SANDRIDGE ENERGY INC
Form 10-K
March 05, 2019
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2018

OR

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

For the transition period from to

Commission File Number: 001-33784

SANDRIDGE ENERGY, INC.

(Exact name of registrant as specified in its charter)

Delaware	**20-8084793**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

123 Robert S. Kerr Avenue Oklahoma City, Oklahoma	**73102**
(Address of principal executive offices)	**(Zip Code)**

(405) 429-5500

(Registrant's telephone number, including area code)

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

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

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

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No ¨

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes þ No ¨

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

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

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

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

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. o

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

The aggregate market value of our common stock held by non-affiliates on June 29, 2018 was approximately $539.2 million based on the closing price as quoted on the New York Stock Exchange. As of February 20, 2019, there were 35,687,601 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company's definitive proxy statement for the 2019 Annual Meeting of Stockholders, which will be filed with the SEC within 120 days of December 31, 2018, are incorporated by reference in Part III.

SANDRIDGE ENERGY, INC.
2018 ANNUAL REPORT ON FORM 10-K
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GLOSSARY OF TERMS

References in this report to the “Company,” “SandRidge,” “we,” “our,” and “us” mean SandRidge Energy, Inc., including its consolidated subsidiaries and variable interest entities of which it is the primary beneficiary. References to the “Successor” or the “Successor Company” relate to SandRidge subsequent to October 1, 2016. References to the “Predecessor” or “Predecessor Company” refer to SandRidge on and prior to October 1, 2016. In addition, the following is a description of the meanings of certain terms used in this report.

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

2009 Plan. SandRidge Energy, Inc. 2009 Incentive Plan.

ASC. Accounting Standards Codification.

ASU. Accounting Standards Update.

Bankruptcy Code. United States Bankruptcy Code.

Bankruptcy Court. United States Bankruptcy Court for the Southern District of Texas.

Bankruptcy Petitions. Voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to oil or other liquid hydrocarbons.
Bcf. Billion cubic feet of natural gas.
Bench. A geological horizon; a distinctive stratum useful for stratigraphic correlation.
Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil. Although an equivalent barrel of condensate or natural gas may be equivalent to a barrel of oil on an energy basis, it is not equivalent on a value basis as there may be a large difference in value between an equivalent barrel and a barrel of oil. For example, based on the commodity prices used to prepare the estimate of the Company’s reserves at year-end 2018 of $65.56/Bbl for oil and $3.10/Mcf for natural gas, the ratio of economic value of oil to natural gas was approximately 21 to 1, even though the ratio for determining energy equivalency is 6 to 1.
Boe/d. Boe per day.
Bonanza Creek. Bonanza Creek Energy, Inc.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Building Note. Note with a principal amount of $35.0 million, as amended in February 2017, which was secured by first priority mortgages on the Company’s real estate in Oklahoma City, Oklahoma.

Cash Collateral Account. Restricted cash account controlled by the administrative agent to the First Lien Exit Facility.

CBP. Central Basin Platform.

Ceiling limitation. Present value of future net revenues from proved oil, natural gas and NGL reserves, discounted at 10% per annum, plus the lower of cost or fair value of unproved properties, plus estimated salvage value, less related tax effects.

CO_2. Carbon dioxide.

Common Stock. Common stock in the Successor Company.
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Completion. The process of treating a drilled well, primarily through hydraulic fracturing, followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry well, the reporting to the appropriate authority that the well has been abandoned.
Convertible Notes. Non-interest bearing 0.00% convertible senior secured subordinated notes due 2020.
Convertible Senior Unsecured Notes. 8.125% Convertible Senior Notes due 2022 and 7.5% Convertible Senior Notes due 2023.

Counterparty. Counterparty to the Company's drilling participation agreement.

Credit facility. Senior credit facility dated February 10, 2017.

Debtors. The Company and certain of its direct and indirect subsidiaries which collectively filed for reorganization under the Bankruptcy Code on May 16, 2016.

Developed acreage. The number of acres that are assignable to productive wells.
Developed oil, natural gas and NGL reserves. Reserves of any category that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.
Development costs. Costs incurred to obtain access to proved reserves, complete wells and provide facilities for extracting, treating, gathering and storing the oil and natural gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to (i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building and relocating public roads, gas lines and power lines, to the extent necessary in developing the proved reserves, (ii) drill, equip and complete development wells, development-type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly, (iii) acquire, construct and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems, and (iv) provide improved recovery systems.
Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.
Dry well. An exploratory, development or extension well that proves to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Early settlements. Settlements of commodity derivative contracts prior to contractual maturity.

Emergence Date. Date the Debtors emerged from bankruptcy, October 4, 2016.

Exchange Act. Securities Exchange Act of 1934, as amended.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to produce oil or natural gas in another reservoir.
Extended-reach lateral ("XRL"). Extended-reach lateral wells are horizontal wells where the horizontal segment or lateral is at least approximately 9,000-9,500 feet in length and may extend further. When referencing lateral counts, XRL's are counted as more than one lateral depending on the relationship of length to an SRL length. E.g. a 9,000 foot lateral would be counted as two laterals.
FASB. Financial Accounting Standards Board.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geological barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “structural

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feature” and “stratigraphic condition” are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas of interest, etc.
First Lien Exit Facility. $425.0 million reserve-based revolving credit facility entered into on the Emergence Date.
Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.
Horizontal well. A well that is turned horizontally at depth, providing access to oil and gas reserves at a wide range of angles.
Hydraulic fracturing. Procedure to stimulate production by forcing a mixture of fluid and proppant into the formation under high pressure. Hydraulic fracturing creates artificial fractures in the reservoir rock to increase permeability and porosity.
IRS. Internal Revenue Service.
Lease. A contract in which the owner of minerals gives a company or working interest owner temporary and limited rights to explore for, develop, and produce minerals from the property, or; any transfer where the owner of a mineral interest assigns all or a part of the operating rights to another party but retains a continuing nonoperating interest in production from the property.
MBbls. Thousand barrels of oil or other liquid hydrocarbons.
MBoe. Thousand barrels of oil equivalent.
Mcf. Thousand cubic feet of natural gas.
MMBbls. Million barrels of oil or other liquid hydrocarbons.
MMBoe. Million barrels of oil equivalent.
MMBtu. Million British Thermal Units.
MMcf. Million cubic feet of natural gas.
MMcf/d. MMcf per day.
Mississippian Trust I. SandRidge Mississippian Trust I.

Mississippian Trust II. SandRidge Mississippian Trust II.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells, as the case may be.
Netherland Sewell. Netherland, Sewell & Associates, Inc.

NGL. Natural gas liquids, such as ethane, propane, butanes and natural gasoline that are extracted from natural gas production streams.

NYMEX. The New York Mercantile Exchange.

NYSE. New York Stock Exchange.

Occidental. Occidental Petroleum Corporation.

Omnibus Incentive Plan. SandRidge Energy, Inc. 2016 Omnibus Incentive Plan.

Permian Divestiture. The November 1, 2018 sale of substantially all of the Company's oil and natural gas properties, rights and related assets in the CBP region of the Permian Basin, along with 13,125,000 common units representing a 25% equity interest in the Permian Trust to an independent third party.

Permian Trust. SandRidge Permian Trust.

Plan. Debtors’ joint plan of reorganization, as amended.

Poison Pill. Agreement with American Stock Transfer & Trust Company, LLC on November 26, 2017, as amended by the First Amendment to the Stockholder Rights Agreement dated January 22, 2018.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

Predecessor 2016 Period. Period from January 1, 2016, through October 1, 2016.

Present value of future net revenues. The present value of estimated future revenues to be generated from the production of proved reserves, before income taxes, calculated in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation and without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization. PV-10 is calculated using an annual discount rate of 10% and PV-9 is calculated using an annual discount rate of 9%.

Production costs. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities that become part of the cost of oil and natural gas produced.

Productive well. A well that is found to be capable of producing oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Prospect. A specific geographic area that, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed reserves. Reserves that are both proved and developed.

Proved oil, natural gas and NGL reserves. Those quantities of oil, natural gas and NGLs which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. For additional information, see the SEC's definition in Rule 4-10(a) (22) of Regulation S-X, a link for which is available at the SEC's website.

Proved undeveloped reserves. Reserves that are both proved and undeveloped.

PV-9. See "Present value of future net revenues" above.

PV-10. See "Present value of future net revenues" above.

Reserves. Estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a certain date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market, and all permits and financing required to implement the project.

Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (*i.e.,* absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (*i.e.*, potentially recoverable resources from undiscovered accumulations).

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

Royalty Interest. An interest in an oil and natural gas property entitling the owner to a share of oil, natural gas or NGL production free of costs of production.

Royalty Trust. Individually, the SandRidge Mississippian Trust I, the SandRidge Mississippian Trust II and the SandRidge Permian Trust.

Royalty Trusts. Collectively, the SandRidge Mississippian Trust I, the SandRidge Mississippian Trust II and the SandRidge Permian Trust.

Ryder Scott. Ryder Scott Company, L.P.

SEC. Securities and Exchange Commission.

SEC prices. Unweighted arithmetic average oil and natural gas prices as of the first day of the month for the most recent 12 months as of the balance sheet date.

Securities Act. Securities Act of 1933, as amended.

Senior credit facility. Predecessor Company's pre-petition senior secured revolving credit facility.

Senior Secured Notes. Collectively, the 8.75% Senior Secured Notes due 2020 and the 8.75% Senior Secured Notes due 2020 issued to Piñon Gathering Company, LLC.

Senior Unsecured Notes. Collectively, the 8.75% Senior Notes due 2020, 7.5% Senior Notes due 2021, 8.125% Senior Notes due 2022 and 7.5% Senior Notes due 2023.

Standard-reach lateral ("SRL"). Standard-reach lateral wells are horizontal wells where the horizontal segment or lateral is approximately 4,000- 4,500 feet in length.

Standardized measure or standardized measure of discounted future net cash flows. The present value of estimated future cash inflows from proved oil, natural gas and NGL reserves, less future development and production costs and future income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes on future net revenues.

Successor 2016 Period. Period after October 1, 2016 through December 31, 2016.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or natural gas regardless of whether such acreage contains proved reserves.

Undeveloped oil, natural gas and NGL reserves. Reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion.

i.Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

ii.Undrilled locations are classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

iii.Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

Unsecured Notes. Collectively, the Convertible Senior Unsecured Notes and the Senior Unsecured Notes.

Warrants. Series A warrants and Series B warrants with initial exercise prices of $41.34 and $42.03 per share, respectively, which expire on October 4, 2022.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.
WTI. West Texas Intermediate.

WTO. West Texas Overthrust.

Cautionary Note Regarding Forward-Looking Statements

This report includes "forward-looking statements" as defined by the SEC. These forward-looking statements may include projections and estimates concerning our capital expenditures, liquidity, capital resources and debt profile, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, elements of our business strategy, compliance with governmental regulation of the oil and natural gas industry, including environmental regulations, acquisitions and divestitures and the potential effects on our financial condition and other statements concerning our operations, financial performance and financial condition. Forward-looking statements are generally accompanied by words such as “estimate,” “assume,” “target,” “project,” “predict,” “believe,” “expect,” “anticipate,” “potential,” “could,” “may,” “foresee,” “plan,” “goal,” “should,” “intend” or other words that convey the uncertainty of future outcomes. These forward-looking statements are based on certain assumptions and analyses based on our experience and perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Such statements are not guarantees of future performance and actual results or developments may differ materially from those projected. The Company disclaims any obligation to update or revise these forward-looking statements unless required by law, and cautions readers not to rely on them unduly. While we consider these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties relating to, among other matters, the risks and uncertainties discussed in “Risk Factors” in Item 1A of this report, as well as the following:
•risks associated with drilling oil and natural gas wells;
•the volatility of oil, natural gas and NGL prices;
•uncertainties in estimating oil, natural gas and NGL reserves;
•the need to replace the oil, natural gas and NGL reserves the Company produces;
•our ability to execute our growth strategy by drilling wells as planned;
•the amount, nature and timing of capital expenditures, including future development costs, required to develop our undeveloped areas;
•concentration of operations in the Mid-Continent region of the United States;
•limitations of seismic data;
•the potential adverse effect of commodity price declines on the carrying value of our oil and natural properties;
•severe or unseasonable weather that may adversely affect production;
•availability of satisfactory oil, natural gas and NGL marketing and transportation options;
•availability and terms of capital to fund capital expenditures;
•amount and timing of proceeds of asset monetizations;
•potential financial losses or earnings reductions from commodity derivatives;
•potential elimination or limitation of tax incentives;
•risks and uncertainties related to the adoption and implementation of regulations restricting oil and gas development in states where we operate;
•competition in the oil and natural gas industry;
•general economic conditions, either internationally or domestically affecting the areas where we operate;
•costs to comply with current and future governmental regulation of the oil and natural gas industry, including environmental, health and safety laws and regulations, and regulations with respect to hydraulic fracturing and the disposal of produced water;
•risks and uncertainties related to the potential sale or lease of our corporate headquarters; and

• the need to maintain adequate internal control over financial reporting.

PART I

Item 1. *Business*

GENERAL

We are an oil and natural gas company, organized in 2006 as a Delaware corporation, with a principal focus on exploration and production activities in the U.S. Mid-Continent and North Park Basin of Colorado.

As of December 31, 2018, we had an interest in 1,777 gross (1,095.8 net) producing wells, approximately 1,272 of which we operate, and approximately 777,000 gross (571,000 net) total acres under lease. As of December 31, 2018, we had two rigs drilling in the Mid-Continent and one rig drilling in the North Park Basin. Total estimated proved reserves as of December 31, 2018, were 160.2 MMBoe, of which approximately 58% were proved developed.

Our principal executive offices are located at 123 Robert S. Kerr Avenue, Oklahoma City, Oklahoma 73102 and our telephone number is (405) 429-5500. Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports are made available free of charge on our website at www.sandridgeenergy.com as soon as reasonably practicable after we file such material with, or furnish it to, the SEC. Any materials that we have filed with the SEC may be accessed via the SEC's website address at *www.sec.gov*.

Reorganization Under Chapter 11 and Emergence from Bankruptcy

On May 16, 2016, the Debtors filed Bankruptcy Petitions for reorganization under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court. The Bankruptcy Court confirmed the Plan, and the Debtors' subsequently emerged from bankruptcy on the Emergence Date. The Company's Chapter 11 reorganization and related matters are addressed in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations," "Note 1 - Voluntary Reorganization under Chapter 11 Proceedings" and "Note 2 - Summary of Significant Accounting Policies" to the accompanying consolidated financial statements contained in Item 8. "Financial Statements and Supplementary Data."

Fresh Start Accounting

Upon emergence from Chapter 11, we elected to apply fresh start accounting effective October 1, 2016, to coincide with the timing of our normal fourth quarter reporting period, which resulted in SandRidge becoming a new entity for financial reporting purposes. As a result of the application of fresh start accounting and the effects of the implementation of the Plan, the financial statements after October 1, 2016 are not comparable with the financial statements prior to that date. References to the "Successor" or the "Successor Company" relate to SandRidge subsequent to October 1, 2016. References to the "Predecessor" or "Predecessor Company" refer to SandRidge on and prior to October 1, 2016.

Our Mission

SandRidge Energy's mission is to *deliver a competitive and sustainable rate of return to its shareholders* by developing, acquiring, and exploring for oil and natural gas resources. The Company's asset portfolio is positioned to deliver long-term value to shareholders through its inventory of development opportunities in the NW STACK and Mississippian Lime Plays in Oklahoma and the Niobrara in North Park Basin, Colorado. We intend to acquire additional assets in the United States to lower the break-even costs of our investment portfolio and to ensure we deliver competitive and sustainable returns.

Our Business Strategy

SandRidge's business strategy is to acquire, explore for, and develop hydrocarbon resources in the United States; focus on financial discipline, flexibility, and value creation; and ensure health, safety, and environmental excellence while demonstrating the Company's core values. We will accomplish this strategy by focusing on the following key objectives:

Attract and retain the best people. Achieving our mission will only be possible through our employees. It is therefore critical to have compensation, development, and human resource programs that attract, retain and motivate the types of people we need to succeed.

Pursue operational excellence with a sense of urgency. We plan to deliver low cost, consistent and efficient execution of our drilling campaigns, work programs and operations. We will execute our operations in a safe and environmentally responsible manner, quickly and efficiently apply advanced technologies, and continuously seek ways to reduce our operating cash costs on a per barrel basis. Operational excellence is the foundation upon which we will achieve our mission.

Invest in high-margin, high rate-of-return projects. The key to achieving our mission will be to prioritize our work programs and allocate our capital to projects that deliver high returns. Additionally, we will assess the full range of uncertainty and thoroughly understand the risks associated with every oil and gas investment so we can accurately and consistently predict our results.

Continuously upgrade our investment portfolio to reduce break-even costs. We will actively pursue accretive acquisitions, mergers and dispositions to improve our margins and returns and to reduce the break-even costs of our portfolio of investment opportunities. This component of our strategy is key to delivering competitive returns to our shareholders on a sustainable basis.

Protect our balance sheet and demonstrate financial discipline. Having the ability to capitalize on opportunities when they arise and investing to generate competitive and sustainable returns requires the financial flexibility that can only be achieved through the financial discipline of balancing our growth plans with the preservation of our balance sheet. To accomplish this we will adhere to the financial principles that lead to the responsible use of leverage, hedging strategies that are complementary to our use of debt and help ensure the necessary cash flow to sustain our capital programs, and financial strategies that focus on delivering competitive debt-adjusted per share returns.

Acquisitions and Divestitures of Oil and Gas Properties

2018 Divestiture and Acquisition

Divestiture of Permian Basin Properties. On November 1, 2018, we sold substantially all of our oil and natural gas properties, rights and related assets in the CBP region of the Permian Basin, primarily located in Andrews County, TX, along with all of our 13,125,000 common units representing a 25% equity interest in the Permian Trust, to an independent third party for $14.5 million in cash, subject to certain remaining post-closing adjustments, and reduced our asset retirement obligations by approximately $26.9 million. The CBP assets and interest in the Permian Trust include 1,066 producing wells within the Permian Trust's area of mutual interest, certain wells not associated with the Permian Trust, a field office, and all equipment, inventory and yards associated with the Company's CBP operations. As a result of this divestiture, we will no longer have any obligations associated with the Permian Trust. This transaction did not result in a significant alteration of the relationship between our capitalized costs and proved reserves and, accordingly, the divestiture was accounted for as an adjustment to the full cost pool with no gain or loss recognized on the sale.

Acquisition of Oil and Natural Gas Interests. On November 2, 2018, the Company acquired an interest in certain oil and natural gas properties, rights and related assets in the Mississippian Lime and NW STACK areas of Oklahoma and Kansas for approximately $22.5 million in net consideration, net of post-closing adjustments, and assumed asset retirement obligations of approximately $6.4 million. The acquired assets primarily consist of interests in 1,199 producing wells, approximately 80% of which are operated by the Company, an additional 11.1% working interest in approximately 397,000 gross (44,000 net) acres across the Mid-Continent, and an additional 13.2% working interest ownership in the Company's saltwater gathering and disposal system in the Mississippian Lime. This acquisition is expected to increase total production for existing producing properties by approximately 10%.

2017 Acquisition and Divestitures

NW STACK. On February 10, 2017, the Company acquired assets consisting of approximately 13,000 net acres in Woodward County, Oklahoma for approximately $47.8 million in cash, net of post-closing adjustments. Also included in the acquisition were working interests in four wells previously drilled on the acreage.

Oil and Natural Gas Property Divestitures. In 2017, the Company divested various non-core oil and natural gas properties for approximately $17.1 million in cash. All of these divestitures were accounted for as adjustments to the full cost pool with no gain or loss recognized.

2016 Divestiture and Release from Treating Agreement

In January 2016, we transferred ownership of substantially all of our oil and natural gas properties and midstream assets located in the Piñon field in the WTO and $11.0 million in cash to a wholly owned subsidiary of Occidental and were released from all past, current and future claims and obligations under an existing 30-year treating agreement with Occidental.

In connection with this transfer, the Predecessor Company recognized a loss of approximately $89.1 million upon termination of the treating agreement and the cease-use of transportation agreements that supported production from the Piñon field and reduced asset retirement obligations associated with these oil and natural gas properties by $34.1 million.

PRIMARY BUSINESS OPERATIONS

Our primary operations are the exploration, development and production of oil and natural gas. The following table presents information concerning our exploration and production activities by geographic area of operation as of December 31, 2018.

Area	Estimated Net Proved Reserves (MMBoe)	Daily Production (MBoe/d)(1)	Reserves/ Production (Years)(2)	Gross Acreage	Net Acreage	Capital Expenditures (In millions) (3)	
Mid-Continent	110.9	29.9	10.2	643,015	445,189	$	58.4
North Park Basin	49.3	3.8	35.5	123,135	116,973	109.4	
Other	—	—	—	10,969	8,575	2.5	
Total	160.2	33.7	13.0	777,119	570,737	$	170.3

1.Average daily net production for the month of December 2018.
2.Estimated net proved reserves as of December 31, 2018 divided by production for the month of December 2018, annualized.
3.Capital expenditures for the year ended December 31, 2018, on an accrual basis.

Properties

Mid-Continent

We held interests in approximately 643,000 gross (445,000 net) leasehold acres located primarily in Oklahoma and Kansas at December 31, 2018. Associated proved reserves at December 31, 2018 totaled 110.9 MMBoe, 77.6% of which were proved developed reserves. Our interests in the Mid-Continent as of December 31, 2018 included 1,739 gross (1,057.8 net) producing wells with an average working interest of 61%. We had two rigs operating in the Mid-Continent as of December 31, 2018, which were drilling horizontal wells. One of the rigs was drilling under the drilling participation agreement described below. At December 31, 2018, our Mid-Continent properties included an inventory of 90 operated proved undeveloped laterals. Additionally, we estimate there are several hundred undeveloped probable horizontal well locations. During 2018, we completed a total of 21 horizontal producing wells in this area, which consisted primarily of SRLs.

NW STACK. The Meramec and Osage formations are the primary targets in the STACK play of Blaine and Kingfisher Counties, and are currently being drilled using horizontal well technology in a play area called the NW STACK in Garfield, Major, Dewey, and Woodward Counties. These formations are Mississippian in age, lying above the Woodford Shale formation and below Chester (if present) and Pennsylvanian formations. The Meramec is composed of interbedded shales, sands, and carbonates while the Osage is composed of low porosity, fractured limestone and chert. The top of these target formations ranges in depth from about 5,800 feet at the northern edge of the basin to greater than 14,000 feet toward the interior of the basin. Meramec formation thickness ranges from about 50 feet to over 400 feet and the Osage formation thickness ranges from about 450 to 1,400 feet. The Woodford Shale is the primary hydrocarbon source for both the Meramec and Osage, although the organic content in the Meramec Shale may provide a self-sourcing component as well. Similar to the STACK, there is an over-pressured area and normally pressured area in the NW STACK. Significant industry activity in the NW STACK has established both the Meramec and Osage as productive reservoirs with successful wells. We completed 17 wells in the Meramec formation during 2018 and no Osage wells. Of our total Mid-Continent acreage at December 31, 2018, approximately 116,000 gross (65,000 net) acres are associated with the NW STACK play area.

In the third quarter of 2017, we entered into a $200.0 million drilling participation agreement with a Counterparty to jointly develop new horizontal wells on a wellbore only basis within certain dedicated sections of our undeveloped leasehold acreage within the Meramec formation in the NW STACK. Under this agreement, the Counterparty is paying 90% of the net drilling and completion costs, up to $100.0 million in the first tranche, in exchange for an initial 80% net working interest in each new well, subject to certain reversionary hurdles. As a result, we are receiving a 20% net working interest after funding 10% of the drilling and completion costs related to the subject wells. We operate all of the wells developed under this agreement and retain sole discretion as to the number, location and schedule of wells drilled. The Counterparty also has the option to fund a second $100.0 million tranche, subject to mutual agreement. See "Operational Activities" included in Item 7 of this report for further discussion of the drilling participation agreement.

Mississippian Lime Formation. The Mississippian Lime formation is an expansive carbonate hydrocarbon system located on the Anadarko Shelf in northern Oklahoma and southern Kansas, and is a target for exploration and development within the Mid-Continent. The top of this formation is encountered between approximately 4,000 and 7,000 feet and stratigraphically between various formations of Pennsylvanian age and the Devonian-aged Woodford Shale formation. The Mississippian formation is approximately 350 to 650 feet in gross thickness across our lease position and has targeted porosity zone(s) ranging between 20 and 150 feet in thickness. At December 31, 2018, we had approximately 527,000 gross (381,000 net) acres under lease and 1,289 gross (864.8 net) producing wells in the Mississippian formation. We completed two horizontal wells, including one XRL and one SRL, in the Mississippian Lime formation in 2018.

North Park Basin

Our North Park Basin properties consisted of approximately 123,000 gross (117,000 net) acres, and 38 gross and net producing wells with a working interest of 100%, at December 31, 2018. Associated proved reserves at December 31, 2018 totaled approximately 49.3 MMBoe, of which 12.7% were proved developed reserves. The North Park Basin acreage is located in north central Colorado and, similar to the DJ Basin next to Colorado's Front Range, has multiple potential pay targets in addition to the Niobrara Shale play where our activity is currently focused. Although untested, zones shallower and deeper than the Niobrara have indications of potentially commercial hydrocarbons. The Niobrara Shale is characterized by stacked pay benches at depths of 5,500 to 9,000 feet with overall reservoir thickness over 450 feet. Based on our delineation drilling on acreage inside and outside federal units, we are developing a proved area where we have 193 proved undeveloped lateral locations. Across our entire acreage position, we estimate there are approximately 1,000 undeveloped probable horizontal lateral locations. We had one rig operating in the North Park Basin which was drilling a horizontal well as of December 31, 2018. We completed a total of eight horizontal producing wells, including seven XRLs and one SRL, in this area during 2018.

Proved Reserves

The portion of a reservoir considered to contain proved reserves includes (i) the portion identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil, natural gas or NGLs on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty.

Existing economic conditions include prices, costs, operating methods and government regulations existing at the time the reserve estimates are made. SEC prices are used to determine proved reserves, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. See further discussion of prices in "Risk Factors" included in Item 1A of this report.

Preparation of Reserves Estimates

Over 90% of the proved oil, natural gas and NGL reserves disclosed in this report are based on reserve estimates determined and prepared by independent reserve engineers primarily using decline curve analysis to determine the reserves of individual producing wells. A small portion of the proved reserves disclosed in this report were determined by internal reserve engineers. To establish reasonable certainty with respect to our estimated proved reserves, the independent and internal reserve engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using volumetric estimates or performance from analogous wells in the surrounding area. These wells were considered to be analogous based on production performance from the same formation and completions using similar techniques. The technologies and economic data used to estimate our proved reserves include, but are not limited to, well logs, geological maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. This data was reviewed by various levels of management for accuracy before consultation with independent reserve engineers. This consultation included review of properties, assumptions and data available. Internal reserve estimates were compared to those prepared by independent reserve engineers to test the estimates and conclusions before the reserves were included in this report. The accuracy of the reserve estimates is dependent on many factors, including the following:

•the quality and quantity of available data and the engineering and geological interpretation of that data;
•estimates regarding the amount and timing of future costs, which could vary considerably from actual costs;
•the accuracy of economic assumptions; and
•the judgment of the personnel preparing the estimates.

SandRidge’s Senior Vice President—Reserves, Technology and Business Development is the technical professional primarily responsible for overseeing the preparation of our reserves estimates. He has a Bachelor of Science degree in Petroleum Engineering with over 30 years of practical industry experience, including over 30 years of estimating and evaluating reserve information. He has also been a certified professional engineer in the state of Oklahoma since 2007 and a member of the Society of Petroleum Engineers since 1980.

SandRidge’s reserve engineers monitor well performance and make reserve estimate adjustments as necessary to ensure the most current information is reflected. The information used to prepare reserve estimates includes production histories as well as other geologic, economic, ownership and engineering data. The Corporate Reserves department currently has a total of six full-time employees, comprised of four degreed engineers and two engineering and business analysts with a minimum of a four-year degree in mathematics, finance or other business or science field.

We encourage ongoing professional education for our engineers and analysts on new technologies and industry advancements as well as refresher training on basic skill sets.

In order to ensure the reliability of reserves estimates, the Corporate Reserves department follows comprehensive SEC-compliant internal controls and policies to determine, estimate and report proved reserves including:
•confirming that we include reserves estimates for all properties owned and that they are based upon proper working and net revenue interests;
•ensuring the information provided by other departments within the Company such as Accounting is accurate;
•communicating, collaborating, and analyzing with technical personnel in our business units;
•comparing and reconciling the internally generated reserves estimates to those prepared by third parties;
•utilizing experienced reservoir engineers or those under their direct supervision to prepare reserve estimates; and
•ensuring compensation for the reserve engineers is not tied to the amount of reserves recorded.

Each quarter, the Senior Vice President—Reserves, Technology and Business Development presents the status of the Company’s reserves to senior executives, and subsequently obtains approval of significant changes from key executives. Additionally, the five year PUD development plan is reviewed and approved annually by the Company’s Chief Executive Officer, Chief Financial Officer, Chief Operating Officer, and the Senior Vice President - Reserves, Technology and Business Development.

The Corporate Reserves department works closely with independent petroleum consultants at each fiscal year end to ensure the integrity, accuracy and timeliness of annual independent reserves estimates. These independently developed reserves estimates are presented to the Audit Committee. In addition to reviewing the independently developed reserve reports, the Audit Committee also periodically meets with the independent petroleum consultants that prepare estimates of proved reserves.

The percentage of total proved reserves prepared by each of the independent petroleum consultants is shown in the table below.

	December 31,		
	2018	2017	2016
Cawley, Gillespie & Associates,	51.6%	62.6%	72.0%

Inc.			
Ryder Scott Company, L.P.	43.5%	29.0%	18.4%
Netherland, Sewell & Associates, Inc.	—%	3.8%	3.6%
Total	95.1%	95.4%	94.0%

The remaining 4.9%, 4.6% and 6.0% of estimated proved reserves as of December 31, 2018, 2017 and 2016, respectively, were based on internally prepared estimates, primarily for the Mid-Continent area.

Copies of the reports issued by our independent reserve consultants with respect to our oil, natural gas and NGL reserves for over 90% of all geographic locations as of December 31, 2018 are filed with this report as Exhibits 99.1 and 99.2. The geographic location of our estimated proved reserves prepared by each of the independent reserve consultants as of December 31, 2018 is presented below.

	Geographic Locations—by Area by State
Cawley, Gillespie & Associates, Inc.	Mid-Continent—KS, OK
Ryder Scott Company, L.P.	North Park Basin—CO, Mid-Continent—OK

The qualifications of the technical personnel at each of these firms primarily responsible for overseeing the firm's preparation of the Company's reserves estimates included in this report are set forth below. These qualifications meet or exceed the Society of Petroleum Engineers' standard requirements to be a professionally qualified Reserve Estimator and Auditor.

Cawley, Gillespie & Associates, Inc.
•more than 25 years of practical experience in the estimation and evaluation of petroleum reserves;
•a registered professional engineer in the state of Texas; and
•Bachelor of Science Degree in Petroleum Engineering.

Ryder Scott Company, L.P.
•more than 30 years of practical experience in the estimation and evaluation of petroleum reserves;
•a registered professional engineer in the states of Alaska, Colorado, Texas and Wyoming; and
•Bachelor of Science Degree in Petroleum Engineering and MBA in Finance;

Netherland, Sewell & Associates, Inc.
•practicing consultant in petroleum engineering since 2013 and over 14 years of prior industry experience;
•licensed professional engineers in the state of Texas; and
•Bachelor of Science Degree in Chemical Engineering

Reporting of Natural Gas Liquids

NGLs are recovered through further processing of a portion of our natural gas production stream. At December 31, 2018, NGLs comprised approximately 18% of total proved reserves on a barrel equivalent basis and represented volumes to be produced from properties where we have contracts in place for the extraction and sale of NGLs. NGLs are products sold by the gallon. In reporting proved reserves and production of NGLs, we have included production and reserves in barrels based on a conversion rate of 42 gallons per barrel. The extraction of NGLs in the processing of natural gas reduces the volume of natural gas available for sale. All production information related to natural gas is reported net of the effect of any reduction in natural gas volumes resulting from the processing and extraction of NGLs.

Reserve Quantities, PV-10 and Standardized Measure

The following estimates of proved oil, natural gas and NGL reserves are based on reserve reports as of December 31, 2018, 2017 and 2016, over 90% of which were prepared by independent reserve engineers. The reserve reports were based on our drilling schedule at the time year-end reserve estimates were prepared. Our year-end 2018 PUD development plan established that 100% of our current proved undeveloped reserves will be developed within five years from when they were originally recorded. See "Critical Accounting Policies and Estimates" in Item 7 of this report for further discussion of uncertainties inherent to the reserves estimates.

	December 31,		
	2018	2017	2016
Estimated Proved Reserves(1)			
Developed			
Oil (MMBbls)	18.7	25.9	25.9
NGL (MMBbls)	22.3	29.9	29.3
Natural gas (Bcf)	307.9	408.0	393.0
Total proved developed (MMBoe)	92.3	123.8	120.7
Undeveloped			
Oil (MMBbls)	45.3	35.9	27.0
NGL (MMBbls)	5.9	4.4	4.2
Natural gas (Bcf)	100.0	80.9	71.8
Total proved undeveloped (MMBoe)	67.9	53.8	43.2
Total Proved			
Oil (MMBbls)	64.0	61.8	52.9
NGL (MMBbls)	28.2	34.3	33.5
Natural gas (Bcf)	407.9	488.9	464.8
Total proved (MMBoe)	160.2	177.6	163.9
Standardized Measure of Discounted Net Cash Flows (in millions)(2)	$ 1,045.6	$ 749.3	$ 438.4

PV-10 (in millions)(3)	$	1,045.6	$	749.3	$	438.4

1. Estimated proved reserves, PV-10 and Standardized Measure were determined using SEC prices, and do not reflect actual prices received or current market prices. All prices are held constant throughout the lives of the properties. The index prices and the equivalent weighted average wellhead prices used in the reserve reports are shown in the table below.

	Index prices (a)						Weighted average wellhead prices (b)			
	Oil (per Bbl)		Natural gas (per Mcf)		Oil (per Bbl)		NGL (per Bbl)		Natural gas (per Mcf)	
December 31, 2018	$	65.56	$	3.10	$	60.86	$	25.62	$	1.77
December 31, 2017	$	51.34	$	2.98	$	48.47	$	20.28	$	1.90
December 31, 2016	$	42.75	$	2.48	$	38.59	$	10.99	$	1.56

a.Index prices are based on average West Texas Intermediate (“WTI”) Cushing spot prices for oil and average Henry Hub spot market prices for natural gas.
b.Average adjusted volume-weighted wellhead product prices reflect adjustments for transportation, quality, gravity, and regional price differentials.

2. Standardized Measure differs from PV-10 as standardized measure includes the effect of future income taxes. At December 31, 2018, 2017 and 2016, the difference between the standardized measure and PV-10 was insignificant due to an excess of tax basis in oil and natural gas properties over projected undiscounted future cash flows from our proved reserves.

3. PV-10 is a non-GAAP financial measure. Neither PV-10 nor Standardized Measure represents an estimate of fair market value of our oil and natural gas properties. PV-10 is used by the industry and by management as a reserve asset value measure to compare against past reserve bases and the reserve bases of other business entities. It is useful because its calculation is not dependent on the taxpaying status of the entity. The following table provides a reconciliation of our Standardized Measure to PV-10:

	December 31, 2018		2017		2016	
	(In millions)					
Standardized Measure of Discounted Net Cash Flows	$	1,045.6	$	749.3	$	438.4
Present value of future income tax discounted at 10%	—		—		—	
PV-10	$	1,045.6	$	749.3	$	438.4

Proved Reserves - Mid-Continent. Proved reserves in the Mid-Continent, primarily the Mississippian formation, decreased from 130.6 MMBoe at December 31, 2017 to 110.9 MMBoe at December 31, 2018. This reserve reduction is due primarily to downward revisions of 22.5 MMBoe of late life reserves due to (i) an increase in estimated future workover and improved recovery costs that shortened the economic lives of these properties, and (ii) 10.2 MMBoe of negative revisions to prior estimates stemming from changes in well performance, and 2018 production totaling 11.0 MMBoe. Additional reserve decreases amounting to 6.2 MMBoe were the result of wells being shut-in during 2018, changes to lease operating costs and other reserve parameters. Partially offsetting these reductions were the acquisition of 15.4 MMBoe in reserves, 10.3 MMBoe of reserve extensions and discoveries, largely associated with successful drilling in our NW STACK play and a 4.6 MMBoe increase associated with the increase in year-end SEC commodity pricing.

Proved Reserves - North Park Basin. Our North Park Basin proved reserves in the Niobrara increased from 40.2 MMBoe at December 31, 2017 to 49.3 MMBoe at December 31, 2018. This increase is due to the results of our development drilling program which resulted in 9.0 MMBoe of reserve extensions and discoveries associated with proved undeveloped reserves at an increased well density, 4.5 MMBoe in upward revisions primarily due to converting undeveloped well locations from SRLs to planned XRLs, and a 1.1 MMBoe increase associated with the increase in year-end SEC commodity pricing. These increases were partially offset by downward revisions of 3.7 MMBoe due to an increase in anticipated future lease operating expenses and project schedule changes that lowered estimated ultimate recoveries from these properties, 2018 production of 1.0 MMBoe, and other reductions amounting to 0.8 MMBoe. Our Niobrara proved developed reserves are attributed to 38 horizontal producing wells. Reservoir characteristics of the Niobrara in the North Park Basin are similar to those of the Niobrara in the DJ Basin, consisting of multiple stratigraphic benches. In the North Park Basin, production performance and reservoir data gathered from Niobrara producing wells confirm consistency in reservoir properties such as porosity, thickness and stratigraphic conformity. Using the performance of the proved developed producing wells, proved undeveloped reserves were recorded for 29 sections of the 35 section proved development area at a well density of eight wells per section and 12 wells per section for the remaining six sections. Delineation drilling to determine optimal well spacing is ongoing, although early results indicate the potential for booking more than eight wells per section.

Proved Undeveloped Reserves. The following table summarizes activity associated with proved undeveloped reserves during the periods presented:

	Year Ended December 31,		
	2018	2017	2016
Reserves converted from proved undeveloped to proved developed (MMBoe)	4.2	1.1	6.8
Drilling capital expended to convert proved undeveloped reserves to proved developed reserves (in millions)	$ 63.2	$ 21.0	$ 64.5

Total estimated proved undeveloped reserves were 67.9 MMBoe at December 31, 2018, which is an increase of 14.1 MMBoe from the prior year. This increase is primarily due to 18.0 MMBoe from extensions and discoveries which consisted primarily of 8.5 MMBoe in the North Park Basin from increased well density and successful development drilling in the Niobrara shale, and 9.5 MMBoe in the Mid-Continent from horizontal drilling in our NW STACK play. These extensions were offset by 4.2 MMBoe of PUD conversions.

Total estimated proved undeveloped reserves as of December 31, 2017 were 53.8 MMBoe, an increase of 10.6 MMBoe from the prior year. Reserves added from extensions and discoveries totaled 14.7 MMBoe, which consisted of 10.1 MMBoe in North Park from horizontal wells drilled in the Niobrara Shale, and 4.6 MMBoe in the Mid-Continent from horizontal drilling in our NW STACK play. These extensions were offset by 137 MBoe of proved undeveloped reserves at

December 31, 2016 that were converted to proved developed reserves during 2017, and net downward revisions of 4.0 MMBoe primarily due to removing PUDs attributable to expiring Mid-Continent undeveloped acreage outside of our NW STACK play that was not scheduled to be developed prior to lease expiry. Approximately 1.0 MMBoe of proved undeveloped reserves were booked and converted during the year 2017.

Total estimated proved undeveloped reserves were 43.2 MMBoe at December 31, 2016, which is a decrease of 20.9 MMBoe from the prior year, primarily due to downward revisions associated with lower prices that negatively impact economic viability of certain wells and recovery of estimated reserves. Reserves added from extensions and discoveries totaled 5.5 MMBoe, 3.2 MMBoe in the Mid-Continent as a result of horizontal drilling and 2.3 MMBoe in the North Park Basin from horizontal wells drilled in the Niobrara Shale. These extensions were offset by 5.2 MMBoe of proved undeveloped reserves at December 31, 2015 that were converted to proved developed reserves during 2016. Approximately 1.6 MMBoe of proved undeveloped reserves were booked and converted during the year 2016.

For additional information regarding changes in proved reserves during each of the three years ended December 31, 2018, 2017 and 2016 see “Note 22—Supplemental Information on Oil and Natural Gas Producing Activities” to the consolidated financial statements in Item 8 of this report.

Significant Fields

Oil, natural gas and NGL production for fields containing more than 15% of our total proved reserves at each year end are presented in the table below. The Mississippian Lime Horizontal field and the Niobrara field each contained more than 15% of total proved reserves at December 31, 2018, 2017 and 2016.

	Oil (MBbls)	**NGL (MBbls)**	**Natural Gas (MMcf)**	**Total (MBoe)**
Year Ended December 31, 2018				
Mississippian Lime Horizontal	1,558	2,477	31,663	9,312
Niobrara	1,034	—	—	1,034
Year Ended December 31, 2017				
Mississippian Lime Horizontal	2,382	2,995	38,834	11,849
Niobrara	673	—	—	673
Year Ended December 31, 2016				
Mississippian Lime Horizontal	5,029	4,357	56,894	18,868
Niobrara	500	—	—	500

Mississippian Lime Horizontal Field. The Mississippian Lime Horizontal Field is located on the Anadarko Shelf in northern Oklahoma and Kansas and produces from the Mississippian formation. Our interests in the Mississippian Lime Horizontal Field as of December 31, 2018 included 1,289 gross (864.8 net) producing wells and a 67% average working interest in the producing area.

Niobrara Field. The Niobrara field is located in Colorado and produces from the Niobrara Shale. Currently only oil is marketed while evaluation of midstream options for gas processing and marketing is ongoing. Field testing of gas processing techniques to extract liquids and convert gas to liquids is underway. Our interests in the Niobrara Field as of December 31, 2018, included 38 gross and net producing wells with a 100% average working interest in the producing area.

Production and Price History

The following table includes information regarding our net oil, natural gas and NGL production and certain price and cost information for each of the periods indicated.

	Successor			Predecessor
	Year Ended December 31, 2018	Year Ended December 31, 2017	Period from October 2, 2016 through December 31, 2016	Period from January 1, 2016 through October 1, 2016
Production data (in thousands)				
Oil (MBbls)	3,477	4,157	1,214	4,315
NGL (MBbls)	2,829	3,376	999	3,358
Natural gas (MMcf)	36,175	44,237	12,771	44,124
Total volumes (MBoe)	12,335	14,906	4,342	15,027
Average daily total volumes (MBoe/d)	33.8	40.8	47.7	54.6
Average prices—as reported(1)				
Oil (per Bbl)	$ 61.73	$ 48.72	$ 47.03	$ 36.85
NGL (per Bbl)	$ 23.72	$ 18.16	$ 14.77	$ 12.67
Natural gas (per Mcf)	$ 1.85	$ 2.09	$ 2.07	$ 1.78
Total (per Boe)	$ 28.27	$ 23.90	$ 22.64	$ 18.63
Expenses per Boe				
Production costs(2)	$ 7.12	$ 6.64	$ 5.69	$ 8.49

1.Prices represent actual average prices for the periods presented and do not include effects of derivative transactions.
2.Represents production costs per Boe excluding production and ad valorem taxes.

Productive Wells

The following table presents the number of productive wells in which we owned a working interest at December 31, 2018. We operate substantially all of our wells. Productive wells consist of producing wells and wells capable of producing, including oil wells awaiting connection to production facilities and natural gas wells awaiting pipeline connections to commence deliveries. Gross wells are the total number of producing wells in which we have a working interest and net wells are the sum of the fractional working interests owned in gross wells.

	Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Area						
Mid-Continent	1,482	936.3	257	121.5	1,739	1,057.8
North Park Basin	38	38.0	—	—	38	38.0
Total	1,520	974.3	257	121.5	1,777	1,095.8

Drilling Activity

The following table presents information with respect to wells completed during the periods indicated. This information is not necessarily indicative of future performance, and should not be interpreted to present any correlation between the number of productive wells drilled and quantities or economic value of reserves found. Productive wells are those that produce commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return. As of December 31, 2018, we had 11 gross (9.3 net) operated wells drilling, completing or awaiting completion.

	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Completed Wells						
Development						
Productive	29	15.5	22	16.4	32	27.0
Dry	—	—	—	—	—	—
Total	29	15.5	22	16.4	32	27.0
Exploratory						
Productive	—	—	1	1.0	—	—
Dry	—	—	—	—	—	—
Total	—	—	1	1.0	—	—
Total						
Productive	29	15.5	23	17.4	32	27.0
Dry	—	—	—	—	—	—
Total	29	15.5	23	17.4	32	27.0

We had two third-party rigs operating on our Mid-Continent acreage, and one rig operating on our North Park Basin acreage at December 31, 2018.

Developed and Undeveloped Acreage

The following table presents information regarding our developed and undeveloped acreage at December 31, 2018:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Area				
Mid-Continent	529,517	386,027	113,498	59,162
North Park Basin	13,652	13,647	109,483	103,326
Other	1,443	391	9,526	8,184
Total	544,612	400,065	232,507	170,672

Many of the leases included in the undeveloped acreage above will expire at the end of their respective primary terms. To prevent expiration, we may exercise our contractual rights to pay delay rentals to extend the terms of leases we value, or establish production from the leasehold acreage prior to expiration, which will keep the lease from expiring until production has ceased.

As of December 31, 2018, the gross and net acres subject to leases in the undeveloped acreage above are set to expire as follows:

	Acres Expiring	
	Gross	Net
Twelve Months Ending		
December 31, 2019	41,900	29,938
December 31, 2020	25,744	14,143
December 31, 2021	4,735	3,352
December 31, 2022 and later	3,678	1,886
Other(1)	156,450	121,353
Total	232,507	170,672

1.Leases remaining in effect until development efforts or production on the developed portion of the particular lease has ceased.

The acreage due to expire during the twelve months ending December 31, 2019, includes approximately 24,629 gross (15,163 net) acres in the Mid-Continent and 9,949 gross (7,453 net) acres in the North Park Basin.

Marketing and Customers

We sell our oil, natural gas and NGLs to a variety of customers, including utilities, oil and natural gas companies and trading and energy marketing companies. We had three customers that individually accounted for more than 10% of our total revenue during the 2018 period. See “Note 2—Summary of Significant Accounting Policies” to the consolidated financial statements in Item 8 of this report for additional information on our major customers. The number of readily available purchasers in the areas where we sell our production makes it unlikely that the loss of a single customer would materially affect our sales. We do not have any material commitments to deliver fixed and determinable quantities of oil and natural gas in the future under existing sales contracts or sales agreements.

Title to Properties

As is customary in the oil and natural gas industry, we conduct a preliminary review of the title to our properties. Prior to commencing drilling operations on our properties, we conduct a thorough title examination and perform curative work with respect to significant defects typically at our expense. In addition, prior to completing an acquisition of producing oil and natural gas assets, we perform title reviews on the most significant leases and depending on the materiality of properties, may obtain a drilling title opinion or review previously obtained title opinions. To date, we have obtained drilling title opinions on substantially all of our producing properties and believe that we have good and defensible title to our producing properties. Our oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens, which we believe does not materially interfere with the use of, or affect the carrying value of the properties.

COMPETITION

We compete with major oil and natural gas companies and independent oil and natural gas companies for leases, equipment, personnel and markets for the sale of oil, natural gas and NGLs. We believe our leasehold acreage position, geographic concentration of operations and technical and operational capabilities enable us to compete effectively with other exploration and production operations. However, the oil and natural gas industry is intensely competitive. See “Item 1A. Risk Factors” for additional discussion of competition in the oil and natural gas industry.

Oil, natural gas and NGLs compete with other forms of energy available to customers, including alternate forms of energy such as electricity, coal and fuel oils. Changes in the availability or price of oil, natural gas and NGLs or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil, natural gas and NGLs.

SEASONAL NATURE OF BUSINESS

Generally, demand for natural gas decreases during the summer months and increases during the winter months and demand for oil peaks during the summer months. Certain natural gas purchasers utilize natural gas storage facilities and acquire some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other oil and natural gas operations in a portion of our operating areas. These seasonal anomalies can pose challenges for meeting our well drilling objectives, delay the installation of production facilities, and increase competition for equipment, supplies and personnel during certain times of the year, which could lead to shortages and increase costs or delay operations.

ENVIRONMENTAL REGULATIONS

General

Our oil and natural gas exploration, development and production operations are subject to stringent and complex federal, state, tribal, regional and local laws and regulations governing worker safety and health, the discharge and disposal of substances into the environment, and the protection of the environment and natural resources. Numerous governmental entities, including the EPA and analogous state and local agencies, (and, under certain laws, private individuals) have the power to enforce compliance with these laws and regulations and any permits issued under them. These laws and regulations may, among other things: (i) require permits to conduct exploration, drilling, water withdrawal, wastewater disposal and other production related activities; (ii) govern the types, quantities and concentrations of substances that may be disposed or released into the environment or injected into formations in connection with drilling or production activities, and the manner of any such disposal, release, or injection; (iii) limit or prohibit construction or drilling activities or require formal mitigation measures in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered or threatened species; (iv) require investigatory and remedial actions to mitigate pollution conditions arising from the Company’s operations or attributable to former operations; (v) impose safety and health restrictions designed to protect employees from exposure to hazardous or dangerous substances; and (vi) impose obligations to reclaim and abandon well sites and pits. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties, the imposition of investigatory, remedial or corrective action obligations, the occurrence of delays or restrictions in permitting or performance of projects and the issuance of orders enjoining operations in affected areas.

The trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment. Any changes in or more stringent enforcement of these laws and regulations that result in delays or restrictions in permitting or development of projects or more stringent or costly construction, drilling, water management or completion activities or waste handling, storage, transport, remediation, or disposal emission or discharge requirements could have a material adverse effect on the Company. We may be unable to pass on increased compliance costs to our customers. Moreover, accidental releases, including spills, may occur in the course of our operations, and there can be no assurance 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 and natural resources or personal injury. While we do not believe that compliance with existing environmental laws and regulations and that continued compliance with existing requirements will have an adverse material effect on us, we can provide no assurance that we will not incur substantial costs in the future related to revised or additional environmental regulations that could have a material adverse effect on our business, financial condition, and results of operations.

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 subject and for which compliance may have a material adverse impact on the Company.

Hazardous Substances and Wastes

We currently own, lease, or operate, and in the past have owned, leased, or operated, properties that have been used in the exploration and production of oil and natural gas. We believe we have utilized operating and disposal practices that were standard in the industry at the applicable time, but hazardous substances, hydrocarbons, and wastes may have been disposed or released on, from or under the properties owned, leased, or operated by us or on or under other locations where these substances and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose storage treatment and disposal or release of hazardous substances, hydrocarbons, and wastes were not under our control. These properties and the substances or wastes disposed or released on them may be subject to the Comprehensive Environmental Response, Compensation, and Liability Act, as amended ("CERCLA"), the federal Resource Conservation and Recovery Act, ("RCRA"), and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed substances or wastes (including substances or wastes disposed of or released by prior owners or operators), to investigate and clean up contaminated property, to perform remedial actions to prevent future contamination, or to pay some or all of the costs of any such action.

CERCLA, also known as the Superfund law, and comparable state laws may impose strict, joint and several liability without regard to fault or legality of conduct on certain classes of persons who are considered to be responsible for the release of a “hazardous substance” into the environment. These persons include current and prior owners or operators of the site where the release of a hazardous substance occurred as well as entities that disposed or arranged for the disposal of the hazardous substances released at the site. Under CERCLA, these “responsible persons” may be liable for the costs of cleaning up sites where the hazardous substances have been released into the environment, for damages to natural resources resulting from the release and for the costs of certain environmental and health studies. Additionally, landowners and other third parties may file claims for personal injury and natural resource and property damage allegedly caused by the release of hazardous substances into the environment. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment from a hazardous substance release and to pursue steps to recover costs incurred for those actions from responsible parties. Despite the so-called “petroleum exclusion,” certain products used in the course of our operations may be regulated as CERCLA hazardous substances. To date, no Company-owned or operated site has been designated as a Superfund site, and we have not been identified as a responsible party for any Superfund site.

We also generate wastes that are subject to the requirements of RCRA and comparable state statutes. RCRA imposes strict “cradle-to-grave” requirements on the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Drilling fluids, produced waters and other wastes associated with the exploration, production and/or development of oil and natural gas, including naturally-occurring radioactive material, if properly handled, are currently excluded from regulation as hazardous wastes under RCRA and, instead, are regulated under RCRA’s less stringent non-hazardous waste requirements. However, it is possible that these wastes 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 the 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 the 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, and complete any revisions to the applicable RCRA regulations no later than July 15, 2021. Any change in the exclusion for such wastes could potentially result in an increase in costs to manage and dispose of wastes which could have a material adverse effect on our results of operations and financial position. In addition, in the course of our operations, we generate petroleum hydrocarbon wastes and ordinary industrial wastes that are subject to regulation under the RCRA if they have hazardous characteristics.

Air Emissions

The federal Clean Air Act (the “CAA”), as amended, and comparable state laws and regulations restrict the emission of air pollutants through emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. 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 air permit requirements or utilize specific equipment or technologies to control emissions. The need to acquire such permits has the potential to delay or limit the development of our oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues. For example, in October 2015, the EPA issued a final rule under the CAA, lowering the National Ambient Air Quality Standard for ground-level ozone to 70 parts per billion under both the primary and secondary standards to provide requisite protection of public health and welfare. The EPA was required to make attainment and non-attainment designations for specific geographic locations under the revised 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 recommendation for designating non-attainment areas. States then had the opportunity to submit new air quality monitoring to the EPA prior to the EPA finalizing any non-attainment designations. While the EPA has determined that all counties in which we operate are in attainment with the new ozone standard, these determinations may be revised in the future. With the EPA lowering the ground-level ozone standard, certain states may be required to implement more stringent regulations, which could apply to our operations and result in the need to install new emissions controls, longer permitting timelines and significant increases in our capital or operating expenditures. In addition, in June 2016, the EPA finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air-quality 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.

Water Discharges

The federal Water Pollution Control Act, also known as the Clean Water Act (the “CWA”), and analogous state laws and implementing regulations, impose restrictions and strict controls regarding the discharge of pollutants into waters of the United States. Pursuant to these laws and regulations, the discharge of pollutants into regulated waters is prohibited unless it is permitted by the EPA, the Army Corps of Engineers ("Corps") or an analogous state or tribal agency. We do not presently discharge pollutants associated with the exploration, development and production of oil and natural gas into federal or state waters. The CWA and analogous state laws and regulations also impose restrictions and controls regarding the discharge of sediment via storm water run-off from a wide variety of construction activities. Such activities are generally prohibited from discharging sediment unless permitted by the EPA or an analogous state agency. The EPA issued a final rule in September 2015 that attempts to clarify the federal jurisdictional reach over waters of the United States. The EPA and the Corps then proposed a rulemaking in June 2017 to repeal the June 2015 rule and also announced their intent to issue a new rule defining the CWA’s jurisdiction. The EPA and the Corps issued a final rule in January 2018 staying implementation of the 2015 rule for two years. Subsequently, on December 11, 2018, the EPA and the Corps proposed a new rule defining the CWA’s jurisdiction. A nationwide patchwork of litigation and court rulings developed regarding the rules. At this time, due to varied court rulings, the 2015 rule is effective in some states, while the agencies’ decision to delay implementation of the 2015 rule is effective in other states. If finalized, the 2018 proposed rule would apply nationwide, replacing the national patchwork of CWA jurisdictional applicability. Additionally, if finalized, it is possible that the 2018 proposed rule will be challenged. The scope of the CWA’s jurisdiction likely will remain fluid until a final regulatory determination is made and subsequent litigation, if any, is completed. To the extent a rule ultimately promulgated 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. Also, in June 2016, the EPA issued a final rule implementing wastewater pretreatment standards that prohibit onshore unconventional oil and natural gas extraction facilities from sending wastewater to publicly-owned treatment works. This restriction of disposal options for hydraulic fracturing waste and other changes to CWA requirements may result in increased costs.

Finally, the Oil Pollution Act of 1990 (“OPA”), which amends the CWA, establishes standards for prevention, containment and cleanup of oil spills into waters of the United States. The OPA requires measures to be taken to prevent the accidental discharge of oil into waters of the United States from onshore production facilities. Measures under the OPA and/or the CWA include inspection and maintenance programs to minimize spills from oil storage and conveyance systems; the use of secondary containment systems to prevent spills from reaching nearby water bodies; proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill; and the development and implementation of spill prevention, control and countermeasure (“SPCC”) plans to prevent and respond to oil spills. The OPA also subjects owners and operators of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a spill. We have developed and implemented SPCC plans for properties as required under the CWA.

Subsurface Injections

Underground injection operations performed by us are subject to the Safe Drinking Water Act (“SDWA”), as well as analogous state laws and regulations. Under the SDWA, the EPA established the Underground Injection Control (“UIC”) program, which established the minimum program requirements for state and local programs regulating underground injection activities. The UIC program includes requirements for permitting, testing, monitoring, record keeping 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 the Company monitors the injection process of its 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 resource and imposition of liability by third-parties claiming damages for alternative water supplies, property damages and personal injuries. Some states have considered laws mandating flowback and produced water recycling. Other states have undertaken studies to assess the feasibility of recycling produced water on a large scale. For example, in July 2018, the EPA partnered with New Mexico to assess alternatives to the immediate disposal of wastewater from exploration and production activities by reusing it or treating it for reintroduction into the hydrologic cycle or both, and to propose potential regulations related thereto. If such laws are adopted in areas where we conduct operations, our operating costs may increase significantly.

Furthermore, in response to recent seismic events near underground disposal wells used for the disposal by injection of produced water resulting from oil and natural gas activities, federal and some state agencies are investigating whether such wells have caused increased seismic activity, and some states have restricted, suspended or shut down the use of such disposal wells. For example, in Oklahoma, the Oklahoma Corporation Commission (“OCC”) has implemented a variety of measures including adopting 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 special 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 issued 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 2016, the OCC issued a plan to reduce disposal well volume in the Arbuckle formation by 40 percent, covering approximately 5,281 square miles and 245 disposal wells injecting wastewater into the Arbuckle formation. In the plan, the OCC identified 76 SandRidge-operated disposals wells, prescribed a four stage volume reduction schedule and set April 30, 2016 as the final date for compliance with the tiered volume reduction plan. In March 2016, the OCC reduced the injection volume of additional Arbuckle disposal wells, including wells we operate. Following earthquakes in August, September and November 2016, the OCC and the EPA further limited the disposal volumes that can be disposed in Arbuckle wells, although these actions did not cover our disposal wells. While induced seismic events generally decreased in 2017, the OCC expanded restrictions on the use of existing Arbuckle disposal wells and imposed new reporting requirements related to disposal volumes on wells injecting produced water into the Arbuckle formation. In February 2018, the OCC instituted a new protocol to further address seismicity in the Sooner Trend Anadarko Basin Canadian and Kingfisher County and South Central Oklahoma Oil Province Plays which requires various actions, such as a pause in operations for several hours, when certain seismic data is observed. Such requirements may reduce the productivity of our operations in relevant areas.

Additionally, the Governor of Kansas has established a task force composed of various administrative agencies to study and develop an action plan for addressing seismic activity in the state. The task force issued a recommended Seismic Action Plan calling for enhanced seismic monitoring and the development of a seismic response plan, and in November 2014, the Governor of Kansas announced a plan to enhance seismic monitoring in the state. In March 2015, the Kansas Corporation Commission issued its Order Reducing Saltwater Injection Rates (the "Order"). The Order identified five areas of heightened seismic concern within Harper and Sumner Counties and mandated that, within 100 days of the Order’s issuance, operators must limit saltwater injection volumes to no more than 8,000 barrels per day for any well located in one of these five areas. SandRidge and other operators of injection wells were required to reduce the injection volume, and any injection well drilled deeper than the Arbuckle Formation was required to be plugged back to a shallower formation in a manner approved by the Kansas Corporation Commission. In August 2016, the Kansas Corporation Commission issued an order that put a 16,000 barrels per day limit on additional Arbuckle disposal wells not previously identified in the Order. While no additional regulatory actions were taken in Kansas with respect to induced seismicity concerns in 2017 or 2018, permit applications for new saltwater disposal well facilities have faced increased local opposition.

Evaluation of seismic incidents and whether or to what extent those events are induced by the injection of saltwater into disposal wells continues to evolve, as governmental authorities consider new and/or past seismic incidents in areas where salt 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 saltwater generated by production and development activities , whether by plugging back the depths of disposal wells, reducing the volume of salt water disposed in such wells, restricting disposal well locations or otherwise, or by requiring us to shut down disposal wells, could significantly increase our costs to manage and dispose of this saltwater, which could negatively affect the economic lives of the affected properties. In addition, we could find ourselves subject to third party lawsuits alleging damages resulting from seismic events that occur in our areas of operation.

Climate Change

The EPA previously has published its findings that emissions of CO_2, methane and certain other “greenhouse gases” ("GHGs") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. Based on its findings, the EPA has adopted and implemented regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration (“PSD”) construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emission. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards that typically are established by the states. This rule could adversely affect our operations and restrict or delay its ability to obtain air permits for new or modified facilities that exceed GHG emission thresholds. In addition, the EPA has adopted rules requiring the reporting of GHG emissions from oil and natural gas production and processing facilities on an annual basis, as well as reporting GHG emissions from gathering and boosting systems, oil well completions and workovers using hydraulic fracturing. More recently, in June 2016, the EPA finalized rules to reduce methane emissions from new, modified or reconstructed sources in the oil and natural gas sector, including implementation of a leak detection and repair ("LDAR") program to minimize methane emissions, under the CAA's New Source Performance Standards, Subpart OOOOa ("Quad Oa"). In June 2017, the EPA proposed a two-year stay of the rules and in October 2018 the EPA proposed revisions to Quad Oa, such as changes to the frequency for monitoring fugitive emissions at well sites and changes to requirements that a professional engineer certify when meeting certain Quad Oa requirements is technically infeasible. Regardless of the stay and potential regulatory revisions, it is possible that these rules will continue to require oil and gas operators to expend material sums. In addition, in November 2016, the U.S. Department of the Interior Bureau of Land Management ("BLM") issued final rules to reduce methane emissions from venting, flaring, and leaks during oil and natural gas operations on public lands that are substantially similar to the EPA Quad Oa requirements. However, in December 2017, the BLM published a final rule to temporarily suspend or delay certain requirements contained in the November 2016 final rule until January 17, 2019, including those requirements relating to venting, flaring and leakage from oil and gas production activities. Further, in September 2018, the BLM published a final rule revising or rescinding certain provisions of the 2016 rule. As a result of these developments, future implementation of the EPA and the BLM methane rules remains uncertain, but given the long-term trend towards increasing regulation, future federal GHG regulations for the oil and gas industry remain a possibility. Moreover, several states where we operate, including Colorado, have already adopted rules requiring operators of both new and existing sources to develop and implement a LDAR program and to install devices on certain equipment to capture 95 percent of methane emissions. Compliance with these rules could require us to purchase pollution control equipment and optical gas imaging equipment for LDAR inspections, and to hire additional personnel to assist with inspection and reporting requirements.

In addition, a number of state and regional efforts are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs 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 agreed in December 2015 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 measure each country will use to achieve its GHG emissions targets, (the "Paris Agreement"). However, the Paris Agreement does not impose any binding obligations on the United States. Moreover, in June 2017, President Trump announced that the United States would withdraw from the Paris Agreement, but may enter into a future international agreement related to GHGs. In August 2017, the U.S. State Department officially informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. Such withdrawal has not yet been finalized, and whether the United States may reenter the Paris Agreement or a separately negotiated agreement is unclear at this time. Further, several states and local governments remain committed to the principles of the Paris Agreement in their effectuation of policy and regulations. It is not possible at this time to predict how or when the United States might impose restrictions on GHGs as a result of the Paris Agreement. The adoption and implementation of any laws or regulations imposing reporting obligations on, or limiting emissions of GHG from, our equipment and operations could require additional expenditures to reduce emissions of GHGs associated with its operations or could adversely affect demand for the oil and natural gas we produce, and thus possibly have a material adverse effect on our revenues, as well as having the potential effect of lowering the value of our reserves. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel 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, to the extent 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, droughts, floods and other climatic events, such events could have a material adverse effect on the Company and potentially subject the Company to further regulation.

Endangered or Threatened Species

The federal Endangered Species Act (the “ESA”) restricts activities that may affect endangered or threatened species or their habitats without first obtaining an incidental take permit and implementing mitigation measures. Similar protections are offered to migratory birds under the federal Migratory Bird Treaty Act. While compliance with the ESA has not had an adverse effect on our exploration, development and production operations in areas where threatened or endangered species or their habitat are known to exist, it may require us to incur increased costs to implement mitigation or protective measures and also may delay, restrict or preclude drilling activities in those areas or during certain seasons, such as breeding and nesting seasons. In addition, certain of our federal and state leases may contain stipulations that require us to take measures to safeguard certain species, including the sage grouse, and their habitats known to be located within the area of the lease. Although the U.S. Fish and Wildlife Service (“USFWS”) declined to list the sage grouse under the ESA in 2015 and subsequently developed a conservation plan to protect existing habit, some environmental groups have continued to raise concerns about sufficient protections for the sage grouse population. Under the plan, the USFWS committed to review the status of the species every five years to evaluate conservation actions, with the plan to be next reviewed and revised if necessary in 2020. In addition, the U.S. Department of Interior ("DOI") proposed in December 2018 revisions to the existing sage grouse conservation plan that, amongst other things, was intended to give the DOI and individual states flexibility to allow for increased activity in grouse habitat management areas encompassing parts of Colorado, Idaho, Nevada, Northern California, Oregon, Utah and Wyoming. Several environmental groups have announced opposition to DOI's proposed revisions to sage grouse conservation plan, and it is possible that these groups could pursue new litigation in the future to reconsider listing the sage grouse under the ESA. If endangered or otherwise protected species are located in areas where we wish to conduct seismic surveys, development activities or abandonment operations, the work could be prohibited or delayed or expensive mitigation may be required. For example, certain of our operations in Colorado are in proximity to sage grouse habitat and we are prohibited from performing operations in those areas during certain hours from March to mid-July of each year. Further, in February 2016, the USFWS published a final policy which alters how it identifies critical habitats for endangered and threatened species. In July 2018, the USFWS proposed several changes to ESA regulations, including changes to the procedures and criteria for listing or removing species from the Lists of Endangered and Threatened Wildlife and Plants and for designating critical habitat. A critical habitat designation could result in further material restrictions to federal and private land use and could delay or prohibit land access or development. Moreover, a settlement approved by the U.S. District Court for the District of Columbia in 2011 required the USFWS to consider listing numerous species as endangered under the ESA by the end of its 2017 fiscal year; however, the agency has not yet completed this process.

The 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 exploration and production activities that could have an adverse impact on our ability to develop and produce our reserves.

We are an active participant on various agency and industry committees that are developing or addressing various USFWS and other federal and state agency programs to minimize potential impacts to business activity relating to the protection of any endangered or threatened species.

Employee Health and Safety

Our operations are subject to a number of federal and state laws and regulations, including the federal 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 requires us to maintain information concerning hazardous materials used or produced in our operations and to provide this information to employees. Pursuant to the Federal Emergency Planning and Community Right-to-Know Act, facilities that store threshold amounts of chemicals that are subject to OSHA's Hazard Communication Standard above certain threshold quantities must submit information regarding those chemicals by March 1 of each year to state and local authorities in order to facilitate emergency planning and response. That information is generally available to employees, state and local governmental authorities, and the public. We do not believe that compliance with applicable laws and regulations relating to worker health and safety will have a material adverse effect on our business and results of operations.

State Regulation

The states in which we operate, along with some municipalities and Native American tribal areas, regulate some or all of the following activities: the drilling for, and the production and gathering of, oil and natural gas, including requirements relating to drilling permits, the location, spacing and density of wells, unitization and pooling of interests, the method of drilling, casing and equipping of wells, the protection of fresh water sources, the orderly development of common sources of supply of oil and natural gas, the operation of wells, allowable rates of production, the use of fresh water in oil and natural gas operations, saltwater injection and disposal operations, the plugging and abandonment of wells and the restoration of surface properties, the prevention of waste of oil and natural gas resources, the protection of the correlative rights of oil and natural gas owners and, where necessary to avoid unfair, unjust or discriminatory service, the fees, terms and conditions for the gathering of natural gas. These regulations may affect the number and location of our wells and the amounts of oil and natural gas that may be produced from our wells, and increase the costs of our operations. Moreover, obtaining or renewing permits and other approvals for operating on Native American lands can take substantial amounts of time, and could result in increased costs or delays to our operations.

Hydraulic Fracturing

Hydraulic fracturing is a practice in the oil and natural gas industry used to stimulate production of natural gas and/or oil from low permeability subsurface rock formations. Oil and natural gas may be recovered from certain of our oil and natural gas properties through the use of hydraulic fracturing, combined with sophisticated drilling. Hydraulic fracturing, which involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production, is typically regulated by state oil and natural gas commissions. However, several federal agencies have asserted federal regulatory authority over certain aspects of the hydraulic fracturing process. For example, the EPA published permitting guidance in February 2014 addressing the use of diesel fuel in fracturing operations; issued CAA final regulations in 2012 and additional CAA regulations in June 2016 governing performance standards for the oil and natural gas industry; and in June 2016 issued final effluent limitations guidelines under the CWA that waste water from shale natural gas extraction operations must meet before discharging to a publicly-owned treatment plant. The EPA also issued an Advance Notice of Proposed Rulemaking under the Toxic Substances Control Act ("TSCA") in 2014 regarding reporting of the chemical substances and mixtures used in hydraulic fracturing but, to date, has taken no further action. Separately, the BLM published a final rule in March 2015 that establishes new or more stringent standards for performing hydraulic fracturing on federal and Indian lands. However, the U.S. District Court of Wyoming struck down this rule in June 2016. The June 2016 decision was appealed by the BLM to the U.S. Circuit Court of Appeals for the Tenth Circuit. However, following issuance of a presidential executive order to review rules related to the energy industry, in July 2017, the BLM published a proposed rule to rescind the 2015 final rule. In September 2017, the Tenth Circuit issued a ruling to vacate the Wyoming trial court decision and dismiss the lawsuit challenging the 2015 rule in light of the BLM's proposed rulemaking. The BLM issued a final rule repealing the 2015 hydraulic fracturing rule in December 2017.

Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process but, at this time, federal legislation related to hydraulic fracturing appears unlikely. At the state level, some states, including Oklahoma and Colorado, 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 government 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, our fracturing activities could become subject to additional permit and financial assurance requirements, more stringent construction requirements, increased reporting or plugging and abandoning requirements or operational restrictions, and associated permitting delays and potential increases in costs. These delays or additional costs could adversely affect the determination of whether a well is commercially viable, and could cause us to incur substantial compliance costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce in commercial quantities.

In addition to asserting regulatory authority, certain government agencies have conducted reviews focusing on environmental issues associated with hydraulic fracturing practices. For example, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources in December 2016. The EPA report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water sources "under some circumstances," noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than 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. Since 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.

We diligently review best practices and industry standards, serve on industry association committees and comply with all regulatory requirements in the protection of potable water sources. Protective practices include, but are not limited to, setting multiple strings of protection pipe across the potable water sources and cementing these pipes from setting depth to surface, continuously monitoring the hydraulic fracturing process in real time and disposing of all non-commercially produced fluids in certified disposal wells at depths below the potable water sources. There have not been any incidents, citations or suits related to our hydraulic fracturing activities involving environmental concerns.

OTHER REGULATION OF THE OIL AND NATURAL GAS INDUSTRY

The oil and natural gas industry is extensively regulated by numerous federal, state, local, and regional authorities, as well as Native American tribes. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, and Native American tribes are authorized by statute to issue rules and regulations affecting the oil and natural gas industry and its individual members, some of which carry substantial penalties for noncompliance. Although the regulatory burden on the oil and natural gas industry increases the Company's cost of doing business and, consequently, affects its profitability, these burdens generally do not affect the Company any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

The price of oil, natural gas and NGLs is not currently regulated and are made at market prices. Although oil, natural gas and NGL prices are currently unregulated, Congress historically has been active in the area of oil and natural gas regulation. We cannot predict whether new legislation to regulate oil, natural gas and NGL prices might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on our operations.

Drilling and Production

Our operations are subject to various types of regulation at federal, state, local and Native American tribal levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties, municipalities and Native American tribal areas where we operate also regulate one or more of the following activities:

- the location of wells;
- the method of drilling and casing wells;
- the timing of construction or drilling activities;
- the rates of production, or "allowables";
- the use of surface or subsurface waters;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- the notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas, and NGLs within its jurisdiction.

State agencies in Colorado, Kansas, Oklahoma and Texas impose financial assurance requirements on operators. The Corps and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration.

Natural Gas Sales and Transportation

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation and sale for resale of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission ("FERC"). Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. The FERC's regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production. FERC has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 (the “NGA”) and the Natural Gas Policy Act of 1978. Various federal laws enacted since 1978 have resulted in the removal of all price and non-price controls for sales of domestic natural gas sold in first sales, which include all of our sales of our own production. Under the Energy Policy Act of 2005 (the “EPAct 2005”), FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties of up to $1,238,271 per day for each violation and disgorgement of profits associated with any violation. While our systems have not been regulated by FERC as a natural gas company under the NGA, we are required to report aggregate volumes of natural gas purchased or sold at wholesale to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. In addition, Congress may enact legislation or FERC may adopt regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to further regulation. Failure to comply with those regulations in the future could subject us to civil penalty liability.

The Commodity Futures Trading Commission (the "CFTC") also holds authority to monitor certain segments of the physical and futures energy commodities market including oil and natural gas. With regard to physical purchases and sales of natural gas and other energy commodities, and any related hedging activities that we undertake, we are thus required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the CFTC. The CFTC also holds substantial enforcement authority, including the ability to assess civil penalties of up to $1,116,156 per day per violation.

FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which we may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas and release of our natural gas pipeline capacity. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Currently, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC's initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, the less stringent regulatory approach currently pursued by FERC and Congress might not continue indefinitely into the future. The Company is unable to determine what effect, if any, future regulatory changes might have on the Company's natural gas related activities.

Under FERC's current regulatory regime, transmission services must be provided on an open-access, nondiscriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in-state waters. Although its policy is still in flux, in the past FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our cost of transporting gas to point-of-sale locations.

Oil Price Controls and Transportation Rates

Sales prices of oil and NGLs are not currently regulated and are made at market prices. Our sales of these commodities are, however, subject to laws and to regulations issued by the Federal Trade Commission (the "FTC") prohibiting manipulative or fraudulent conduct in the wholesale petroleum market. The FTC holds substantial enforcement authority under these regulations, including the ability to assess civil penalties of up to $1,156,953 per day per violation. Our sales of these commodities, and any related hedging activities, are also subject to CFTC oversight as discussed above.

The price we receive from the sale of these products may be affected by the cost of transporting the products to market. Some of our transportation of oil, natural gas and NGLs is through interstate common carrier pipelines. Effective as of January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. The FERC's regulation of crude oil and natural gas liquids transportation rates may tend to increase the cost of transporting crude oil and natural gas liquids by interstate pipelines, although the annual adjustments may result in decreased rates in a given year. Every five years, the FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry. We are not able at this time to predict the effects of these regulations or FERC proceedings, if any, on the transportation costs associated with crude oil production from our crude oil producing operations.

EMPLOYEES

As of December 31, 2018, the Company had 310 full-time employees, including 48 geologists, geophysicists, petroleum engineers, technicians, land and regulatory professionals. Of our 310 employees, 163 were located at the Company’s headquarters in Oklahoma City, Oklahoma at December 31, 2018, and the remaining employees worked in our various field offices and drilling sites.

Item 1A. ***Risk Factors***

An investment in our common stock involves certain risks. If any of the following key risks were to develop into actual events, it could have a material adverse effect on our financial position, results of operations and cash flows. In any such circumstance and others described below, the trading price of our securities could decline and you could lose part or all of your investment.

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

Oil, natural gas and NGL prices can fluctuate widely due to a number of factors that are beyond our control. Declines in oil, natural gas or NGL prices could significantly affect our financial condition and results of operations.

Our revenues, profitability and cash flow are highly dependent upon the prices we realize from the sale of oil, natural gas and NGLs. Historically, the markets for these commodities are very volatile. Prices for oil, natural gas and NGLs can move quickly and fluctuate widely in response to a variety of factors that are beyond our control. These factors include, among others:

•changes in regional, domestic and foreign supply of, and demand for, oil, natural gas and NGLs, as well as perceptions of supply of, and demand for, oil, natural gas and NGLs generally;
•the price and quantity of foreign imports;
•the ability of other companies to complete and commission liquefied natural gas export facilities in the U.S.;
•U.S. and worldwide political and economic conditions;
•the level of global and U.S. inventories;
•weather conditions and seasonal trends;
•anticipated future prices of oil, natural gas and NGLs, alternative fuels and other commodities;
•technological advances affecting energy consumption and energy supply;
•the proximity, capacity, cost and availability of pipeline infrastructure, treating, transportation and refining capacity;
•natural disasters and other extraordinary events;
•domestic and foreign governmental regulations and taxation;
•energy conservation and environmental measures; and
•the price and availability of alternative fuels.

These factors and the volatility of the energy markets, which we expect will continue, make it extremely difficult to predict future oil, natural gas and NGL price movements with any certainty. For oil, from January 2014 through December 2018, the NYMEX settled price fluctuated between a high of $107.26 per Bbl and a low of $26.21 per Bbl. For natural gas, from January 2014 through December 2018, the month-end NYMEX settled price fluctuated between a high of $5.56 per MMBtu and a low of $1.71 per MMBtu. In addition, the market price of natural gas is generally higher in the winter months than during other months of the year due to increased demand for natural gas for heating purposes during the winter season.

Although oil, natural gas and NGL prices rose during 2018, a buildup in inventories, lower global demand, or other factors could cause prices for U.S. oil, natural gas and NGLs to weaken, which could negatively affect our cash flows and results of operations. Under such conditions, revenues may be negatively affected, and the amount of oil, natural gas and NGLs we can produce economically may be reduced, causing us to make substantial downward adjustments to our estimated proved reserves and having a material adverse effect on our financial condition and results of operations.

Unless we replace our oil, natural gas and NGL reserves, our reserves and production will decline, which would adversely affect our business, financial condition and results of operations.

Our future oil, natural gas and NGL reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current estimated proved reserves and finding or acquiring additional economically recoverable reserves. Declining cash flows from operations, as a result of lower commodity prices, could require us to reduce expenditures to develop and acquire additional reserves. Further, we may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs, which could adversely affect our business, financial condition and results of operations.

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

Drilling for oil and natural gas can be unprofitable if dry wells are drilled and if productive wells do not produce sufficient revenues to return a profit. Furthermore, even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. Decisions to develop properties 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. The estimated cost of drilling, completing and operating wells is uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of various factors, including the following:

- reductions in oil, natural gas and NGL prices;
- delays imposed by or resulting from compliance with regulatory requirements including permitting;
- unusual or unexpected geological formations and miscalculations;
- shortages of or delays in obtaining equipment and qualified personnel;
- shortages of or delays in obtaining water and sand for hydraulic fracturing operations;
- equipment malfunctions, failures or accidents;
- lack of available gathering or midstream facilities or delays in construction of gathering or midstream facilities;
- lack of available capacity on interconnecting transmission pipelines;
- lack of adequate electrical infrastructure and water disposal capacity;
- unexpected operational events and drilling conditions;
- pipe or cement failures and casing collapses;
- pressures, fires, blowouts and explosions;
- lost or damaged drilling and service tools;
- loss of drilling fluid circulation;
- uncontrollable flows of oil, natural gas, brine, water or drilling fluids;
- natural disasters;
- environmental hazards, such as oil spills and natural gas leaks, pipeline or tank ruptures, encountering naturally occurring radioactive materials and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- high costs, shortages or delivery delays of equipment, labor or other services, or water used in hydraulic fracturing;
- compliance with environmental and other governmental requirements;
- adverse weather conditions such as extreme cold, fires caused by extreme heat or lack of rain, and severe storms, tornadoes or hurricanes;
- oil and natural gas property title problems; and
- market and midstream limitations for oil, natural gas and NGLs.

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.

Market conditions or operational impediments may hinder our access to oil, natural gas and NGL markets or delay production of oil, natural gas and NGLs.

Market conditions or a lack of satisfactory oil and natural gas transportation arrangements may hinder our access to oil, natural gas and NGL markets or delay production of oil, natural gas and NGLs. The availability of a ready market for our oil, natural gas and NGL production depends on a number of factors, including the demand for and supply of oil, natural gas and NGLs and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends, in substantial part, on the availability and capacity of gathering systems, pipelines and treating facilities for oil, natural gas and NGLs as well as gathering systems, treating facilities and disposal wells for water produced alongside the hydrocarbons. Our failure to obtain such services on acceptable terms in the future or to expand our midstream assets could have a material adverse effect on our business. We may be required to shut in wells for a lack of a market or because access to natural gas pipelines, gathering system capacity, treating facilities or disposal wells may be limited or unavailable. We would be unable to realize revenue from any shut-in wells until production arrangements were made to deliver the production to market.

Our North Park Basin acreage may require the construction of significant gathering systems and pipelines as we increase drilling and development activity. Obtaining these services or expanding our midstream assets with acceptable commercial terms could adversely affect our ability to develop this acreage in a timely manner.

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

Our management team has specifically identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering and midstream system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the numerous potential well locations we have identified will ever be drilled or if we will be able to produce natural gas or oil from these or any other potential locations. For example, our North Park Basin assets are in the delineation phase of the development cycle and may require significant investment over the next several years, including the construction of midstream and pipeline takeaway infrastructure, as we progress toward full field development with more activity and an expanded development footprint. We may not be able to raise the substantial amount of capital necessary to fully realize our North Park Basin assets.

In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

Our acreage not contained within federal units must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production, and our acreage committed to federal units must be drilled pursuant to the federal unit timelines provided within the unit agreements. In a highly competitive market for acreage, failure to drill sufficient wells to hold acreage may result in a substantial lease renewal cost, or if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Leases on our oil and natural gas properties that are not federal units typically have a term of three to five years, after which they expire unless, prior to expiration, production is established within the spacing units covering the undeveloped acres, or the leases are renewed. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. Acreage committed to federal units must be drilled pursuant to the federal unit timelines provided within the unit agreements, typically requiring two unit wells within the first 5 years and two more wells within the next five years. At the end of the second five-year term the unit begins to reduce in size to designated participating areas within the Federal Units. Unless we increase our current drilling program, we could lose undeveloped acreage through lease expirations. Our reserves and future production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage and the loss of any leases could materially and adversely affect our ability to so develop such acreage.

Our development and exploration operations require substantial capital. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our oil, natural gas and NGL reserves.

The oil and natural gas industry is capital intensive. We make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of oil, natural gas and NGL reserves. Historically, we have financed capital expenditures primarily with proceeds from asset sales and from the sale of equity and debt securities and cash generated by operations. In particular, cash flow operations was and $181.2 million for the years ended December 31, 2018, and 2017, respectively. Cash flow from operations was $65.6 million for the Successor 2016 Period, and cash used in operations was $112.1 million for the Predecessor 2016 Period.

The capital markets that we have historically accessed have recently been and may continue to be constrained to such an extent that debt or equity capital raises are practically unfeasible. Similarly, failure to renew or replace our credit facility prior to its maturity on March 31, 2020 could negatively impact our liquidity. If the debt and equity capital markets are not accessible or if our ability to draw on our credit facility is compromised, we may be unable to implement our drilling and development plans or otherwise carry out our business strategy as expected. Our cash flow from operations and access to capital are subject to a number of variables, including:

- the prices at which oil, natural gas and NGLs are sold;
- our proved reserves;
- the level of oil, natural gas and NGLs we are able to produce from existing wells;
- our ability to acquire, locate and produce new reserves; and
- our capital and operating costs.

Based on our 2019 capital spending plans, we estimate that our production will experience a 5%- 6% decline. This decline in production as well as other factors such as lower oil, natural gas and NGL prices, declines in reserves, or for any other reason may lead to reductions in our revenues and cash flow from operations and may limit our ability to obtain the capital necessary to sustain our operations at desired levels. In order to fund capital expenditures, we may seek additional financing.

Disruptions in the global financial and capital markets could also adversely affect our ability to obtain debt or equity financing on favorable terms, or at all. The failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of its prospects, which in turn could lead to a possible loss of properties and a decline in our oil, natural gas and NGL reserves.

Future price declines may result in reductions of the asset carrying values of our oil and natural gas properties.
We utilize the full cost method of accounting for costs related to our oil and natural gas properties. Under this accounting method, all costs for both productive and nonproductive properties are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the unit-of-production method. However, the amount of these costs that can be carried as capitalized assets is subject to a ceiling, which limits such pooled costs to the aggregate of the present value of future net revenues of proved oil, natural gas and NGL reserves attributable to proved properties, discounted at 10%, plus the lower of cost or market value of unevaluated properties. The full cost ceiling is evaluated at the end of each quarter using the SEC prices, adjusted for the impact of derivatives accounted for as cash flow hedges. The Successor Company did not incur any full cost ceiling impairment charges for the years ended December 31, 2018 or 2017. During the Successor 2016 Period, and the Predecessor 2016 Period, we incurred full cost ceiling impairment charges of $319.1 million and $657.4 million, respectively. Cumulative full cost ceiling impairment from the Emergence date through December 31, 2018 totaled $319.1 million, respectively. If oil, natural gas and NGL prices decline further in the near term, and without other mitigating circumstances, we may experience additional losses of future net revenues, including losses attributable to quantities that cannot be economically produced at lower prices, which would likely cause us to record additional write-downs of capitalized costs of its oil

and natural gas properties and non-cash charges against future earnings. The amount of such future write-downs and non-cash charges could be substantial. Further, the borrowing base under our credit facility is calculated by reference to the value of our oil and natural gas reserves, as determined by the lenders under the credit facility, and declines in the value of such reserves as a result of sustained low commodity prices could reduce the amount available to be borrowed under our credit facility if prices decline from current levels.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities and present value of our reserves. Our current estimates of reserves could change, potentially in material amounts, in the future.
The process of estimating oil, natural gas and NGL reserves is complex and inherently imprecise, requiring interpretations of available technical data and many assumptions, including assumptions relating to production rates and economic factors such as historic oil and natural gas prices, drilling and operating expenses, capital expenditures, the assumed effect of governmental regulation and availability of funds for development expenditures. Inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves. See "Business—Primary Business Operations" in Item 1 of this report for information about our oil, natural gas and NGL reserves.

Actual future production, oil, natural gas and NGL prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil, natural gas and NGL reserves will vary and could vary significantly from our estimates shown in this report, which in turn could have a negative effect on the value of our assets. In addition, from time to time in the future, we will adjust estimates of proved reserves, potentially in material amounts, to reflect production history, results of exploration and development, changes in oil, natural gas and NGL prices and other factors, many of which are beyond our control.

The ability to attract and retain key personnel is critical to the success of our business and the loss of senior management or technical personnel or our inability to hire additional qualified personnel could adversely affect our operations.
The success of our business depends on key personnel, including members of senior management and technical personnel. The ability to attract and retain these key personnel may be difficult in light of the uncertainties currently facing the business and changes we may make to the organizational structure to adjust to changing circumstances. The market for qualified personnel has historically been, and we expect that it will continue to be, intensely competitive. We cannot assure you that we will be successful in attracting or retaining such personnel. We may need to enter into retention or other arrangements that could be costly to maintain. If executives, managers or other key personnel resign, retire or are terminated, or their service is otherwise interrupted, we may not be able to replace them in a timely manner and we could experience significant declines in productivity.

The agreements governing our credit facility have restrictions, financial covenants and borrowing base redeterminations, which could adversely affect our operations.
The agreements governing our credit facility restrict our ability to, among other things, obtain additional financing, incur liens, enter into sale and lease back transactions, make certain investments, lease equipment, merge, dissolve, liquidate or consolidate with another entity, pay dividends or make other distributions or repurchase or redeem our stock, enter into transactions with our affiliates, create additional subsidiaries, amend or modify certain provisions of our organizational documents, enter into new transactions with our affiliates, sell assets and engage in business combinations. The credit facility also requires us to comply with certain financial covenants and ratios. See additional discussion of the credit facility under *"Indebtedness—Credit Facilities."* Persistent depressed oil or natural gas prices or further decline in such prices, without other mitigating circumstances, could prevent us from complying with the financial covenants under the credit facility. Our failure to comply with any of the restrictions and covenants under the credit facility or other debt financings could result in a default under those instruments, which, if left uncured, could lead to an event of default. Such an event of default could, among other things, result in all of our existing indebtedness becoming immediately due and payable. Additionally, an event of default under one of our financing instruments could trigger cross-default provisions under our other financing instruments. The application of the remedies under the financing instruments could have a material adverse effect on our financial position.

Our credit facility limits the amounts we can borrow to a borrowing base amount. The borrowing base is subject to review semi-annually; however, the lenders reserve the right to have one additional redetermination of the borrowing base per calendar year. Unscheduled redeterminations may be made at our request, but are limited to two requests per year. Borrowing base determinations are based upon proved developed producing reserves, proved developed non-producing reserves and proved undeveloped reserves. Outstanding borrowings exceeding the borrowing base must be repaid promptly, or we must pledge other oil and natural gas properties as additional collateral. The borrowing base is also subject to reductions upon the incurrence of junior debt, hedge terminations, dispositions of assets and casualty events which may require us to repay any deficiencies or pledge additional collateral. We may not have the financial resources in the future to make any mandatory principal prepayments under the credit facility, which are required, for example, when the committed line of credit is exceeded, proceeds of asset sales in new oil and natural gas properties are not reinvested, or indebtedness that is not permitted by the terms of the credit facility is incurred. If any future indebtedness under our credit facility were to be accelerated, our assets may not be sufficient to repay such indebtedness in full.

It is unclear how changes in the regulation of LIBOR or the discontinuation of LIBOR all together may affect our financing costs in the future.

Our credit facility bears interest based on a pricing grid tied to the London Interbank Offered Rate (“LIBOR”). On July 27, 2017, the United Kingdom’s Financial Conduct Authority (the "FCA"), which regulates LIBOR, announced that it does not intend to continue to persuade, or use its powers to compel, panel banks to submit rates for the calculation of LIBOR after 2021. It is not possible to predict whether, and to what extent, panel banks will continue to provide LIBOR submissions to the administrator of LIBOR after this time, which may cause LIBOR to perform differently than it did in the past and have other consequences which cannot be predicted.

In addition, any other legal or regulatory changes made by the FCA, ICE Benchmark Administration Limited, the European Money Markets Institute (formerly Euribor-EBF), the European Commission or any other successor governance or oversight body, or future changes adopted by such body, in the method by which LIBOR is determined or the transition from LIBOR to a successor benchmark may result in, among other things, a sudden or prolonged increase or decrease in LIBOR, a delay in the publication of LIBOR, and changes in the rules or methodologies in LIBOR, which may discourage market participants from continuing to administer or to participate in LIBOR’s determination. This could result in LIBOR no longer being determined and published. If a published U.S. dollar LIBOR rate is unavailable after 2021, the interest rate on our credit facility will need to be determined using alternative methods, which may result in interest obligations which are more than or do not otherwise correlate over time with the payments that would have been made on any outstanding debt under the facility if U.S. dollar LIBOR was available in its current form. Further, the same costs and risks that may lead to the discontinuation or unavailability of U.S. dollar LIBOR may make one or more alternative methods of calculating interest impossible or impracticable to determine. As a result, any of these consequences may have an adverse effect on our financing costs.

The present value of future net cash flows from our proved reserves calculated in accordance with SEC guidelines are not the same as the current market value of our estimated oil, natural gas and NGL reserves.

We base the estimated discounted future net cash flows from our proved reserves on 12-month average index prices and costs, as is required by SEC rules and regulations. Actual future net cash flows from our oil and natural gas properties will be affected by actual prices we receive for oil, natural gas and NGLs, as well as other factors such as:

- the accuracy of our reserve estimates;
- the actual cost of development and production expenditures;
- the amount and timing of actual production;
- supply of and demand for oil, natural gas and NGLs; and
- changes in governmental regulation or taxation.

The timing of both our production and incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, we use a 10% discount factor when calculating discounted future net cash flows, which may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

We will not know conclusively prior to drilling whether oil or natural gas will be present in sufficient quantities to be economically producible.

The cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive or may suffer from declining production faster than anticipated. The use of seismic data and other technologies and the study of producing fields in the same area do not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. During 2018, we completed a total of 29 gross wells, none of which were identified as dry wells. If we drill additional wells that we identify as dry wells in our current and future prospects, our drilling success rate may decline and materially harm our business.

Production of oil, natural gas and NGLs could be materially and adversely affected by natural disasters or severe weather.

Production of oil, natural gas and NGLs could be materially and adversely affected by natural disasters or severe weather. Repercussions of natural disasters or severe weather conditions may include:

- evacuation of personnel and curtailment of operations;

•damage to drilling rigs or other facilities, resulting in suspension of operations;
•inability to deliver materials to worksites; and
•damage to, or shutting in of, pipelines and other transportation facilities.

In addition, our hydraulic fracturing operations require significant quantities of water. Regions in which we operate have recently experienced drought conditions. Any diminished access to water for use in hydraulic fracturing, whether due to usage restrictions or drought or other weather conditions, could curtail our operations or otherwise result in delays in operations or increased costs.

The capital markets could be volatile, and such volatility could adversely affect our ability to obtain capital, cause us to incur additional financing expense or affect the value of certain assets.
During and following the 2008 global financial crisis, financial and capital markets were volatile due to multiple factors, including significant losses in the financial services sector and uncertain and rapidly changing economic conditions both in the U.S. and globally. In some cases, financial markets produced downward pressure on stock prices and credit capacity for certain issuers without regard to those issuers' underlying financial and/or operating strength. Volatility in the capital markets can significantly increase the cost of raising money in the debt and equity capital markets. Future market volatility, generally, and persistent weakness in commodity prices may adversely affect our ability to access capital and credit markets or to obtain funds at low interest rates or on other advantageous terms. These factors may adversely affect our business, results of operations or liquidity.

These factors may also adversely affect the value of certain of our assets and ability to draw on our credit facility. Adverse credit and capital market conditions may require us to reduce the carrying value of assets associated with derivative contracts to account for non-performance by, or increased credit risk from, counterparties to those contracts. If financial institutions that extended credit commitments to us are adversely affected by volatile conditions of the U.S. and international capital markets, they may become unable to fund borrowings under their credit commitments to us, which could have a material adverse effect on our financial condition and ability to borrow additional funds, if needed, for working capital, capital expenditures and other corporate purposes.

Properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them.
Our initial technical reviews of properties we acquire are necessarily limited because an in-depth review of every individual property involved in each acquisition generally is not feasible. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well and environmental problems, such as soil or ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, we may assume certain environmental and other risks and liabilities in connection with acquired properties, and such risks and liabilities could have a material adverse effect on our results of operations and financial condition.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate.
As of December 31, 2018, approximately 42.4% of our total reserves were proved undeveloped reserves. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Therefore, recoveries from these fields may not match current expectations. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves.

A significant portion of our operations are located in the Mid-Continent region, making us vulnerable to risks associated with operating in a limited number of major geographic areas.

As of December 31, 2018, approximately 69.2% of our proved reserves and approximately 88.6% of our annual production was located in the Mid-Continent. This concentration could disproportionately expose us to operational and regulatory risk in these areas. This relative lack of diversification in location of our key operations could expose us to adverse developments in the Mid-Continent or the oil and natural gas markets, including, for example, transportation or treatment capacity constraints, curtailment of production due to weather, electrical outages, treatment plant closures for scheduled maintenance, changes in the regulatory environment or other factors. These factors could have a significantly greater impact on our financial condition, results of operations and cash flows than if our properties were more diversified.

Oil and natural gas wells are subject to operational hazards that can cause substantial losses for which we may not be adequately insured.

There are a variety of operating risks inherent in oil, natural gas and NGL production and associated activities, such as fires, leaks, explosions, mechanical problems, major equipment failures, blowouts, uncontrollable flow of oil, natural gas and NGLs, water or drilling fluids, casing collapses, abnormally pressurized formations and natural disasters. The occurrence of any of these or similar accidents that temporarily or permanently halt the production and sale of oil, natural gas and NGLs at any of our properties could have a material adverse impact on our business activities, financial condition and results of operations.

Additionally, if any of such risks or similar accidents occur, we could incur substantial losses as a result of injury or loss of life, severe damage or destruction of property, natural resources and equipment, regulatory investigation and penalties and environmental damage and clean-up responsibility. If we experience any of these problems, our ability to conduct operations could be adversely affected. While we maintain insurance coverage that we deem appropriate for these risks, our operations may result in liabilities exceeding such insurance coverage or liabilities not covered by insurance.

Shortages or increases in costs of equipment, services and qualified personnel could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

The demand for qualified and experienced personnel to 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. Additionally, higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. Shortages of field personnel and equipment or price increases could significantly affect our ability to execute our exploration and development plans as projected.

Competition in the oil and natural gas industry is intense, which may adversely affect our ability to succeed.

The oil and natural gas industry is intensely competitive, and we compete with many companies that have greater financial and other resources than we do. Many of these companies not only explore for and produce oil and natural gas, but also conduct 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 identify, 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 competitors may be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than we can, which would adversely affect our competitive position.

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

A significant aspect of our exploration and development plan involves seismic data. Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are present in those structures. Other geologists and petroleum professionals, when studying the same seismic data, may have significantly different interpretations than our professionals. Our drilling activities may not be geologically successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area may not improve as a result of using 2-D and 3-D seismic data.

The use of 2-D and 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses due to such expenditures. In addition, we may often gather 2-D and 3-D seismic data over large areas in order to help us delineate those portions of an area that we believe are desirable for drilling. Therefore, we may choose not to acquire option or lease rights prior to acquiring seismic data, and in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in such location. If we are not able to lease those locations on acceptable terms, we will have made substantial expenditures to acquire and analyze 2-D and 3-D seismic data without having an opportunity to benefit from those expenditures.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our oil and natural gas exploration, production, transportation and treatment operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these laws and regulations. As a result of recent incidents involving the release of oil and natural gas and fluids as a result of drilling activities in the United States, there have been a variety of regulatory initiatives at the federal and state levels to restrict oil and natural gas drilling operations in certain locations. Any increased regulation or suspension of oil and natural gas exploration and production, or revision or reinterpretation of existing laws and regulations, that arises out of these incidents or otherwise could result in delays and higher operating costs. Such costs or significant delays could have a material adverse effect on our business, financial condition and results of operations. We must also comply with laws and regulations prohibiting fraud and market manipulations in energy markets. To the extent we are a shipper on interstate pipelines, we must comply with the FERC-approved tariffs of such pipelines and with federal policies related to the use of interstate capacity.

Laws and regulations governing oil and natural gas exploration and production may also affect production levels. We are required to comply with federal and state laws and regulations governing conservation matters, including provisions related to the unitization or pooling of our oil and natural gas properties; the establishment of maximum rates of production from wells; the spacing of wells; and the plugging and abandonment of wells. These and other laws and regulations can limit the amount of oil and natural gas we can produce from our wells, limit the number of wells we can drill, or limit the locations at which we can conduct drilling operations.

New laws or regulations, or changes to existing laws or regulations, may unfavorably impact us, could result in increased operating costs and could have a material adverse effect on our financial condition and results of operations. In addition, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) and rules promulgated thereunder could reduce trading positions in the energy futures or swaps markets and materially reduce hedging opportunities for us, which could adversely affect our revenues and cash flows during periods of low commodity prices, and which could adversely affect our ability to restructure hedges when it might be desirable to do so.

Additionally, state and federal regulatory authorities may expand or alter applicable pipeline safety laws and regulations, compliance with which may increase capital costs for us and third-party downstream oil and natural gas transporters. These and other potential regulations could increase our operating costs, reduce our liquidity, delay our operations, increase direct and third-party post production costs or otherwise alter the way we conduct our business, which could have a material adverse effect on our financial condition, results of operations and cash flows and which could reduce cash received by or available for distribution, including any amounts paid for transportation on downstream interstate pipelines.

Risks and uncertainties related to the adoption and implementation of regulations restricting oil and gas development in Colorado.

We have substantial undeveloped reserves and unproved acreage in the North Park Basin area of Jackson County, Colorado. Recently, various initiatives have been promoted by interest groups in Colorado to increase regulations restricting oil and gas development. For example, on November 6, 2018, Coloradans considered Proposition 112, a ballot initiative that would have established a new statewide minimum distance requirement for new oil and gas development far in excess of existing Colorado Oil and Gas Conservation Commission ("COGCC") setback regulations. Although Coloradans did not approve Proposition 112, future similar initiatives, if implemented, could pose operational challenges, substantially limit our development activity and require higher levels of capital expenditures than we currently anticipate, and therefore have a significant adverse effect on our ability to develop proved undeveloped reserves in the North Park Basin. Such restrictions, additional costs and delays could adversely impact our financial condition, results of operations and/or cash flows.

Should we fail to comply with all applicable statutes, rules, regulations and orders of the FERC, the CFTC, or the FTC, we could be subject to substantial penalties and fines.

Under the EPAct 2005 and implementing regulations, the FERC prohibits market manipulation in connection with the purchase or sale of natural gas. The CFTC has similar authority under the Commodity Exchange Act and regulations it has promulgated thereunder with respect to certain segments of the physical and futures energy commodities market including oil and natural gas. The FTC also prohibits manipulative or fraudulent conduct in the wholesale petroleum market with respect to sales of commodities, including crude oil, condensate and natural gas liquids. These agencies have substantial enforcement authority, including the ability to impose penalties for current violations in excess of $1 million per day for each violation. The FERC has also imposed requirements related to reporting of natural gas sales volumes that may impact the formation of prices indices. Additional rules and legislation pertaining to these and other matters may be considered or adopted from time to time. Our failure to comply with these or other laws and regulations administered by these agencies could subject us to criminal and civil penalties, as described in Item 1. "Business— Other Regulation of the Oil and Natural Gas Industry."

Our operations are subject to environmental and occupational safety and health laws and regulations that could adversely affect the cost, manner or feasibility of conducting operations or result in significant costs and liabilities.

Our oil and natural gas exploration and production operations are subject to stringent and complex federal, state, tribal, regional and local laws and regulations governing worker safety and health, the discharge and disposal of substances into the environment or otherwise relating to environmental protection. Failure to comply with these laws and regulations may result in litigation; the assessment of sanctions, including administrative, civil or criminal penalties; the imposition of investigatory, remedial or corrective action obligations; the occurrence of delays or restrictions in permitting or performance of projects; and the issuance of orders and injunctions limiting or preventing some or all of our operations in affected areas.

Under certain environmental laws and regulations, we could be subject to strict, and/or joint and several liability for the investigation, removal or remediation of previously released materials or property contamination, regardless of whether we were responsible for the release or contamination or whether the operations were in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties upon which our wells are drilled or facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal may also have the right to pursue legal actions to enforce compliance, to seek damages for contamination, for personal injury, natural resources damage or property damage.

Changes in environmental laws and regulations occur frequently, and any changes that result in delays or restrictions in permitting or development of projects or more stringent or costly construction, drilling, water management, or completion activities or waste handling, storage, transport, remediation or disposal, emission or discharge requirements could require significant expenditures by us to attain and maintain compliance and may otherwise have a material adverse effect on our results of operations, competitive position or financial condition.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and additives under pressure into targeted subsurface formations to stimulate oil and natural gas production. We routinely utilize hydraulic fracturing techniques in the majority of our drilling and completion programs. The process is typically regulated by state oil and gas commissions, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA published permitting guidance in February 2014 addressing the use of diesel fuel in fracturing operations; issued CAA final regulations in 2012 and additional CAA regulations in June 2016 governing performance standards for the oil and natural gas industry; and in June 2016 issued final effluent limitations guidelines under the CWA that waste-water from shale natural gas extraction operations must meet before discharging to a publicly-owned treatment plant. The EPA also issued an Advance Notice of Proposed Rulemaking under TSCA in 2014 regarding reporting of the chemical substances and mixtures used in hydraulic fracturing, but, to date, has taken no further action. Separately, the BLM published a final rule in March 2015 that establishes new or more stringent standards for performing hydraulic fracturing on federal and Indian lands. However, the U.S. District Court of Wyoming struck down this rule in June 2016. The June 2016 decision was appealed to the U.S. Circuit Court of Appeals for the Tenth Circuit. Following issuance of a presidential executive order to review rules related to the energy industry, in July 2017, the BLM published a proposed rule to rescind the 2015 final rule. In September 2017, the Tenth Circuit issued a ruling to vacate the Wyoming trial court decision and dismiss the lawsuit challenging the 2015 rule in light of the BLM’s proposed rulemaking. The BLM issued a final rule repealing the 2015 hydraulic fracturing rule in December 2017.

From time to time, the U.S. Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process but, at this time, federal legislation related to hydraulic fracturing appears unlikely. In addition, certain states, including Oklahoma and Colorado, have adopted regulations that could impose new or more stringent permitting, disclosure, and well-construction requirements on hydraulic fracturing operations. If new laws or regulations that significantly restrict or regulate hydraulic fracturing are adopted at the local, state or federal level, fracturing activities with respect to our properties could become subject to additional permit requirements, reporting requirements or operational restrictions, which may result in permitting delays and potential increases in costs. These delays or additional costs could adversely affect the determination of whether a well is commercially viable. Restrictions on hydraulic fracturing could also reduce the amount of oil, natural gas or NGLs that are ultimately produced in commercial quantities from our properties.

Legislation or regulatory initiatives intended to address seismic activity are restricting and could restrict our ability to dispose of saltwater produced alongside our hydrocarbons, which could limit our ability to produce oil and natural gas economically and have a material adverse effect on our business.
Large volumes of saltwater produced alongside our oil, natural gas and NGLs in connection with drilling and production operations are disposed of pursuant to permits issued 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.

Evaluation of seismic incidents and whether or to what extent those events are induced by the injection of saltwater into disposal wells continues to evolve, as governmental authorities consider new and/or past seismic incidents in areas where salt 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 saltwater generated by production and development activities, whether by plugging back the depths of disposal wells, reducing the volume of salt water disposed in such wells, restricting disposal well locations or otherwise, or by requiring us to shut down disposal wells, which could negatively affect the economic lives of our properties.

Refer to “—Environmental Regulations— Subsurface Injections” included in Item 1 of this report for additional discussion of the current and potential impacts of legislation or regulatory initiatives related to seismic activity on our operations.

Climate change laws and regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas that we produce.
The EPA previously published its findings that emissions of GHGs present a danger to public health and the environment because such gases are, according to the EPA, contributing to warming of the Earth’s atmosphere and

other climatic changes. Based on these findings, the EPA has adopted various rules to address GHG emissions under existing provisions of the CAA. For example, the EPA has adopted rules requiring the reporting of GHG emissions from various oil and natural gas operations on an annual basis, which includes certain of our operations. In addition, in June 2016, the EPA finalized rules to reduce methane emissions from new, modified or reconstructed sources in the oil and natural gas sector, including implementation of an LDAR program to minimize methane emissions, under the CAA's New Source Performance Standards Quad Oa. However, over the past year the EPA has taken several steps to delay implementation of the Quad Oa standards, and the agency proposed a rulemaking in June 2017 to stay the requirements for a period of two years and in October 2018, the EPA proposed revisions to Quad Oa, such as changes to the frequency for monitoring fugitive emissions at well sites and changes to requirements that a professional engineer certify when meeting certain Quad Oa requirements is technically infeasible. Regardless of the stay and potential regulatory revisions, it is possible that these rules will continue to require oil and gas operators to expend material sums.

In addition, in November 2016, the BLM issued final rules to reduce methane emissions from venting, flaring, and leaks during oil and gas operations on public lands that are substantially similar to the EPA Quad Oa requirements. However, on December 8, 2017, the BLM published a final rule to temporarily suspend or delay certain requirements contained in the November 2016 final rule until January 17, 2019, including those requirements relating to venting, flaring and leakage from oil and gas production activities. Further, in September 2018, the BLM published a final rule to revise or rescind certain provisions of the 2016 rule. While, as a result of these developments, future implementation of the EPA and BLM methane rules is uncertain, given the long-term trend towards increasing regulation, future federal GHG regulations of the oil and gas industry remain a possibility. Moreover, several states where we operate, including Colorado, have already adopted rules requiring operators of both new and existing sources to develop and implement LDAR program and install devices on certain equipment to capture 95% of methane emissions.

Compliance with these rules could require us to purchase pollution control equipment, optical gas imaging equipment for LDAR inspections, and to hire additional personnel to assist with inspection and reporting requirements.

In addition, there are a number of state and regional efforts that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs 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 was one of almost 200 nations that agreed in December 2015 to the Paris Agreement. However, the Paris Agreement did not impose any binding obligations on the United States. Moreover, in June 2017, President Trump stated that the United States would withdraw from the Paris Agreement but may enter into a future international agreement related to GHGs. In August 2017, the U.S. State Department officially informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. Such withdrawal has not yet been finalized, and whether the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time. Further, several states and local governments remain committed to the principles of the Paris Agreement in their effectuation of policy and regulations. It is not possible at this time to predict how or when the United States might impose restrictions on GHGs as a result of the international climate change agreement.

The adoption and implementation of any laws or regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur additional costs to monitor, report and potentially reduce emissions of GHGs associated with its operations or could adversely affect demand for the oil and natural gas that we produce, and thus possibly have a material adverse effect on our revenues, as well as having the potential effect of lowering the value of our reserves. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel 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, to the extent increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that could have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events, such events could have a material adverse effect on our assets and operations, and potentially subject us to greater regulation.

Risks and uncertainties related to the potential sale or lease of our corporate headquarters.
Our corporate headquarters building in downtown Oklahoma City, OK, is substantially underutilized. We have entered into a brokerage agreement to seek to lease the unutilized portion of the building. We may seek and/or receive offers to purchase the entire building in the future. Any alternative we pursue is subject to certain risks and uncertainties, including, among other things, the possibility that any alternative we select will not be completed on

terms that are advantageous to us and the likelihood that an outright sale of our corporate headquarters will be at a sales price significantly below its current carrying value on our books.

Repercussions from terrorist activities or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts or other armed conflict involving the United States or its interests abroad may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If events of this nature occur and persist, the attendant political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on prevailing oil and natural gas prices and causing a reduction in our revenues. Oil and natural gas production facilities, transportation systems and storage facilities could be direct targets of terrorist attacks, and/or operations could be adversely impacted if infrastructure integral to our operations is destroyed by such an attack. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Our failure to maintain an adequate system of internal control over financial reporting, could adversely affect our ability to accurately report our results.

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with generally accepted accounting principles. A material weakness is a deficiency, or a combination of deficiencies, in our internal control over financial reporting that results in a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. Effective internal controls are necessary for us to provide reliable financial reports and deter and detect any material fraud. If we cannot provide reliable financial reports or prevent material fraud, our reputation and operating results would be harmed. We maintained effective internal control over financial reporting as of December 31, 2018, as further described in Part II "Item 9A—Controls and Procedures" and "Management's Report on Internal Control over Financial Reporting." Our efforts to develop and maintain our internal controls and to remediate material weaknesses in our controls may not be successful, and we may be unable to maintain adequate controls over our financial processes and reporting in the future, including future compliance with the obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to develop or maintain effective controls, or difficulties encountered in their implementation, including those related to acquired businesses, or other effective improvement of our internal controls could harm our operating results. Ineffective internal controls could also cause investors to lose confidence in our reported financial information.

Our derivative activities could result in financial losses and are subject to new derivatives legislation and regulation which could adversely affect our ability to hedge risks associated with our business.

We may enter into financial derivative instruments with respect to a portion of our production to manage our exposure to oil, gas, and NGL price volatility. To the extent that we engage in price risk management activities to protect ourselves from commodity price declines, we would be prevented from fully realizing the benefits of commodity price increases above the prices established by our hedging contracts. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which the contract counterparties fail to perform under the contracts. Further, to date, we have not designated and do not currently plan to designate any of our derivative contracts as hedges for accounting purposes and, as a result, record all derivative contracts on our balance sheet at fair value with changes in fair value recognized in current period earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative contracts.

The Dodd-Frank Act created a new regulatory framework for oversight of derivatives transactions by the CFTC and the SEC. Among other things, the Dodd-Frank Act subjects certain swap participants to new capital, margin and business conduct standards. In addition, the Dodd-Frank Act contemplates that where appropriate in light of outstanding exposures, trading liquidity and other factors, swaps (broadly defined to include most hedging instruments other than futures) will be required to be cleared through a registered clearing facility and traded on a designated exchange or swap execution facility, unless the "end-user" exception from clearing applies. The Dodd-Frank Act also established a new Energy and Environmental Markets Advisory Committee to make recommendations to the CFTC regarding matters of concern to exchanges, firms, end users and regulators with respect to energy and environmental markets and also expands the CFTC's power to impose position limits on specific categories of swaps (excluding swaps entered into for *bona fide* hedging purposes).

There are some exceptions to these requirements for entities that use swaps to hedge or mitigate commercial risk. However, although we may qualify for exceptions, our derivatives counterparties may be subject to new capital, margin and business conduct requirements imposed as a result of the Dodd-Frank Act, which may increase our transaction costs or make it more difficult for us to enter into hedging transactions on favorable terms.

The full impact of the Dodd-Frank Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter and reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and gas.

Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations. In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations. At this time, the impact of such regulations is not clear.

The future of the CFTC's rulemaking remains uncertain under the current presidential administration. Recent rule proposals by the CFTC suggest that final consideration of major proposed rules will be made by the current administration. During the last quarter of 2016, the CFTC decided to re-propose, rather than finalize, certain regulations, including (a) limitations on speculative futures and swap positions, (b) regulations on automated trading algorithms and (c) limitations on swap capital requirements for swap dealers and major swap participants. It is also uncertain whether the current Chairman of the CFTC and other CFTC staff will remain with the CFTC under the current presidential administration. If finalized, the position limits rule may have an impact on our ability to hedge our exposure to certain enumerated commodities.

Cyber-attacks or other failures in telecommunications or IT systems could result in information theft, data corruption and significant disruption of our business operations.

In recent years, we have increasingly relied on information technology systems and networks in connection with our business activities, including certain of our exploration, development and production activities. We rely on digital technology, including information systems and related infrastructure, as well as cloud applications and services, to, among other things, estimate quantities of oil and natural gas reserves, analyze seismic and drilling information, process and record financial and operating data and communicate with employees and third parties. As dependence on digital technologies has increased, cyber incidents, including deliberate attacks and attempts to gain unauthorized access to computer systems and networks, have increased in frequency and sophistication. These threats pose a risk to the security of our systems and networks, the confidentiality, availability and integrity of our data and the physical security of our employees and assets. We have experienced, and expect to continue to confront, attempts from hackers and other third parties to gain unauthorized access to our information technology systems and networks. Although prior cyber-attacks have not had a material adverse impact on our operations or financial performance, there can be no assurance that we will be successful in preventing cyber-attacks or successfully mitigating their effect. Any cyber-attack could have a material adverse effect on our reputation, competitive position, business, financial condition and results of operations. Cyber-attacks or security breaches also could result in litigation or regulatory action, as well as significant additional expense to implement further data protection measures.

In addition to the risks presented to our systems and networks, cyber-attacks affecting oil and natural gas distribution systems maintained by third parties, or the networks and infrastructure on which they rely, could delay or prevent delivery of our production to markets. A cyber-attack of this nature would be outside our control, but could have a material, adverse effect on our business, financial condition and results of operations.

We have programs, processes and technologies in place to attempt to prevent, detect, contain, respond to and mitigate security-related threats and potential incidents. We undertake ongoing improvements to our systems, connected devices and information-sharing products in order to minimize vulnerabilities, in accordance with industry and regulatory standards; however, because the techniques used to obtain unauthorized access change frequently and can be difficult to detect and anticipating, identifying or preventing these intrusions or mitigating them if and when they occur is challenging and makes us more vulnerable to cyber-attacks than other companies not similarly situated.

If our security measures are circumvented, proprietary information may be misappropriated, our operations may be disrupted, and our computers or those of our customers or other third parties may be damaged. Compromises of our security may result in an interruption of operations, violation of applicable privacy and other laws, significant legal and financial exposure, damage to our reputation, and a loss of confidence in our security measures.

Risks Relating to Our Emergence from Bankruptcy

Our historical financial information may not be indicative of future financial performance.

Our capital structure was significantly impacted by the Plan. Under fresh-start reporting rules that applied to us upon the Emergence Date, assets and liabilities were adjusted to fair values and our accumulated deficit was restated to zero. Accordingly, because fresh-start reporting rules applied, our financial condition and results of operations following emergence from Chapter 11 will not be comparable to the financial condition and results of operations reflected in our historical financial statements.

Risks Relating to our Common Stock

The exercise of all or any number of outstanding Warrants or the issuance of stock-based awards may dilute your holding of shares of our common stock.
As of the date of filing this report, we have outstanding Warrants to purchase approximately 6.6 million shares of our common stock at average exercise prices of either $41.34 and $42.03 per share. In addition, we have as of the date of this report, 3.0 million shares of common stock reserved for future issuance under the SandRidge Energy, Inc. 2016 Omnibus Incentive Plan (the, “Omnibus Incentive Plan”). The exercise of equity awards, including any stock options that we may grant in the future, the Warrants, and the sale of shares of our common stock underlying any such options or the Warrants, could have an adverse effect on the market for our common stock, including the price that an investor could obtain for their shares. Investors may experience dilution in the net tangible book value of their investment upon the exercise of the Warrants and any stock options that may be granted or issued pursuant to the Omnibus Incentive Plan in the future.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

Information regarding the Company’s properties is included in Item 1.

Item 3. ***Legal Proceedings***

As previously disclosed, on May 16, 2016, the Debtors filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code in the Bankruptcy Court. The Bankruptcy Court confirmed the Plan on September 9, 2016, and the Debtors subsequently emerged from bankruptcy on October 4, 2016.

Pursuant to the Plan, claims against the Company were discharged without recovery in each of the following consolidated cases (the "Cases"):

•In re SandRidge Energy, Inc. Securities Litigation, Case No. 5:12-cv-01341-LRW, USDC, Western District of Oklahoma
•Ivan Nibur, Lawrence Ross, Jase Luna, Matthew Willenbucher, and the Duane & Virginia Lanier Trust v. SandRidge Mississippian Trust I, et al., Case No. 5:15-cv-00634-SLP, USDC, Western District of Oklahoma
•Barton W. Gernandt Jr., et al. v. SandRidge Energy, Inc., Case No. 5:15-cv-00834-D, USDC, Western District of Oklahoma

On November 8, 2018, the court in the Gernandt case granted the defendants’ respective motions to dismiss and dismissed the action with prejudice.

Although the remaining two Cases have not been dismissed against certain former officers and directors who remain defendants in the Cases, the Company remains as a nominal defendant in each of the Cases so that any of the respective plaintiffs may seek to recover proceeds from any applicable insurance policies or proceeds. In each of the Cases, to the extent liability exceeds the amount of available insurance proceeds, the Company may owe indemnity obligations to its former officers and/or directors who remain as defendants in such action. An estimate of reasonably probable losses associated with any of the Cases cannot be made at this time, however the Company believes that any potential liability with respect to the Cases will not be material. The Company has not established any reserves relating to any of the Cases.

In addition to the matters described above, the Company is involved in various lawsuits, claims and proceedings which are being handled and defended by the Company in the ordinary course of business. Pursuant to the terms of the SandRidge Mississippian Trust I and SandRidge Mississippian Trust II, the Company is obligated to indemnify, for as long as the Trusts exist, each Royalty Trust against losses, claims, damages, liabilities and expenses, including reasonable costs of investigation and attorney's fees and expenses arising out of certain legal matters as stipulated in the respective agreements with each Royalty Trust.

Item 4. ***Mine Safety Disclosures***

Not applicable.

PART II

Item 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

PRICE RANGE OF COMMON STOCK

Since October 4, 2016, the Successor Company's common stock has been listed on the New York Stock Exchange ("NYSE") under the symbol "SD." During the period from January 7, 2016 through October 3, 2016, our common stock was quoted for public trading on the Pink Sheets quotations system, an over-the-counter market, under the symbol "SDOCQ.PK." The over-the-counter market quotations reflect inter-dealer prices, without retail mark-up, mark-down or commission and may not necessarily represent actual transactions. Prior to January 7, 2016, the Predecessor Company's common stock was also listed on the NYSE under the symbol "SD."

On February 20, 2019, there were 312 record holders of the Company's common stock.

We have neither declared nor paid any cash dividends on either the Predecessor or the Successor Company's respective common stock, and we do not anticipate declaring any dividends in the foreseeable future. We expect to retain cash for the operation and expansion of our business, including exploration, development and production activities. In addition, the terms of the Successor Company's indebtedness restrict our ability to pay dividends. If our dividend policy changes in the future, our ability to pay dividends would be subject to these restrictions and then-existing conditions, including results of operations, financial condition, contractual obligations, capital requirements, business prospects and other factors deemed relevant by the Successor Company's board of directors.

PERFORMANCE GRAPH

The following graph compares the cumulative total return to stockholders on SandRidge common stock relative to the cumulative total returns of the S&P Oil and Gas Exploration and Production Index and the S&P 500 Index from October 4, 2016 through December 31, 2018. The graph assumes that the value of the investment in the Successor Company's common stock and in each of the indexes was $100.00 on October 4, 2016, the date the Successor Company's common stock began trading.

The following graph compares the cumulative total return to stockholders on SandRidge common stock relative to the cumulative total returns of the S&P Oil and Gas Exploration and Production Index and the S&P 500 Index from January 1, 2014 through October 3, 2016. The graph assumes that the value of the investment in the Predecessor Company's common stock and in each of the indexes was $100.00 on January 1, 2014.

The performance graphs above are furnished and not filed for purposes of Section 18 of the Exchange Act and will not be incorporated by reference into any registration statement filed under the Securities Act unless specifically identified therein as being incorporated therein by reference. The performance graphs are not soliciting material subject to Regulation 14A.

ISSUER PURCHASES OF EQUITY SECURITIES

The following table presents a summary of share repurchases made during the three-month period ended December 31, 2018.

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share		Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under the Program (In millions)
October 1, 2018 - October 31, 2018	—	$	—	N/A	N/A
November 1, 2018 - November 30, 2018	578	$	9.76	N/A	N/A
December 1, 2018 - December 31, 2018	4,379	$	8.80	N/A	N/A
Total	4,957			—	

1. Includes shares of common stock tendered by employees in order to satisfy tax withholding requirements upon vesting of their stock awards.

Item 6. ***Selected Financial Data***

The following table sets forth, as of the dates and for the periods indicated, our selected financial information, which is derived from our audited consolidated financial statements for the respective periods. The information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 of this report and our consolidated financial statements and notes thereto contained in "Financial Statements and Supplementary Data" in Item 8 of this report. The following information is not necessarily indicative of future results.

	Successor				**Predecessor**	
	Year Ended December 31,			**Period from October 2, 2016 through December 31,**	**Period from January 1, 2016 through October 1,**	**Year Ended December 31,**
	2018	**2017**		**2016**	**2016**	**2015**	**2014**
Statement of Operations Data **(in thousands, except per share data)**						
Revenues	$ 349,395	$ 357,299	$ 98,456	$ 293,809	$ 768,709	$ 1,558,758
Total operating expenses(1)	359,770	317,668	434,801	1,200,012	5,411,387	968,534
(Loss) income from operations	(10,375)	39,631	(336,345)	(906,203)	(4,642,678)	590,224
Other (expense) income						
Interest expense	(2,787)	(3,868)	(372)	(126,099)	(321,421)	(244,109)
Gain on extinguishment of debt	1,151	—	—	41,179	641,131	—
Gain on reorganization items, net	—	—	—	2,430,599	—	—
Other income, net	2,865	2,550	2,744	1,332	2,040	3,490
Total other income (expense)	1,229	(1,318)	2,372	2,347,011	321,750	(240,619)
(Loss) income before income taxes	(9,146)	38,313	(333,973)	1,440,808	(4,320,928)	349,605

Income tax (benefit) expense	(71)	(8,749)	9	11	123	(2,293)
Net (loss) income	(9,075)	47,062	(333,982)	1,440,797	(4,321,051)	351,898
Less: net (loss) income attributable to noncontrolling interest(2)	—	—	—	—	(623,506)	98,613
Net (loss) income attributable to SandRidge Energy, Inc.	(9,075)	47,062	(333,982)	1,440,797		