%, from $25.0 million, or $10.78 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 $2.41 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.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

	For the Year Ended December 31,	
	2016	**2015**
Production Data:		
Oil (MBbls)	733	97
Natural gas (MMcf)	6,252	430
Natural gas liquids (MBbls)	544	48
Total volumes (MBoe)	2,319	216
Average daily total volumes (MBoe/d)	6.4	0.6
Average Prices as reported:		
Oil (per Bbl)	$ 41.72	$ 40.97
Natural gas (per Mcf)	$ 2.57	$ 2.45
Natural gas liquids (per Bbl)	$ 15.26	$ 13.71
Total (per Boe)	$ 23.70	$ 26.32

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,	
	2016	**2015**
Revenues		
Oil sales	$ 30,565	$ 3,972
Natural gas sales	16,093	1,055
Natural gas liquid sales	8,307	658
Total revenues	$ 54,965	$ 5,685

Oil sales. Our oil sales increased by approximately $26.6 million, or 670%, to $30.6 million for the year ended December 31, 2016 from $4.0 million for the year ended December 31, 2015. This increase was primarily due to increased production. Our oil production increased by 636 MBbls, or 656%, for the year ended December 31, 2016 compared with the year ended December 31, 2015. The increase in production volumes was due to drilling activity in 2016.

Natural Gas sales. Our natural gas sales increased by approximately $15.0 million, or 1,425%, to $16.1 million for the year ended December 31, 2016 from $1.1 million for the year ended December 31, 2015. This increase was primarily due to increased production. Our natural gas production increased by 5,822 MMcf, or 1,354%, for the year ended December 31, 2016 compared with the year ended December 31, 2015. The increase in production volumes was due to drilling activity in 2016.

NGL sales. Our NGL sales increased by approximately $7.6 million, or 1,162%, to $8.3 million for the year ended December 31, 2016 from $0.7 million for the year ended December 31, 2015. This increase was primarily due to increased production. Our NGL production increased by 496 MBbls, or 1,033%, for the year ended December 31, 2016 compared with the year ended December 31, 2015. The increase in production volumes was due to drilling activity in 2016.

Operating Expenses

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

	For the Year Ended December 31,			
	2016		2015	
	(in thousands, except per Boe)			
Operating Expenses				
Production expenses	$	5,090	$	549
Gathering, transportation and processing		5,920		273
Production taxes		1,087		190
Exploration expenses		5,258		121
Depreciation, depletion, amortization and accretion		24,996		2,091
General and administrative		5,581		2,074
Total	$	47,932	$	5,298
Average Costs per Boe:				
Production expenses	$	2.19	$	2.54
Gathering, transportation and processing		2.55		1.26
Production taxes		0.47		0.88
Exploration expenses		2.27		0.56
Depreciation, depletion, amortization and accretion		10.78		9.68
General and administrative		2.41		9.60
Total	$	20.67	$	24.52

Production expenses. Production expenses were $5.1 million, or $2.19 per Boe, for the year ended December 31, 2016, which was an increase of $4.6 million, or 827%, from $0.5 million, or $2.54 per Boe, for the year ended December 31, 2015. The increase in production expenses during 2016 compared to 2015 was primarily due to increased production. Due to certain production expenses being fixed, the increased production resulted in a decrease in production expenses per Boe.

Gathering, transportation and processing. Gathering, transportation, and processing costs were $5.9 million, or $2.55 per Boe, for the year ended December 31, 2016, which was an increase of $5.6 million, or 2,068%, from $0.3 million, or $1.26 per Boe, for the year ended December 31, 2015. The increase in gathering, transportation and processing costs during 2016 as compared to 2015 was primarily related to increased production.

Production taxes. Production taxes were $1.1 million for the year ended December 31, 2016, an increase of $0.9 million, or 472%, from $0.2 million for the year ended December 31, 2015. Production taxes primarily increased due to increased revenues.

Exploration expenses. For the year ended December 31, 2016 and 2015, exploration expenses of $5.3 million and $0.1 million, respectively, consisted of impairment expense recognized related to our unproved properties.

Depreciation, depletion, amortization and accretion. Depreciation, depletion, amortization and accretion was $25.0 million, or $10.78 per Boe, for the year ended December 31, 2016, which was an increase of $22.9 million, or 1,095%, from $2.1 million, or $9.68 per Boe, for the year ended December 31, 2015. The increase in depreciation, depletion, amortization and accretion was primarily due to increased production.

General and administrative. General and administrative expenses were $5.6 million, or $2.41 per Boe, for the year ended December 31, 2016, which was an increase of $3.5 million, or 169%, from $2.1 million, or $9.60 per Boe, for the year ended December 31, 2015. The increase in general and administrative expenses was primarily due to additional administrative costs, including compensation for additional staff, incurred as a result of increased drilling and leasing activity in 2016.

Liquidity and Capital Resources

Overview

Our primary sources of liquidity to date have been borrowings under our credit facility and cash flows from operations. To date, our primary use of capital has been for the acquisition, exploration and development of proved and unproved oil and natural gas properties. Based upon the current commodity price and production expectations, we believe our cash on hand, cash flow from operations, and borrowings under our credit facility, including anticipated availability based on redeterminations of our borrowing base, will be sufficient to fund our operations for the next twelve months. Long-term cash flows are subject to a number of variables including the level of production and prices (as impacted by our hedging activities) we receive for our production as well as various economic conditions that have historically affected the oil and natural gas business. There can be no assurance that internal cash flows and other capital sources will provide sufficient funds to maintain capital expenditures that we believe are necessary to offset inherent declines in production and proven reserves.

Subject to compliance with related covenants in our credit facility, we plan to continue our practice of entering into hedging arrangements to reduce the impact of commodity price volatility on our cash flow from operations. Under this strategy, we expect to maintain an active hedging program that seeks to reduce our exposure to commodity prices and protect our cash flow.

Because we are the operator of a high percentage of our acreage, 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.

As of June 30, 2018, our borrowing base under our credit facility was $425.0 million. As of June 30, 2018, we had $284.6 million of outstanding borrowings under our credit facility and no outstanding letters of credit. Subject to changes in commodity prices, we would expect the available borrowing capacity under our credit facility to increase as we convert proved undeveloped reserves to proved developed producing reserves, which may provide us additional borrowing capacity in the future.

Cash Flows

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

	Six Months Ended June 30,		Year Ended December 31,		
	2018	**2017**	**2017**	**2016**	**2015**

	(unaudited)				
			(in thousands)		
Net cash provided by operating activities	$ 164,530	$ 28,034	$ 60,275	$ 36,140	$ 4,637
Net cash used in investing activities	(339,968)	(96,701)	(212,521)	(241,109)	(66,181)
Net cash provided by financing activities	198,343	80,383	146,864	189,008	82,775
Net increase (decrease) in cash and cash equivalents	$ 22,905	$ 11,716	$ (5,382)	$ (15,961)	$ 21,231

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Analysis of Cash Flow Changes Between the Six Months Ended June 30, 2018 and 2017

Cash flows from operating activities. Cash flows from operating activities for the six months ended June 30, 2018 were inflows of $164.5 million compared to inflows of $28.0 million for the six months ended June 30, 2017. 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 six months ended June 30, 2018 and 2017, we completed acquisitions of oil and natural gas properties of $22.9 million and $38.8 million, respectively. Additionally, we invested $314.7 million and $54.8 million during the six months ended June 30, 2018 and 2017, respectively, for development of oil and natural gas properties.

Cash flows from financing activities. Cash flows from financing activities for the six months ended June 30, 2018, were attributable to borrowings of $199.3 million from our credit facility. Financing activity for the six months ended June 30, 2017 were related to capital contributions of $80.4 million.

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 activity for the year ended December 31, 2016 were related to capital contributions of $169.0 million and $20.0 million of proceeds from borrowings.

Analysis of Cash Flow Changes Between the Year Ended December 31, 2016 and 2015

Cash flows from operating activities. Cash flows from operating activities for the year ended December 31, 2016 were inflows of $36.1 million compared to $4.6 million for the year ended December 31, 2015. 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, 2016 and 2015, we completed acquisitions of oil and natural gas properties of $144.8 million and $47.9 million, respectively. Additionally, we invested $96.3 million and $18.1 million during the years ended December 31, 2016 and 2015, 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, 2016, were attributable to capital contributions of $169.0 million and $20.0 million of proceeds from borrowings. Cash flows from financing activities for the year ended December 31, 2015 consisted of $82.8 million from contributions.

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, financing under our credit facility or the issuance of debt or equity securities.

We currently expect our capital budget for 2018 expenditures relating to our oil and natural gas properties to be approximately $625.0 million to $675.0 million, excluding acquisitions. We expect to allocate the majority of our 2018 capital budget for the drilling and completion of operated wells. During the six months ended June 30, 2018, capital expenditures relating to our oil and natural gas properties were $310.5 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.

Working Capital

At June 30, 2018, we had a working deficit of $106.7 million compared to a working deficit of $121.2 million at December 31, 2017. Current assets and current liabilities increased by $131.3 million and $116.8 million, respectively, at June 30, 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. At the termination of the MSAs in April 2018, we assumed certain working capital accounts associated with these properties from Citizen and Old Linn. Also contributing to the increase in current assets and current liabilities at June 30, 2018 was our increased drilling activity during 2018. The increase in the derivative contract liabilities is related to the negative impact of changes in oil prices on the fair value of our contracts.

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 June 30, 2018, the borrowing base under our existing credit facility was $425.0 million. As of June 30, 2018, we had $284.6 million of borrowings and no letters of credit outstanding under our existing credit facility, with $140.4 million of additional borrowing capacity available.

Borrowings under the credit facility bear interest at a rate equal to, at Roan LLC s option, either (1) a base rate plus an applicable margin ranging between 1.25% per annum and 2.25% per annum, based upon the amount of availability under the borrowing base or (2) a LIBOR rate plus an applicable margin ranging between 2.25% per annum and 3.25% per annum, based upon the amount of availability under the borrowing base.

At June 30, 2018, the weighted average interest rate on borrowings under our existing credit facility was 4.83%. We also pay a commitment fee on unused amounts of our existing credit facility of 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 customary representations and warranties and customary affirmative and negative covenants that 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.

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

As of December 31, 2017 and June 30, 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 June 30, 2018:

	Payments Due by Period						
	2018	**2019**	**2020**	**2021**	**2022**	**Thereafter**	**Total**
				(in thousands)			
Credit Facility	$	$	$	$	$ 284,639	$	$ 284,639
Interest expense related to Credit Facility (1)	7,025	13,934	13,934	13,934	9,468		58,295
Pipe and equipment purchase commitments (2)	2,447						2,447
Office building leases	616	1,553	2,015	2,079	2,147	612	9,022
Drilling rig commitments (3)	17,908	15,351					33,259
Total contractual obligations and commitments	$ 27,996	$ 30,838	$ 15,949	$ 16,013	$ 296,254	$ 612	$ 387,662

(1) Includes interest expense on our outstanding borrowings calculated using the weighted average interest rate of 4.83% at June 30, 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 following table summarizes our contractual obligations and commitments as of December 31, 2017:

	Payments Due by Period						
	2018	2019	2020	2021	2022	Thereafter	Total
	(in thousands)						
Credit Facility	$	$	$	$	$ 85,339	$	$ 85,339
Interest expense related to Credit Facility (1)	3,487	3,487	3,487	3,487	2,369		16,317
Drilling rig commitments (3)	5,140						5,140
Total contractual obligations and commitments	$ 8,627	$ 3,487	$ 3,487	$ 3,487	$ 87,708	$	$ 106,796

(1) Includes interest expense on our outstanding borrowings calculated using the weighted average interest rate of 4.03% at December 31, 2017.

(2) Reflects future minimum drilling fees including early termination fees as specified by the contract.

The above tables do 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.

Commodity Price Risk

The following table provides a summary of our open commodity contracts at June 30, 2018:

	2018	2019	2020	Total
Oil fixed price swaps				
Volume (Mbbl)	2,576	4,608	410	7,594
Weighted-average price per bbl	$ 57.45	$ 58.66	$ 60.19	$ 58.33
Natural gas fixed price swaps				
Volume (Bbtu)	16,284	21,900	5,005	43,189
Weighted-average price per mmbtu	$ 2.94	$ 2.90	$ 2.69	$ 2.89
Natural gas basis swaps				
Volume (Bbtu)	9,200	10,950		20,150
Weighted-average price per mmbtu	$ 0.54	$ 0.55	$	$ 0.55

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 June 30, 2018, we had a net liability position of $59.8 million related to our derivative contracts. Utilizing actual derivative contractual volumes under our fixed price swaps as of June 30, 2018 an increase of 10% in the forward curves associated with the underlying commodity would have increased the net liability position to $123.0 million, while a decrease of 10% in the forward curves associated with the underlying commodity would have resulted in a net asset position of $1.7 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 June 30, 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 June 30, 2018, we had $284.6 million of debt outstanding, with a weighted average interest rate of 4.83%. 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 $2.8 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 and Note 2 to the unaudited condensed 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. The independent engineering firm, DeGolyer and MacNaughton, prepared the Company s proved reserve estimates as of

December 31, 2017.

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 provided by the Company. 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 the product is delivered at a fixed or determinable price, title and control has transferred and collectability is reasonably assured. We recognize revenues from the sale of oil, natural gas and NGLs using the sales method, whereby revenue is recorded 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, *Revenue from Contracts with Customers (Topic 606)* (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 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 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 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. 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 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 loss on derivative contracts in the accompanying 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 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 Plan). PSUs issued under the Plan 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 equity awards issued subsequent to the reorganization transactions, we will utilize the trading price of our shares. 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. 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.

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, 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 financial statements of Roan LLC since the income tax was an obligation of the members.

Following the Reorganization, the Company 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, 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.

Security Ownership of Certain Beneficial Owners and Management

The following table sets forth the beneficial ownership of our Common Stock as of the Effective Date:

- each person known to us to beneficially own more than 5% of our outstanding Common Stock;
- each of our directors;
- our executive officers; and
- all of our directors and executive officers as a group.

For further information regarding material transactions between us and the persons listed above, please 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 Common Stock outstanding as of the Effective Date.

	Shares Beneficially Owned(1)	
Name of Beneficial Owner	**Number**	**%**
5% Stockholders:		
Roan Holdings(2)	76,269,766	50.0%
Elliott funds (3)	15,794,132	10.4%
Fir Tree funds(4)	14,712,070	9.6%
York Capital funds(5)	9,144,292	6.0%

Directors and Named Executive Officers:		
Tony C. Maranto		
Joel L. Pettit		
Greg T. Condray		
David M. Edwards		
David C. Treadwell		
Matthew Bonanno(5)		
Evan Lederman(4)		
John V. Lovoi(2)(6)	77,604,936	50.9%
Paul B. Loyd, Jr.(2)	76,269,766	50.0%
Michael P. Raleigh(2)	76,269,766	50.0%
Andrew Taylor(3)		
Anthony Tripodo		%
Directors and Executive Officers as a Group (12 Persons)	77,604,936	50.9%

(1) The amounts and percentages of 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 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 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. The sole limited partner of Elliott LP is Elliott International Limited. There is no single beneficial shareholder of Elliott International Limited holding shares equal to 10% or more of its total capital. 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 Elliot 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 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 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 the Company. Mr. Lederman does not have voting and investment power with respect to the shares of 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., (vi) 278,587 shares owned by York Select Strategy Master Fund, L.P. and (vii) 37,332 shares owned by Jorvik Multi-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 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.

Directors and Executive Officers

The following table sets forth the names, ages (as of the Effective Date) and titles of our directors and executive officers. There are no family relationships among any of our directors and executive officers.

Name	Age	Position
Tony C. Maranto	59	President, Chief Executive Officer and Director
Joel L. Pettit	62	Executive Vice President Operations and Marketing
Greg T. Condray	49	Executive Vice President Geoscience and Business Development
David M. Edwards	36	Chief Financial Officer
Amber Bonney	44	Chief Accounting Officer
David C. Treadwell	41	General Counsel and Corporate Secretary
Matthew Bonanno	39	Director
Evan Lederman	38	Director
John V. Lovoi	57	Director
Paul B. Loyd, Jr.	72	Director
Michael P. Raleigh	62	Director
Andrew Taylor	41	Director
Anthony Tripodo	65	Director

Tony C. Maranto has served as our President and Chief Executive Officer since September 2018 and as the President and Chief Executive Officer of Roan LLC since October 2017. Mr. Maranto has over 35 years of experience in the oil and gas industry, having previously worked at EOG Resources, Inc. for 21 years until July 2016. While there, he most recently served as Vice President and General Manager of its Mid-Continent Division for more than a decade. From August 2016 to May 2017, Mr. Maranto served as the Executive Vice President and Chief Operating Officer of EnerVest Operating Company, from May 2017 to June 2017, he served as the Chief Operating Officer of Continental Resources, Inc. and from June 2017 to October 2017, Mr. Maranto had been evaluating potential opportunities prior to joining us. Mr. Maranto graduated from Louisiana Tech University, where he earned a Bachelor of Science degree in Petroleum Engineering. He earned a Master of Business Administration degree from Centenary College.

The Board believes that Mr. Maranto s extensive experience in the energy industry, including his past experiences as an executive with various energy companies, brings valuable strategic, managerial and leadership skills to the Board and us.

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.

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

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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 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. Prior to that, Ms. Bonney served in various capacities, including as controller, at SandRidge Energy, Inc. from March 2008 until May 2014, where she was responsible for the company s financial reporting and involved in a variety of notable transactions, including acquisitions, divestitures, debt and equity offerings and initial public offerings for three royalty trusts. 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. 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 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 Director 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 believes Mr. Bonanno s extensive investment and restructuring experience in the energy industry brings valuable strategic and analytical skills to our Board.

Evan Lederman has served on our Board 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 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.

John V. Lovoi has served on our Board 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 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 Jones Energy, Inc., an oil and gas company. 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 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.

Paul B. Loyd, Jr. has served on our Board 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 has served as an Independent Director of Jones Energy, Inc. since February 5, 2018 and prior to the Reorganization, served on the board of Roan LLC. 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 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.

Michael P. Raleigh has served on our Board 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 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 believes that Mr. Raleigh is qualified to serve as a member of our Board 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 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 believes Mr. Taylor s considerable experience in the investment advisory industry brings substantial investment management skills to the Board.

Anthony Tripodo has served on our Board 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.

The Board 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.

Board of Directors

The Company is traded on the OTCQB, the applicable standards of which do not require the Company to have a majority of independent directors; however, each of Messrs. Tripodo, Bonanno, Lederman, Taylor, Lovoi, Loyd and Raleigh are independent under the independence standards of the NYSE. Mr. Maranto does not meet the independence standards of the NYSE because he is an employee of the Company.

Our Board currently consists of eight members, including our Chief Executive Officer. Pursuant to the Master Reorganization Agreement and Stockholders Agreement, Roan Holdings has the right to appoint one additional director to the Board.

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 s ability to manage and direct our affairs and business, including, when applicable, to enhance the ability of the committees of the Board 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 consists of two classes of directors, with Mr. Maranto 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 will cease to be classified and nominations for director shall be made by the Board upon the advice of the Company s nominating and corporate governance committee.

Meetings of the Board of Directors

Our Board 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. Special meetings of the Board may be called with 24 hours notice to each member (unless waived) upon request of the Chairman of the Board, the Chief Executive Officer or any two members of Board. 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 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 determined that Mr. Maranto should serve as the Chairman of the Board. Additionally, the Board determined that Mr. Tripodo should serve as the lead independent director of the Board.

Director Independence

The Board 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 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 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

The applicable standards of the OTCQB do not require the Company to have a compensation committee or a nominating committee of the board of directors; however, 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, Bonanno and Loyd, with Mr. Tripodo as the Audit Committee s Chairman and audit committee financial expert, as defined by the SEC. The applicable standards of the OTCQB do not contain requirements regarding the composition of the audit committee; however, each member of our audit committee is independent under listing standards of the NYSE and the rules of the SEC.

This committee oversees, reviews, acts on and reports on various auditing and accounting matters to our Board, 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.

Each of the members of the Company s audit committee is financially literate, but the current audit committee does not meet the other requirements contained in NYSE Rule 303A.06 regarding audit committee Composition because

Mr. Loyd is affiliated with Roan Holdings, the owner of greater than 10% of the Company s outstanding Common Stock and thus may be deemed an affiliate under the rule.

Compensation Committee

We have a compensation committee consisting of Messrs. Lovoi, Lederman and Taylor, with Mr. Taylor as the compensation committee s Chairman. The applicable standards of the OTCQB do not contain requirements regarding the composition of the compensation committee; however, 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.

Nominating and Corporate Governance Committee

We have a nominating and corporate governance committee consisting of Messrs. Raleigh, Taylor and Tripodo, with Mr. Raleigh as the nominating and corporate governance committee s Chairman. The applicable standards of the OTCQB do not contain requirements regarding the composition of the nominating and corporate governance committee; however, our board has affirmatively determined that each of Messrs. Raleigh, Taylor 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 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

The Company has adopted a Code of Business Conduct and Ethics, which sets forth legal and ethical standards of conduct for all the Company s employees, as well as the Company s directors. The Company also has adopted a separate code of ethics which applies to the Company s Chief Executive Officer and Senior Financial Officers. All of these documents are available on the Company s website, *www.roanresources.com*, and will be provided free of charge to any shareholder requesting a copy by writing to the Company s 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 the Company s Chief Executive Officer and Senior Financial Officers or if the Company grants any waiver, including any implicit waiver, from a provision of such code, the Company will disclose the nature of such amendment or waiver within four business days on its website. The information on the Company s website is not, and shall not be deemed to be, a part of this filing or incorporated into any other filings the Company makes with the SEC.

Corporate Governance Guidelines

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

Director and Executive Officer 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 during the fiscal year ended December 31, 2017 (the 2017 Fiscal Year). 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 as of our Reorganization. As such, disclosure regarding our executive officers compensation, 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 2017 Fiscal Year. Our Named Executive Officers for the 2017 Fiscal Year include:

Name	Title
Tony C. Maranto	President and Chief Executive Officer
Greg T. Condray	Executive Vice President Geoscience and Business Development
Joel L. Pettit	Executive Vice President Operations and Marketing

David M. Edwards became our Chief Financial Officer on June 18, 2018 and David C. Treadwell became our General Counsel on September 17, 2018 and, as such, neither is included as a Named Executive Officer in this CD&A for the 2017 Fiscal Year.

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.

Elements of Compensation

Base Salaries

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 2017 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. The base salary in effect as of December 31, 2017 for each Named Executive Officer is reflected in the table below:

Name	Base Salary
Tony C. Maranto	$ 525,000
Greg T. Condray	$ 400,000
Joel L. Pettit	$ 350,000

Annual Bonuses

Each Named Executive Officer is eligible to receive an annual bonus in accordance with the terms of his employment agreement. No Named Executive Officer received an annual bonus for the 2017 Fiscal Year.

Long-Term Incentive Compensation

Adoption of the Management Incentive Plan

In order to attract, retain and motivate employees, consultants and directors, the board of managers of Roan LLC adopted the Roan Resources LLC Management Incentive Plan (the Plan). The Plan provides for the grant, from time to time, at the direction of the board of managers of Roan LLC or a committee thereof, of options, unit appreciation rights, restricted units, phantom units, unit awards, distribution equivalents, other unit-based awards, cash awards, substitute awards or performance awards. In connection with the Reorganization, the Plan was amended, restated and renamed the Amended and Restated Plan. Please see Actions Taken Following Fiscal Year End for information on the Amended and Restated Plan.

Performance Share Unit Awards

In connection with the adoption of the Plan and the commencement of each Named Executive Officer s employment, Roan LLC granted PSU awards. 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 the Named Executive Officers to accept their respective offers of employment and provide a retention incentive to remain employed by us throughout the performance period. The PSU awards vest based on company equity value over a three-year performance period commencing on January 1, 2018 and ending December 31, 2020, as set forth in the table below:

Company Value	**Percentage of Target Performance Share Units Earned**	
Below $3,000,000,000	0%	Below Threshold
$3,000,000,000	25%	Threshold
$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

Other Compensation Elements

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.

Actions Taken Following Fiscal Year End

In connection with our Reorganization, the Plan was amended, restated and renamed the Amended and Restated Plan 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 Common Stock such that, to the extent earned, each PSU represents the right to receive one share of 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 Plan in each PSU award agreement were modified to instead refer to the Amended and Restated Plan.

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.

Compensation Committee Report

The compensation committee reviewed and discussed the Compensation Discussion and Analysis required by Item 402 of Regulation S-K promulgated by the SEC with our management, and based on such review and discussions, the compensation committee approved the inclusion of such Compensation Discussion and Analysis in this Current Report.

Compensation Committee of the Board of Directors: Andrew Taylor (chair), John Lovoi, Evan Lederman

2017 Summary Compensation Table

The table below sets forth the annual compensation earned during the 2017 Fiscal Year by our Named Executive Officers:

Name and Principal Position	Year	Salary ($)(1)	Bonus ($)		Unit Awards ($)(3)	Total ($)
Tony C. Maranto	2017	$ 90,865			$ 10,575,000	$ 10,665,865
President and Chief Executive Officer						
Greg T. Condray	2017	$ 53,846	$ 250,000	(2)	$ 3,102,000	$ 3,405,846
Executive Vice President Geoscience and Business Development						
Joel L. Pettit	2017	$ 53,846			$ 2,820,000	$ 2,873,846
Executive Vice President Operations and Marketing						

(1) The amounts in this column represent approximately two months of base salary to reflect the commencement of each Named Executive Officer s employment with Roan LLC. Mr. Maranto s employment with Roan LLC commenced October 30, 2017; Mr. Condray s employment with Roan LLC commenced November 13, 2017; and Mr. Pettit s employment with Roan LLC commenced November 6, 2017.

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

(3) 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 Performance Stock Units which is included in this Current Report. Please see the section of the Compensation Discussion and Analysis above entitled Performance Share Unit Awards and the Grants of Plan-Based Awards Table below for additional information regarding these awards.

Grants of Plan-Based Awards

The table below includes information about PSU awards granted to our Named Executive Officers during the 2017 Fiscal Year under the Plan.

	Grant Date (1)	Board Approval	Estimated Future Payouts Under Equity	Grant Date Fair Value

Name		Date (1)	Incentive Plan Awards (2) Threshold (#)	Target (#)	Maximum (#)	of Unit Awards ($)(3)
Tony C. Maranto	12/12/2017	12/15/2017	1,875,000	7,500,000	15,000,000	$ 10,575,000
Greg T. Condray	12/12/2017	12/15/2017	550,000	2,200,000	4,400,000	$ 3,102,000
Joel L. Pettit	12/12/2017	12/15/2017	500,000	2,000,000	4,000,000	$ 2,820,000

(1) The PSU awards were granted on December 12, 2017 and ratified by the board of managers of Roan LLC on December 15, 2017.

(2) Amounts in these columns represent the number of PSU awards granted in 2017 that would vest upon the achievement of a threshold, target, and maximum level of performance. 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 value at such time.

(3) Amounts in this column represent the grant date fair value of PSU awards granted to our Named Executive Officers in 2017 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 Performance Stock Units which is included in this Current Report. Please see the section of the Compensation Discussion and Analysis above entitled Performance Share Unit Awards 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. 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, $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 Mr. Condray and 75% for Mr. Pettit. Mr. Condray s employment agreement also provided for a signing bonus of $250,000 in connection with the commencement of his employment, which is subject to repayment in the event he resigns or we terminate his employment for cause prior to the first anniversary of his employment commencement date. 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, 2017.

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	15,000,000	$ 22,800,000
Greg T. Condray	4,400,000	$ 6,688,000
Joel L. Pettit	4,000,000	$ 6,080,000

(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 Roan LLC through such date. The number of units reported in this column assumes that the value of Roan LLC for the performance period is achieved at the maximum 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 less.

(2) To the extent earned, each performance share unit subject to a PSU award represents the right to receive one Roan LLC unit 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 Common Stock.

(3) Amounts in this column reflect the market value of the Roan LLC units subject to the PSU awards, calculated by multiplying the number of units reported by $1.52 per Roan LLC unit, the fair market value of the Roan LLC units as of December 31, 2017.

Option Exercises and Stock Vested

No equity awards held by our Named Executive Officers vested during the 2017 Fiscal Year. We have not granted options pursuant to the Plan 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 the Summary Compensation Table and Grants of Plan-Based Awards Table, we have entered into employment agreements with each of our Named Executive Officers that provide for severance payments in certain circumstances. Upon a termination of a Named Executive Officer s employment by us without cause or upon a Named Executive Officer s resignation for good reason, each 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.

Under each Named Executive Officer s 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; 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 Performance Share Units shall become vested based the number of days which have elapsed and the achievement of the performance goals from the beginning of the performance period through the date of termination. If a termination described in the preceding sentence occurs 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 Performance Share Units will be settled in accordance with the performance 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 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.

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 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;

consummation of a business combination unless following such business combination (a) the outstanding 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 included as Exhibits 10.4, 10.5, 10.8, 10.9, 10.10, 10.11 and 10.12 attached hereto.

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 LLC had occurred on December 31, 2017, 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 LLC.

Executive	**Termination of Employment by Roan LLC Without Cause or by Executive for Good Reason ($)**	**Termination of Employment by Death or Disability ($)**	**Termination by Roan LLC Without Cause or 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**			
Greg T. Condray				
Cash Severance	$ 800,000		$ 800,000	
Accelerated Equity	(1)	(1)	(1)	
Total	**$ 800,000**			
Joel L. Pettit				
Cash Severance	$ 700,000		$ 700,000	
Accelerated Equity	(1)	(1)	(1)	
Total	**$ 700,000**			

(1) Because the performance period with respect to the PSU awards did not commence until January 1, 2018, a termination on December 31, 2017 would have resulted in a forfeiture of the full PSU award.

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

Director Compensation

Members of the board of managers of Roan LLC did not receive any compensation for their services as directors in 2017.

Equity Compensation Plan Information

The following table sets forth information about Roan LLC units that may be issued under equity compensation plans as of December 31, 2017. As described in the Compensation Discussion and Analysis Actions Taken Following Fiscal Year End, the Plan was amended, restated and renamed the Amended and Restated Plan, and the Roan LLC units available to be granted thereunder were converted to shares of Common Stock.

	(a) Number of securities to be issued upon exercise of outstanding options,	**(b) Weighted-average exercise price of outstanding options,**	**(c) Number of securities remaining available for future issuance under equity**

	warrants and rights (1)	warrants and rights (2)	compensation plans (excluding securities reflected in column (a)) (3)
Equity compensation plans approved by security holders		$	
Equity compensation plans not approved by security holders	34,100,000	$	70,900,000
Total	34,100,000	$	70,900,000

(1) This column reflects the maximum number of Roan LLC units subject to PSU awards granted under the Plan outstanding and unvested as of December 31, 2017. 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 Plan.

(2) No options or warrants have been granted under the Plan, 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 Roan LLC units remaining available for issuance under the Plan as of December 31, 2017.

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 with 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 six months ended June 30, 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.

Accounts receivable affiliates at June 30, 2018 of $31.7 million primarily related to the Company s share of revenue less direct operating expenses associated with production from oil and natural gas properties during the period Citizen and Old Linn served as operator.

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. At June 30, 2018, amounts due to Old Linn of $26.3 million were included in accounts payable and accrued liabilities affiliates in the accompanying balance sheets and reflect amounts owed to Old Linn for the working capital accounts acquired, partially offset by amounts due to the Company for revenue associated with production from oil and natural gas properties Old Linn operated on the Company s behalf.

Citizen Energy II, LLC

Atlas, LLC (Atlas) provides 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 their interest in a Jones Energy, LLC well in Canadian County, Oklahoma, and, in connection, Roan LLC paid Jones Energy, Inc. a total of $0.4 million. JVL, which employs certain of our directors and following the Reorganization indirectly owns 50.0% of our Common Stock, holds 17.6% of the combined voting power of Jones Energy, Inc. Messrs. Lovoi and Loyd are members of our Board and the board of directors of Jones Energy, Inc.

Riviera Resources, Inc.

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 are reflected as natural gas sales affiliates and natural gas liquids sales affiliates in the accompanying statements of operations. There were no such sales to Blue Mountain during the six months ended June 30, 2017.

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. As of 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.

Stockholders Agreement

The material provisions of the Stockholders Agreement are described under Item 1.01 which is incorporated in this Item 2.01 by reference.

Roan LLC Agreement

The material provisions of the Roan LLC Agreement are described under Item 1.01 which is incorporated in this Item 2.01 by reference**.**

Registration Rights Agreement

The material provisions of the Registration Rights Agreement are described under Item 1.01 which is incorporated in this Item 2.01 by reference**.**

Voting Agreement

The material provisions of the Voting Agreement are described under Item 1.01 which is incorporated in this Item 2.01 by reference.

Master Reorganization Agreement

As previously disclosed by New Linn, and as described under Introductory Note, on September 17, 2018, the Company entered into the Master Reorganization Agreement with New Linn and Roan Holdings, which set forth the terms of the Reorganization. The parties thereto consummated the Master Reorganization Agreement on the Effective

Date. The description of the Reorganization in Item 1.01 of this Current Report is incorporated in this Item 2.01 by reference.

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 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 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 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 adopted a written related party transactions policy. Pursuant to this policy, our audit committee will review all material facts of all future