SANDRIDGE ENERGY INC
Form 10-K
March 03, 2017

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, 2016
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 and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted 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 and post 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. ¨

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

Large accelerated filer o	Accelerated filer o
Non-accelerated filer þ (Do not check if smaller reporting company)	Smaller reporting company 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 30, 2016 was approximately $13.3 million based on the closing price as quoted on the Pink Sheets. As of February 24, 2017, there were 35,872,778 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company's definitive proxy statement for the 2017 Annual Meeting of Stockholders are incorporated by reference in Part III.

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Certain Defined 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. In addition, this report includes terms commonly used in the oil and natural gas industry, which are defined in the "Glossary of Oil and Natural Gas Terms" beginning on page 23.

Cautionary Note Regarding Forward-Looking Statements

Various statements contained in this report, including those that express a belief, expectation, or intention, as well as those that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These statements generally are accompanied by words that convey projected future events or outcomes. These forward-looking statements may include projections and estimates concerning the Company's capital expenditures, liquidity, capital resources and debt profile, pending dispositions, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, elements of the Company's business strategy, compliance with governmental regulation of the oil and natural gas industry, including environmental regulations, acquisitions and divestitures and the effects thereof on the Company's financial condition and other statements concerning the Company's 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 uncertainty of future events or outcomes. The Company has based these forward-looking statements on its current expectations and assumptions about future events. These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions and expected future developments as well as other factors the Company believes are appropriate under the circumstances. The actual results or developments anticipated may not be realized or, even if substantially realized, may not have the expected consequences to or effects on the Company's business or results. Such statements are not guarantees of future performance and actual results or developments may differ materially from those projected in such forward-looking statements. These forward-looking statements speak only as of the date hereof. The Company disclaims any obligation to update or revise these forward-looking statements unless required by law, and it cautions readers not to rely on them unduly. While the Company's management considers 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, including the following:

- risks associated with drilling oil and natural gas wells;
- the volatility of oil, natural gas and natural gas liquids ("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 its 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;
- 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;
- 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; and
- the need to maintain adequate internal control over financial reporting.

PART I

Item 1. Business

GENERAL

SandRidge Energy, Inc. is an oil and natural gas company with a principal focus on exploration and production activities in the Mid-Continent and Rockies regions of the United States. The Company's Rockies properties were acquired during the fourth quarter of 2015.

As of December 31, 2016, the Company had 3,122 gross (2,310.0 net) producing wells, a substantial portion of which it operates, and approximately 1,364,000 gross (950,000 net) total acres under lease. As of December 31, 2016, the Company had one rig drilling in the Mid-Continent. Total estimated proved reserves as of December 31, 2016 were 163.9 MMBoe, of which approximately 74% were proved developed.

The Company's principal executive offices are located at 123 Robert S. Kerr Avenue, Oklahoma City, Oklahoma 73102 and the Company's telephone number is (405) 429-5500. SandRidge makes available free of charge on its website at www.sandridgeenergy.com its annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports as soon as reasonably practicable after the Company electronically files such material with, or furnishes it to, the Securities and Exchange Commission ("SEC"). Any materials that the Company has filed with the SEC may be read and copied at the SEC's Public Reference Room at 100 F Street, N.E., Room 1580, Washington D.C. 20549 or accessed via the SEC's website address at www.sec.gov. The public may also obtain information about the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330.

Reorganization Under Chapter 11 and Emergence from Bankruptcy

On May 16, 2016, the Company and certain of its direct and indirect subsidiaries (collectively, the "Debtors") filed voluntary petitions (the "Bankruptcy Petitions") for reorganization under Chapter 11 of the United States Bankruptcy Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court"). The Bankruptcy Court confirmed the Debtors' joint plan of reorganization on September 9, 2016 (as amended, the "Plan"), and the Debtors' subsequently emerged from bankruptcy on October 4, 2016 (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 - Fresh Start Accounting" to the accompanying consolidated financial statements contained in Item 8, "Financial Statements and Supplementary Data."

The reorganization under Chapter 11 substantially reduced indebtedness and restructured the Company's balance sheet. Throughout the course of the Chapter 11 reorganization, we were able to conduct normal business activities and pay associated obligations for the period following the bankruptcy filing and paid certain pre-petition obligations, including employee wages and benefits, goods and services provided by certain vendors, transportation of our production, and royalties and costs incurred on the Company's behalf by other working interest owners. As a result of the reorganization, we now have an improved capital structure and enhanced financial flexibility.

Fresh Start Accounting

The Company elected to apply fresh start accounting effective October 1, 2016, to coincide with the timing of its normal fourth quarter reporting period, which resulted in SandRidge becoming a new entity for financial reporting purposes. The Company evaluated and concluded that events between October 1, 2016 and October 4, 2016 were immaterial and use of an accounting convenience date of October 1, 2016 was appropriate. As such, fresh start accounting is reflected in the accompanying consolidated balance sheet as of December 31, 2016 and related fresh start adjustments are included in the accompanying statement of operations for the period from January 1, 2016 through October 1, 2016 (the “Predecessor 2016 Period”).

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 (the “Successor 2016 Period”) will not be 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.

Board of Directors

Pursuant to the Plan of Reorganization confirmed by the Bankruptcy Court, the post-emergence board of directors is comprised of five directors, including the Company's Chief Executive Officer, James Bennett, and four non-employee directors, Michael L. Bennett, John V. Genova, William "Bill" M. Griffin, Jr. and David J. Kornder.

Presentation of Royalty Trust Activities

Information presented for the years ended December 31, 2015 and 2014 includes 100% of the interests and activities of the SandRidge Mississippian Trust I (the "Mississippian Trust I"), the SandRidge Permian Trust (the "Permian Trust") and the SandRidge Mississippian Trust II (the "Mississippian Trust II") (collectively, the "Royalty Trusts"), including amounts attributable to noncontrolling interest. On January 1, 2016, we adopted the provisions of ASU 2015-02, "Amendments to the Consolidation Analysis," which led to the conclusion that the Royalty Trusts were no longer variable interest entities ("VIEs"), and a cumulative-effect adjustment was made to equity to remove the effect of any previously recorded non-controlling interest. Prior periods were not restated. For the 2016 periods, we have proportionately consolidated only our share of each Royalty Trust's assets, liabilities, revenues and expenses.

Post-Emergence Business Strategy

SandRidge's mission is to create resource value from its oil and natural gas development and production activities in the Mid-Continent and Rockies regions of the United States. In pursuit of its mission, the Company focuses on the following strategies:

Complementary Operating Areas. Our primary areas of operation are the Mid-Continent area of Oklahoma and Kansas and the Niobrara Shale in the Colorado Rockies. In the Mid-Continent, we are able to (i) leverage technical expertise in the interpretation of geological and operational opportunities, (ii) take advantage of investments in infrastructure including electrical infrastructure and saltwater gathering and disposal systems and (iii) opportunistically grow our holdings through acquisitions, farmouts and operations in this area to achieve production and reserve growth. We are developing a proven oil resource play on our Rockies acreage similar to that being developed by industry in Colorado's DJ Basin, as both areas draw from the oil rich Niobrara Shale. We will continue to apply our core competencies in developing medium depth formations in the Rockies by deploying our expertise in multi-stage fracture stimulation, artificial lift and extended and multi-lateral horizontal wellbore designs. Additionally, as operator of a majority of our wells, we can further apply competitive advantages to deliver strong, sustainable returns.

Preservation of Capital in Depressed Commodity Pricing Environment. During periods of depressed oil and natural gas pricing, such as that which began during the second half of 2014 and continued throughout 2015 and 2016, we have implemented measures to preserve capital and liquidity by decreasing capital expenditures and focusing drilling efforts on locations that make the most effective use of existing infrastructure, and which have a greater certainty of economic returns. We have established a range for our 2017 capital expenditures budget between $210.0 million and $220.0 million, with the substantial majority of the budgeted expenditures being designated for exploration and production activities.

Focus on Cost Efficiency and Capital Allocation. By leveraging our experienced workforce, scalable operational structure and infrastructure systems, we are able to achieve cost efficiencies and sustainable returns in the Mid-Continent and Rockies areas. In the Mid-Continent, we focus on lower-risk, high rate of return and repeatable drilling opportunities with long economic lives. This has resulted in improved economic returns associated with our multi-lateral wellbore designs, completion designs, well site production facilities, pad drilling utilization, vendor contracts and spud-to-spud cycle time, which reduced our cost structure in the Mid-Continent. Further, due to the relatively low pressure and shallow characteristics of the reservoirs we develop, we are able to maintain a low-cost operating structure and manage service costs. We believe similar opportunities also exist in the Rockies, and have been able to utilize certain technologies and experience from our Mid-Continent operations in the development of our Rockies acreage. The ability to drill multiple laterals or extended laterals from a single pad or single vertical wellbore is facilitating the cost-effective development of this oil rich resource play.

Mitigate Commodity Price Risk. As appropriate, we enter into derivative contracts to mitigate a portion of the commodity price volatility inherent in the oil and natural gas industry. This increases the predictability of cash inflows for a portion of future production, lessens funding risks for longer term development plans, and locks in rates of return on our capital projects.

Maintain Flexibility. We have multi-year inventories of both oil and natural gas drilling locations within our core operating areas, which allows management to efficiently direct capital toward projects with the most attractive returns.

Pursue Opportunistic Acquisitions. We periodically review acquisition targets to complement our existing asset base. Targets are selectively identified based on several factors including relative value, hydrocarbon mix and location, and the relative fit of our core competencies and technical expertise and, when appropriate, seek to acquire them at a discount to other capital allocation opportunities.

Acquisitions and Divestitures

2016 Divestiture and Release from Treating Agreement

On January 21, 2016, we transferred ownership of substantially all of our oil and natural gas properties and midstream assets located in the Piñon field in the West Texas Overthrust (“WTO”) and $11.0 million in cash to a wholly owned subsidiary of Occidental Petroleum Corporation (“Occidental”) and were released from all past, current and future claims and obligations under an existing 30-year treating agreement with Occidental.

The assets of Piñon Gathering Company, LLC (“PGC”), which we acquired in October 2015 as discussed further below, were included in the consideration conveyed to Occidental.

2015 Acquisitions

Piñon Gathering Company, LLC. In October 2015, we acquired the assets of and terminated a gas gathering agreement with PGC for $48.0 million in cash and $78.0 million principal amount of newly issued 8.75% Senior Secured Notes due 2020 (“PGC Senior Secured Notes”). PGC owned approximately 370 miles of gathering lines supporting the natural gas production from the Company's Piñon field in the WTO.

Rockies Properties - North Park Basin. In December 2015, we acquired approximately 135,000 net acres in the North Park Basin, Jackson County, Colorado for approximately $191.1 million in cash, including post-closing adjustments. Also included in the acquisition were working interests in 16 wells previously drilled on the acreage. Additionally, the seller paid us $3.1 million for certain overriding interests retained in the properties.

2014 Divestiture

Sale of Gulf of Mexico and Gulf Coast Properties. On February 25, 2014, we sold certain subsidiaries that owned our Gulf of Mexico and Gulf Coast oil and natural gas properties (collectively, the “Gulf Properties”), to Fieldwood Energy, LLC (“Fieldwood”) for $702.6 million, net of working capital adjustments and post-closing adjustments, and Fieldwood’s assumption of approximately $366.0 million of related asset retirement obligations. We used the proceeds from the sale to fund drilling in the Mid-Continent.

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, 2016, unless otherwise noted

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	127.8	42.2	8.3	1,185,408	793,471	$ 105.6
Rockies	30.2	1.4	59.1	140,216	132,504	87.4
Other	5.9	1.6	10.1	38,785	23,909	—
Total	163.9	45.2	9.9	1,364,409	949,884	$ 193.0

(1) Average daily net production for the month of December 2016.
(2) Estimated net proved reserves as of December 31, 2016 divided by production for the month of December 2016 annualized.
(3) Capital expenditures for the year ended December 31, 2016 on an accrual basis.

Properties

Mid-Continent

We held interests in approximately 1,185,000 gross (793,000 net) leasehold acres located primarily in Oklahoma and Kansas at December 31, 2016. Associated proved reserves at December 31, 2016 totaled 127.8 MMBoe, 87% of which were proved developed reserves, based on estimates prepared by Cawley, Gillespie & Associates, Inc., ("CG&A") and our internal engineers. Our interests in the Mid-Continent as of December 31, 2016 included 1,972 gross (1,179.5 net) producing wells with an average working interest of 60%. We had one rig operating in the Mid-Continent as of December 31, 2016, which was drilling a horizontal well. We drilled a total of 16 wells in this area during 2016, all of which were horizontal wells.

Mississippian Formation. The Mississippian formation is an expansive carbonate hydrocarbon system located on the Anadarko Shelf in northern Oklahoma and southern Kansas, and is a key 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 lies stratigraphically between various formations of Pennsylvanian age and the Devonian-aged Woodford Shale formation. The Mississippian formation can reach 1,000 feet in gross thickness and have targeted porosity zone(s) ranging between 20 and 150 feet in thickness. At December 31, 2016, we had approximately 1,087,000 gross (736,000 net) acres under lease and 1,471 gross (917.6 net) producing wells in the Mississippian formation.

Other Formations. The Meramec formation, the primary target in the STACK play of Blaine and Kingfisher Counties, is currently being drilled using horizontal well technology in Garfield, Major, Dewey, and Woodward Counties, a play area called the NW STACK. The formation is Mississippian in age, lying above the Osage formation and below Chester (if present) and Pennsylvanian formations. It is composed of interbedded shales, sands, and carbonates. The top of the formation ranges from about 5,800 feet at the northern edge of the basin to greater than 14,000 feet toward the interior of the basin. The thickness of the formation ranges from about 50 feet to over 400 feet across the STACK and NW STACK area. We drilled two wells in this formation during 2016. Of our total Mississippian acreage at December 31, 2016, approximately 105,500 gross (54,100 net) acres were under lease in the Meramec formation.

The Osage formation, also a target in the STACK and NW STACK plays, has been targeted both vertically and horizontally across the Anadarko Basin, with the Sooner Trend being a notable historic play. The formation is Mississippian in age, lying above the Woodford formation and below the Meramec and Pennsylvanian formations. It is composed of low porosity, fractured limestone and chert. The top of the formation ranges from 6,000 feet at the northern edge of the basin to about 12,300 feet toward the interior of the basin, with formation thickness ranging from about 450 to 1,400 feet. We drilled one well in this formation during 2016. Of our total Mississippian acreage at December 31, 2016, approximately 13,200 gross (7,600 net) acres were under lease in the Osage formation.

The Woodford Shale is the primary hydrocarbon source for both the Meramec and Osage, while 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.

Rockies

Our Rockies properties consisted of approximately 140,000 gross (133,000 net) acres, and 25 gross (25.0 net) producing wells with an average working interest of 100%, at December 31, 2016. Associated proved reserves at December 31, 2016 were approximately 30.2 MMBoe, of which approximately 12.1% were proved developed reserves. The Rockies acreage is located within the Niobrara Shale play. The Niobrara Shale is characterized by numerous stacked pay reservoirs at depths of 5,500 to 9,000 feet with reservoir thickness over 450 feet. We drilled a total of 10 horizontal producing wells in this area during 2016.

Other properties

Our other oil and natural gas properties include properties in the Permian Basin. As of December 31, 2016, our other properties consisted of approximately 39,000 gross (24,000 net) leasehold acres, 1,125 gross (1,105.5 net) producing wells with an average working interest of 98%. Associated proved reserves at December 31, 2016 were 5.9 MMBoe, 100% of which were proved developed reserves. We did not drill any wells in this area during 2016.

Proved Reserves

Preparation of Reserves Estimates

The estimates of oil, natural gas and NGL reserves in this report are based on reserve reports, which were largely prepared by independent petroleum engineers. To achieve reasonable certainty, the Company's reservoir engineers relied on technologies that have been demonstrated to yield results with consistency and repeatability. 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 petroleum engineers. Such consultation included review of properties, assumptions and any new data available. The Corporate Reservoir department's internal reserves estimates and methodologies were compared to those prepared by independent petroleum engineers to test the reserves estimates and conclusions before the reserves estimates 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 such as the future price of oil and natural gas; 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 the Company's 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 reservoir engineers continually monitor well performance, making reserves estimate adjustments, as necessary, to ensure the most current information is reflected in reserves estimates. This information used to prepare reserve estimates includes production histories as well as other geologic, economic, ownership and engineering data. The Corporate Reservoir department currently has a total of nine full-time employees, comprised of five degreed engineers and four 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, internal controls within the reserve estimation process include

- the Corporate Reservoir Department follows comprehensive SEC-compliant internal policies to determine and report proved reserves including:
- confirming that reserves estimates include all properties owned and are based upon proper working and net revenue interests;
- reviewing and using data provided by other departments within the Company such as Accounting in the estimation process;
- communicating, collaborating, analytical engineering with technical personnel of our business units;
- comparing and reconciling the internally generated reserves estimates to those prepared by third parties.
- reserves estimates are prepared by experienced reservoir engineers or under their direct supervision; and
- no employee's compensation is 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 a committee of executives, and subsequently obtains approval of all 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 Reservoir Department works closely with its 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 the Company's total proved reserves prepared by each of the independent petroleum consultants is shown in the table below.

	December 31,		
	2016	2015	2014
Cawley, Gillespie & Associates, Inc.	72.0%	77.7%	82.4%
Ryder Scott Company, L.P.	18.4%	8.5 %	— %
Netherland, Sewell & Associates, Inc.	3.6 %	3.9 %	3.7 %
Total	94.0%	90.1%	86.1%

The remaining 6.0%, 9.9% and 13.9% of the estimated proved reserves as of December 31, 2016, 2015 and 2014, respectively, were based on internally prepared estimates.

Copies of the reports issued by our independent petroleum consultants with respect to the Company's oil, natural gas and NGL reserves for the substantial majority of all geographic locations as of December 31, 2016 are filed with this report as Exhibits 99.1, 99.2 and 99.3. The geographic location of the Company's estimated proved reserves prepared by each of the independent petroleum consultants as of December 31, 2016 is presented below.

	Geographic Locations—by Area by State
Cawley, Gillespie & Associates, Inc.	Mid-Continent—KS, OK
Ryder Scott Company, L.P.	Rockies—CO
Netherland, Sewell & Associates, Inc.	Permian Basin—TX

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 consulting petroleum engineering since 2013 and over 15 years of prior industry experience;
- licensed professional engineers in the state of Texas; and
- Bachelor of Science Degree in Chemical Engineering

Technologies

Under SEC rules, proved reserves are 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, based on prices used to estimate reserves, from a given date forward from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. The term “reasonable certainty” implies a high degree of confidence that the quantities of oil, natural gas and/or NGLs actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

The area of a reservoir considered proved includes (i) the area 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.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves that can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir, or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. In determining the amount of proved reserves, the price used must be the average price during the 12-month period prior to the ending date of the period covered by the reserve report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, 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.

The estimates of proved developed reserves included in the reserve report were prepared using decline curve analysis to determine the reserves of individual producing wells. After estimating the reserves of each proved developed well, it was determined that a reasonable level of certainty exists with respect to the reserves that can be expected from close offset undeveloped wells in the field.

Reporting of Natural Gas Liquids

NGLs are produced as a result of the processing of a portion of our natural gas production stream. At December 31, 2016, NGLs comprised approximately 21% 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 separate 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. 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, 2016, 2015 and 2014, the substantial majority of which were prepared by independent petroleum engineers. The PV-10 values shown in the table below are not intended to represent the current market value of estimated proved reserves as of the dates shown. The reserve reports were based on the Company's drilling schedule at the time year end reserve reports were prepared. Reserves for 2016 include our proportionate share of the reserves attributable to the Royalty Trusts while 2015 and 2014 include 100% of the reserves attributable to the Royalty Trusts. Our year end 2016 PUD development plan established that 100% of our current proved undeveloped reserves will be developed by the end of 2021. See "Critical Accounting Policies and Estimates" in Item 7 of this report for further discussion of uncertainties inherent to the reserves estimates.

	December 31,		
	2016	2015	2014
Estimated Proved Reserves(1)			
Developed			
Oil (MMBbls)	25.9	48.6	79.0
NGL (MMBbls)	29.3	51.1	56.8
Natural gas (Bcf)	393.0	964.6	1,203.4
Total proved developed (MMBoe)	120.7	260.5	336.4
Undeveloped			
Oil (MMBbls)	27.0	29.3	47.0
NGL (MMBbls)	4.2	9.9	35.0
Natural gas (Bcf)	71.8	149.2	584.8
Total proved undeveloped (MMBoe)	43.2	64.1	179.5
Total Proved			
Oil (MMBbls)	52.9	77.9	126.0
NGL (MMBbls)	33.5	61.0	91.8
Natural gas (Bcf)	464.8	1,113.8	1,788.2
Total proved (MMBoe)(2)	163.9	324.6	515.9
Standardized Measure of Discounted Net Cash Flows (in millions)(2)(3)	$438.4	$1,315.0	$5,516.4
PV-10 (in millions)(4)	$438.4	$1,314.6	$4,087.8

(1) Estimated proved reserves and the future net revenues, PV-10 and Standardized Measure were determined using a 12-month unweighted average of the first-day-of-the-month index price for each month of each year, and do not reflect actual prices at December 31, 2016 or current 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 Company's 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, 2016	$39.25	$ 2.48	$38.59	$10.99	$ 1.56
December 31, 2015	$46.79	$ 2.59	$45.29	$12.68	$ 1.87
December 31, 2014	$91.48	$ 4.35	$91.65	$32.79	$ 3.61

(a)

Index prices are based on average West Texas Intermediate posted 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) Estimated total proved reserves and Standardized Measure attributable to noncontrolling interest for the years ended December 31, 2015 and 2014 are shown in the table below.

	Estimated Proved Reserves (MMBoe)	Standardized Measure (In millions)
December 31, 2015	19.1	$ 224.6
December 31, 2014	27.6	$ 643.3

See “Note 22—Supplemental Information on Oil and Natural Gas Producing Activities” to the consolidated financial statements in Item 8 of this report for additional information regarding reserve and Standardized Measure amounts attributable to noncontrolling interests.

(3) Standardized Measure represents the present value of estimated future cash inflows from proved oil, natural gas and NGL reserves, less future development and production costs, and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions used to calculate PV-10. Standardized Measure differs from PV-10 as Standardized Measure includes the effect of future income taxes. At December 31, 2016, the present value of future income tax discounted at 10% was insignificant due to an excess of tax basis in the full cost pool over projected undiscounted future cash flows.

(4) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil, natural gas and NGL reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash flows and using 12-month average prices for the years ended December 31, 2016, 2015 and 2014. PV-10 differs from Standardized Measure because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of fair market value of the Company’s 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,		
	2016	2015	2014
	(In millions)		
Standardized Measure of Discounted Net Cash Flows	$438.4	$1,314.6	$4,087.8
Present value of future income tax discounted at 10%	—	0.4	1,428.6
PV-10	$438.4	$1,315.0	$5,516.4

Proved Reserves - Mid-Continent. Proved reserves in the Mid-Continent, primarily the Mississippian formation, decreased from 259.1 MMBoe at December 31, 2015 to 127.8 MMBoe at December 31, 2016. Net of production, the overall decrease of 113.2 MMBoe is primarily due to downward revisions of prior estimates of approximately 106.6 MMBoe, predominantly from revisions of approximately 94.5 MMBoe due to well performance and 12.1 MMBoe due to pricing. The negative revisions from well performance resulted from steeper than anticipated well production decline rates for Mississippian horizontal wells in areas with increased natural fracture density and that have been developed with three or more horizontal wells per section as inter-well pressure communication has had more impact on well performance than originally forecasted. Additionally, changing pressure conditions in the Company’s Mississippian wells producing with artificial lift have resulted in increased production decline rates that are now becoming more predictable on a large group of base wells as this population of wells has been producing for more than two years. Of the total performance revisions, approximately 85% were to gas and associated NGL reserves, with the revisions to gas mostly from changes made to late-life decline rates, and 15% were to oil reserves. The other decrease was 13.0 MMBoe of adjustment due to the proportionate consolidation of the Royalty Trusts’ reserves in 2016 compared to full consolidation in 2015. These decreases were partially offset by 6.5 MMBoe of extensions due to successful drilling.

Proved Reserves - Rockies. Our proved reserves in the Rockies were acquired in December 2015 and increased from 27.6 MMBoe at December 31, 2015 to 30.2 MMBoe at December 31, 2016, primarily due to reserve extensions from horizontal drilling. The acquisition of these reserves in 2015 provided an important proved reserve addition to our asset base. Reservoir characteristics of the Niobrara in the North Park Basin are similar to those of the Niobrara in the DJ Basin to the east of North Park. The Niobrara reservoir consists of multiple stacked benches with the Company's proved reserves primarily booked to only one bench. Proved developed reserves were booked based on 25 horizontal producing wells across the play. Production performance and reservoir data gathered from the producing wells confirm consistency in reservoir properties such as porosity, thickness and stratigraphic conformity. These wells encountered proven Niobrara reserves within multiple benches. Using the performance of the proved developing producing wells, proved undeveloped reserves were booked for only one bench of the Niobrara across 27 sections of the proved development area. Although well density in the DJ Basin Niobrara indicates the potential for greater than four wells per section booking, we have only booked up to four wells per section for the Niobrara.

Proved Reserves - Other. In 2016, proved reserves, net of production, decreased by 31.3 MMBoe, primarily due to the divestiture of 24.6 MMBoe of reserves located in the Piñon field in the WTO and a decrease of 6.1 MMBoe due to the proportionate consolidation of the Royalty Trusts' reserves in 2016 compared to full consolidation in 2015. In 2015, proved reserves decreased by 20.0 MMBoe, primarily due to pricing revisions as a result of significantly lower commodity prices.

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

	Year Ended December 31,		
	2016	2015	2014
Reserves converted from proved undeveloped to proved developed (MMBoe)	6.8	15.8	31.4
Drilling capital expended to convert proved undeveloped reserves to proved developed reserves (in millions)	$64.5	$117.7	$343.6

Total estimated proved undeveloped reserves as of December 31, 2016 were 43.2 MMBoe, a decrease of 20.9 MMBoe from the prior year, due primarily to downward revisions due to lower prices. Reserves added from extensions and discoveries totaled 5.5 MMBoe, 3.2MMBoe in the Mid-Continent as a result of horizontal drilling and 2.3 MMBoe in the Rockies 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 the year ended December 31, 2015, we recognized a decrease in proved undeveloped reserves of 115 MMBoe, primarily due to negative revisions of approximately 147 MMBoe resulting from lower commodity prices. These negative revisions were partially offset by an addition to oil, natural gas and NGL reserves associated with proved undeveloped properties of 48 MMBoe for the year ended December 31, 2015. Reserves added from extensions and discoveries totaled 22 MMBoe, primarily from horizontal drilling in the Mississippian formation in the Mid-Continent, which includes 6 MMBoe of proved undeveloped reserves booked and converted during 2015. Acquisition of the Rockies assets, located in Jackson County, Colorado, in December 2015 added 26 MMBoe of proved undeveloped reserves. Approximately 10 MMBoe of proved undeveloped reserves at December 31, 2014 were converted to proved developed reserves during 2015.

Excluding asset sales, we recognized a net addition to oil, natural gas and NGL reserves associated with proved undeveloped properties of 73 MMBoe for the year ended December 31, 2014. Reserves added from extensions and discoveries totaled 67 MMBoe, primarily from horizontal drilling in the Mississippian formation in the Mid-Continent, which includes 10 MMBoe of proved undeveloped reserves booked and converted during 2014. Net positive revisions of 6 MMBoe were recognized and were comprised of 16 MMBoe in increases from the Mid-Continent primarily from an improved overall Mississippian proved undeveloped type curve, partially offset by negative 10 MMBoe revisions primarily from the removal of Permian Basin proved undeveloped drilling locations not expected to be drilled within a five year period. Approximately 21 MMBoe of proved undeveloped reserves at

December 31, 2013 were converted to proved developed reserves during 2014.

For additional information regarding changes in proved reserves during each of the three years ended December 31, 2016, 2015 and 2014 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 the Company's total proved reserves at each year end are presented in the table below. The Mississippi Lime Horizontal field, contained more than 15% of the Company's total proved reserves at December 31, 2016, 2015 and 2014, and the Niobrara field contained more than 15% of the Company's total proved reserves at December 31, 2016.

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Year Ended December 31, 2016				
Mississippi Lime Horizontal	5,029	4,357	56,894	18,868
Niobrara	500	—	—	500
Year Ended December 31, 2015				
Mississippi Lime Horizontal	8,041	4,785	77,542	25,750
Year Ended December 31, 2014				
Mississippi Lime Horizontal	8,234	3,470	65,839	22,677

Mississippi Lime Horizontal Field. The Mississippi Lime Horizontal Field is located on the Anadarko Shelf in northern Oklahoma and Kansas and produces from the Mississippian formation. The Company's interests in the Mississippi Lime Horizontal Field as of December 31, 2016 included 1,471 gross (917.6 net) producing wells and a 62% average working interest in the producing area.

Niobrara Field. The Niobrara field is located in Colorado and produces from the Niobrara Shale. The Company's interests in the Niobrara Field as of December 31, 2016 included 25 gross (25.0 net) producing wells and a 100% average working interest in the producing area.

Production and Price History

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

	Successor	Predecessor	Combined	Predecessor	
	Period from October 2, 2016 through December 31,	Period from January 1, 2016 through October 1,	Year Ended December 31,	Year Ended December 31,	
	2016	2016	2016	2015	2014
Production data (in thousands)					
Oil (MBbls)	1,214	4,315	5,529	9,600	10,876
NGL (MBbls)	999	3,358	4,357	5,044	3,794
Natural gas (MMcf)	12,771	44,124	56,895	92,105	85,697
Total volumes (MBoe)	4,342	15,027	19,369	29,995	28,953
Average daily total volumes (MBoe/d)	47.7	54.6	52.9	82.2	79.3
Average prices—as reported(1)					
Oil (per Bbl)	$ 47.03	$ 36.85	$ 39.09	$45.83	$89.86
NGL (per Bbl)	$ 14.77	$ 12.67	$ 13.15	$14.36	$33.41

Natural gas (per Mcf)	$ 2.07	$ 1.78	$ 1.84	$2.12	$3.70
Total (per Boe)	$ 22.64	$ 18.63	$ 19.53	$23.59	$49.08

(1) Prices represent actual average prices for the periods presented and do not include effects of derivative transactions.

	Successor Period from October 2, 2016 through December 31,	Predecessor Period from January 1, 2016 through October 1,	Year Ended December 31,	
	2016	2016	2015	2014
Expenses per Boe				
Lease operating expenses				
Transportation(1)	$ —	$1.75	$1.51	$1.23
Processing, treating and gathering	0.02	0.03	0.88	1.16
Other lease operating expenses(2)	5.67	6.71	7.67	9.27
Total lease operating expenses	$ 5.69	$8.49	$10.06	$11.66
Production taxes(3)	$ 0.61	$0.41	$0.51	$1.10
Ad valorem taxes	$ 0.07	$0.14	$0.23	$0.29

(1) The Successor Company transportation costs are presented as a deduction from revenues. See “Note 3 - Summary of Significant Accounting Policies” to the accompanying consolidated financial statements.

(2) The years ended December 31, 2015 and 2014 include $34.9 million and $33.9 million, respectively, for amounts related to shortfalls in meeting annual CO_2 delivery obligations under a CO_2 treating agreement as described under “—2016 Divestiture and Release from Treating Agreement” above.

(3) Net of severance tax refunds.

Productive Wells

The following table sets forth the number of productive wells in which the Company owned a working interest at December 31, 2016. 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 the Company has 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	1,667	1,032.6	305	146.9	1,972	1,179.5
Rockies	25	25.0	—	—	25	25.0
Other	1,125	1,105.5	—	—	1,125	1,105.5
Total	2,817	2,163.1	305	146.9	3,122	2,310.0

Drilling Activity

The following table sets forth information with respect to wells completed during the periods indicated. The information presented 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. Gross wells refer to the total number of wells in which the Company had a working interest and net wells are the sum of fractional working interests owned in gross wells. As of December 31, 2016, we had 2 gross (1.8 net) operated wells drilling, completing or awaiting completion.

	2016				2015				2014			
	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent
Completed Wells												
Development												
Productive	32	100.0 %	27.0	100.0 %	167	100.0 %	117.0	100.0 %	626	97.5 %	482.3	97.4 %
Dry	—	— %	—	— %	—	— %	—	— %	16	2.5 %	13.0	2.6 %
Total	32	100.0 %	27.0	100.0 %	167	100.0 %	117.0	100.0 %	642	100.0 %	495.3	100.0 %
Exploratory												
Productive	—	— %	—	— %	9	100.0 %	7.0	100.0 %	6	60.0 %	4.6	60.5 %
Dry	—	— %	—	— %	—	— %	—	— %	4	40.0 %	3.0	39.5 %
Total	—	— %	—	— %	9	100.0 %	7.0	100.0 %	10	100.0 %	7.6	100.0 %
Total												
Productive	32	100.0 %	27.0	100.0 %	176	100.0 %	124.0	100.0 %	632	96.9 %	486.9	96.8 %
Dry	—	— %	—	— %	—	— %	—	— %	20	3.1 %	16.0	3.2 %
Total	32	100.0 %	27.0	100.0 %	176	100.0 %	124.0	100.0 %	652	100.0 %	502.9	100.0 %

The Company had one third-party rig operating on its Mid-Continent acreage, and no other rigs operating on its other acreage as of December 31, 2016.

Developed and Undeveloped Acreage

The following table sets forth information regarding the Company's developed and undeveloped acreage at December 31, 2016:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Area				
Mid-Continent	629,965	410,000	555,443	383,471
Rockies	16,366	16,412	123,850	116,092
Other	17,944	14,956	20,841	8,953
Total	664,275	441,368	700,134	508,516

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage is established prior to such date, in which event the lease will remain in effect until production has ceased. As of December 31, 2016, the gross and net acres subject to leases in the undeveloped acreage summarized in the above table are set to expire as follows:

	Acres Expiring	
	Gross	Net
Twelve Months Ending		
December 31, 2017	428,349	315,326
December 31, 2018	68,783	43,906
December 31, 2019	37,473	24,505
December 31, 2020 and later	8,161	5,776
Other(1)	157,368	119,003
Total	700,134	508,516

(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, 2017, includes approximately 369,227 gross (269,130 net) acres in the Mid-Continent area and 48,548 gross (46,099 net) acres in the Rockies area. Of the total 2017 expiring acreage, we anticipate 194,096 gross (130,288 net) acres in the Mid-Continent and 37,925 gross (37,925 net) acres in the Rockies will not be extended or held by production. Approximately 86% of the expiring acreage falls outside of the Company's core development areas. The core development areas include the NW STACK, the Rockies, and high-graded portions of the Mississippian formation.

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 two customers that individually accounted for more than 10% of our total revenue during the Successor 2016 Period and the Predecessor 2016 Period. See "Note 3—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 for our production makes it unlikely that the loss of a single customer in the areas in which we sell our production 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 an initial preliminary review of the title to our properties which do not have proved reserves. Prior to commencing drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects. We are typically responsible for curing any title defects at our expense. In addition, prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and depending on the materiality of properties, 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

The Company competes 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. The Company believes that its leasehold acreage position, geographic concentration of operations and technical and operational capabilities enable it 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 oil and natural gas decreases during the summer months and increases during the winter months. Certain natural gas users utilize natural gas storage facilities and purchase 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 its operating areas. These seasonal anomalies can pose challenges for meeting our well drilling objectives, can delay the installation of production facilities, and can 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 materials into the environment, environmental protection, and natural resources. Numerous governmental entities, including the U.S. Environmental Protection Agency (“EPA”) and analogous state and local agencies, (and, in some cases, private individuals) have the power to enforce compliance with these laws and regulations and the permits issued under them. These laws and regulations may, among other things: (i) require permits to conduct exploration, drilling, water withdrawal and other production 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 affect 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 the Company 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 treatment and disposal or release of hazardous substances, hydrocarbons, and wastes were not under our control. These properties and the substances or wastes disposed 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 solid wastes under RCRA and, instead, are regulated under RCRA’s less stringent non-hazardous solid 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 EPA’s alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and natural gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and natural gas wastes or to sign a determination that revision of the regulations is not necessary. 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

Clean Air Act, 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 is required to make attainment and non-attainment designations for specific geographic locations under the revised standards by October 1, 2017. 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. In June 2016, the EPA also issued final rules that require the reduction of volatile organic compound and methane emissions from additional new, modified or reconstructed oil and natural gas emissions sources. 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 as well as state waters. 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 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 to waters of the United States and state waters 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, but this rule has been stayed nationwide by the U.S. Sixth Circuit Court of Appeals as that appellate court and numerous district courts consider lawsuits opposing implementation of the rule. To the extent the rule expands the scope of the CWA's jurisdiction, we could incur increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. 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. Additionally, some states have considered laws mandating the recycling of flowback and produced water. 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 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, on February 16, 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. On March 7, 2016, the OCC reduced the injection volume of additional Arbuckle disposal wells, including wells we operate. Following earthquakes in August, September and November, the OCC and EPA further limited the disposal volumes that can be disposed in Arbuckle wells, although these recent actions did not cover our disposal wells.

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 identified five areas of heightened seismic concern in Harper and Sumner Counties and created a timeframe over which the maximum of 8,000 barrels of saltwater injection daily into each well. 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 released in March 2015.

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 has published its findings that emissions of carbon dioxide ("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, and blowdowns of natural gas transmission pipelines. The EPA has also adopted regulations that seek to reduce GHG emissions from certain sources. For example, in June 2016, the EPA finalized rules to reduce methane emissions from new, modified or reconstructed sources in the oil and natural gas sector. 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. Future implementation of the BLM rule is uncertain. However, both the EPA and BLM methane rules impose leak detection and repair ("LDAR") requirements. 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 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 and future participation in the Paris Agreement is uncertain. 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 us to incur additional costs 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. 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. 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. 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. On February 11, 2016, the U.S. Fish and Wildlife Service published a final policy which alters how it identifies critical habitat for endangered and threatened species. 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, as a result of a settlement approved by the U.S. District Court for the District of Columbia in 2011, the U.S. Fish and Wildlife Service (the “FWS”) is required to consider listing numerous species as endangered under the ESA by the end of the agency’s 2017 fiscal year.

The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have 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 EPA 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 that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided 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 believe we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

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.

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; issued in June 2016 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; and issued in 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the BLM published a final rule in March 2015 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 ruling is currently on appeal before the U.S. Tenth Circuit Court of Appeals.

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. At the state level, some states, including Oklahoma, have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, disclosure, 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 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.

In July 2014, the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") released the details of a comprehensive rulemaking proposal to improve the safe transportation of large quantities of flammable materials by rail, particularly crude oil and ethanol. The Federal Railroad Administration and PHMSA jointly published the final rule on May 1, 2015, and it became effective July 7, 2015. The final rule (i) contains a new enhanced tank car standard and a risk-based retrofitting schedule for older tank cars carrying crude oil and ethanol; (ii) requires a new braking standard for certain trains; (iii) designates new operational protocols for trains transporting large volumes of flammable liquids, such as routing requirements, speed restrictions, and information for local government agencies; and (iv) provides new sampling and testing requirements to improve classification of energy products placed into transport.

Sales of oil, natural gas and NGLs are 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 NGLs 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 United States Army Corps of Engineers and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration.

Natural Gas Sales and Transportation

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 million 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.

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. Today, 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, we cannot guarantee that the less stringent regulatory approach currently pursued by FERC and Congress will continue indefinitely into the future nor can we 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.

EMPLOYEES

We completed reductions in force during the first and fourth quarters of 2016, and as of December 31, 2016, had 509 full-time employees, including 110 geologists, geophysicists, petroleum engineers, technicians, land and regulatory professionals. Of our 509 employees, 278 were located at the Company’s headquarters in Oklahoma City, Oklahoma at December 31, 2016, and the remaining employees worked in our various field offices and drilling sites.

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a description of the meanings of certain oil and natural gas industry 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.

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 thin, 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 2016 of $39.25/Bbl for oil and $2.48/Mcf for natural gas, the ratio of economic value of oil to gas was approximately 16 to 1, even though the ratio for determining energy equivalency is 6 to 1.
Boe/d. Boe per day.
Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.
Completion. The process of treating a drilled well 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.
CO_2. Carbon dioxide.
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 and to 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 and equip 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.
Environmental Assessment ("EA"). A study to determine whether an action significantly affects the environment, which federal or state agencies may be required by the National Environmental Policy Act or similar state statutes to undertake prior to the commencement of activities that would constitute federal or state actions, such as permitting oil and natural gas exploration and production activities.
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.
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 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.
Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

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.
Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells, as the case may be.
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.
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.
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. Has the meaning given to such term in Rule 4-10(a)(22) of Regulation S-X, which defines proved reserves as:
Those quantities of oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for 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.
The area of a reservoir considered proved includes (i) the area 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 or gas 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.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir, or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

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 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.

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.

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 recompletion.

(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.

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.

Item 1A. Risk Factors

The Chapter 11 proceedings may have disrupted our business and may have materially and adversely affected our operations.
We have attempted to minimize the adverse effect of our Chapter 11 reorganization on our relationships with our employees, suppliers, customers and other parties. Nonetheless, our relationships with our customers, suppliers, certain liquidity providers and employees may have been adversely impacted and our operations, currently and going forward, could be materially and adversely affected.

Our actual financial results after emergence from bankruptcy may not be comparable to our historical financial information as a result of the implementation of the Plan of Reorganization and the transactions contemplated thereby and our adoption of fresh start accounting.
In connection with the disclosure statement we filed with the Bankruptcy Court, and the hearing to consider confirmation of the Plan, we prepared projected financial information to demonstrate to the Bankruptcy Court the feasibility of the Plan and our ability to continue operations upon our emergence from bankruptcy. Those projections were prepared solely for the purpose of the bankruptcy proceedings and have not been, and will not be, updated on an ongoing basis and should not be relied upon by investors. At the time they were prepared, the projections reflected numerous assumptions concerning our anticipated future performance and with respect to prevailing and anticipated market and economic conditions that were and remain beyond our control and that may not materialize. Projections are inherently subject to substantial and numerous uncertainties and to a wide variety of significant business, economic and competitive risks and the assumptions underlying the projections and/or valuation estimates may prove to be wrong in material respects. Actual results will likely vary significantly from those contemplated by the projections. As a result, investors should not rely on these projections.

In addition, upon our emergence from bankruptcy, we adopted fresh-start accounting effective on October 1, 2016 in accordance with ASC Topic 852, “Reorganizations.” Accordingly, our future financial conditions and results of operations may not be comparable to the financial condition or results of operations reflected in our historical financial statements. The lack of comparable historical financial information may discourage investors from purchasing our common stock.

Our historical financial information may not be indicative of future financial performance.
Our capital structure was significantly impacted by the Plan of Reorganization. Under fresh-start reporting rules that apply 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 apply, 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.

Upon our emergence from bankruptcy, the composition of our board of directors changed significantly, and the transition to a new board of directors will be critical to our success.
Pursuant to the Plan, the composition of our board of directors changed significantly. Currently, the board of directors is made up of five directors, only one of which previously served on our board of directors. The new directors have different backgrounds, experiences and perspectives from those individuals who previously served on the board of directors and, thus, may have different views on the issues that will determine the future of the Company. As a result, our future strategy and plans may differ materially from those of the past.

Additionally, the ability of our new directors to quickly expand their knowledge of our business plans, operations and strategies and our technologies will be critical to their ability to make informed decisions about our strategy and operations, particularly given the competitive environment in which our business operates. If our board of directors is not sufficiently informed to make such decisions, our ability to compete effectively and profitably could be adversely affected.

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 (as defined in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Overview") to purchase approximately 6.4 million shares of our common stock. In addition, we have as of the date of this report, 3.2 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.

We do not expect to pay dividends in the near future.
We do not anticipate that cash dividends or other distributions will be paid with respect to our common stock in the foreseeable future. In addition, restrictive covenants in certain debt instruments to which we are, or may be, a party, may limit our ability to pay dividends or for us to receive dividends from our operating companies, any of which may negatively impact the trading price of our common stock.

The ability to attract and retain key personnel is critical to the success of our business and may be affected by our emergence from bankruptcy.
The success of our business depends on key personnel. The ability to attract and retain these key personnel may be difficult in light of our emergence from bankruptcy, the uncertainties currently facing the business and changes we may make to the organizational structure to adjust to changing circumstances. 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.

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 for hydraulic fracturing operations;
- equipment malfunctions, failures or accidents;
- lack of available gathering facilities or delays in construction of gathering 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;

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- 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 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.

Oil, natural gas and NGL prices can fluctuate widely due to a number of factors that are beyond our control. Continued depressed or further declining 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 realizes from the sale of oil, natural gas and NGLs. The markets for these commodities are very volatile and experienced significant decline during the latter half of 2014, and remained depressed throughout 2015 and 2016. Oil, natural gas and NGL prices 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.

For oil, from January 2012 through December 2016, the highest month end NYMEX settled price was $107.65 per Bbl and the lowest was $33.62 per Bbl. For natural gas, from January 2012 through December 2016, the highest month end NYMEX settled price was $5.56 per MMBtu and the lowest was $1.71 per MMBtu. In addition, the market price of oil and natural gas is generally higher in the winter months than during other months of the year due to increased demand for oil and natural gas for heating purposes during the winter season.

Oil prices dropped sharply during the latter half of 2014 and remained at lower levels throughout 2015 and 2016, settling as low as $26.21 per Bbl in February 2016. If a buildup in inventories, lower global demand, or other factors cause prices for U.S. oil, natural gas and NGLs to weaken, our cash flows and revenues may be negatively affected, and we also may ultimately reduce the amount of oil, natural gas and NGLs we can produce economically, causing us to make substantial downward adjustments to its estimated proved reserves and having a material adverse effect on our financial condition and results of operations.

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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 its cash flow and income, are highly dependent on our success in efficiently developing and exploiting its current 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.

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

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

Our acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. 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 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. 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.

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 most recent 12-month average prices for oil and natural gas, adjusted for the impact of derivatives accounted for as cash flow hedges. The Successor Company and Predecessor Company incurred full cost ceiling impairment charges of $319.1 million and $657.4 million for the Successor 2016 Period and the Predecessor 2016 Period, respectively, and the Predecessor Company had cumulative full cost ceiling impairment charges of $8.8 billion and $8.2 billion at October 1, 2016 and December 31, 2015, respectively. We

incurred full cost ceiling impairment charges of $4.5 billion and $164.8 million for the years ended December 31, 2015, and 2014, respectively. If oil, natural gas and NGL 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 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 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. Commodity prices have remained depressed and have at times trended lower. Accordingly, if we had prepared our December 31, 2016 reserve reports based on the updated 12-month average index prices (which were $42.50 and $2.66 through February 1, 2017) instead of the 12-month average index prices (which were $39.25 and $2.48), and without regard to additions or other further revisions to reserves other than as a result of such pricing changes, the PV-10 value of our internally estimated proved reserves would have increased. 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 its 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 2016, we completed a total of 32 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, 2016, approximately 26.4% 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, 2016, approximately 78.0% of our proved reserves and approximately 93.6% 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.

Our development and exploration operations require substantial capital, and 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 from operations was $65.6 million for the Successor 2016 Period and had cash flow used in operations was $112.1 million for the Predecessor 2016 Period. Cash flow from operations was $373.5 million and $621.1 million, for the years ended December 31, 2015 and 2014, respectively. However, as a result of sustained depressed commodity prices, 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. If the debt and equity capital markets do not improve, 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.

Reductions in our revenues and cash flow from operations, whether as a result of lower oil, natural gas and NGL prices, lower production, declines in reserves or for any other reason, may limit our ability to obtain the capital necessary to sustain its operations at desired levels. In order to fund capital expenditures, we may seek additional financing.

Disruptions in the global financial and capital markets also could 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.

The agreements governing our existing indebtedness have restrictions, financial covenants and borrowing base redeterminations, which could adversely affect our operations.
The agreements governing our senior credit facility dated February 10, 2017, (the “refinanced 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 refinanced credit facility also requires us to comply with certain financial covenants and ratios. See additional discussion of the refinanced credit facility under “Cash Flows-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 refinanced credit facility. Our failure to comply with any of the restrictions and covenants under the refinanced 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 refinanced 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 refinanced 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 refinanced credit facility is incurred. If any future indebtedness under our refinanced credit facility were to be accelerated, our assets may not be sufficient to repay such indebtedness in full.

The Bankruptcy Court's order confirming the Plan is subject to a pending appeal.
Parties have appealed the Bankruptcy Court's decision confirming the Plan. Specifically, on September 23, 2016, an informal group of our former shareholders appealed the Bankruptcy Court's entry of the Amended Order Confirming the Amended Joint Chapter 11 Plan of Reorganization of SandRidge Energy, Inc. and its Debtor Affiliates (Docket No. 901). We cannot predict with certainty the ultimate outcome of such appeal. An adverse outcome could negatively affect our business, operations, or finances.

Our derivative activities could result in financial losses and reduce earnings.
To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently have entered, and may in the future enter, into derivative contracts for a portion of our future oil and natural gas production, including fixed price swaps, collars and basis swaps. We have not designated and do not 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. Derivative contracts also expose us to the risk of financial loss in some circumstances, including when:

- production is less than expected;
- the counterparty to the derivative contract defaults on its contract obligations; or
- the actual differential between the underlying price in the derivative contract and actual prices received is materially different from that expected.

In addition, these types of derivative contracts can limit the benefit we would receive from increases in the prices for oil and natural gas.

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.

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.

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 for it 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 attempt 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 well as 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 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. For example, Congress has recently considered, and may continue to consider, legislation that, if adopted in its proposed form, would subject companies involved in oil and natural gas exploration and production activities to, among other items, additional regulation of and restrictions on hydraulic fracturing of wells, and the elimination of certain U.S. federal tax preferences available with respect to oil and natural gas exploration and production activities. 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.

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 materials 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. Increased scrutiny of the oil and natural gas industry may occur as a result of the EPA’s FY 2017-2019 National Enforcement Initiatives, through which the EPA will purportedly address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment.

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; issued in June 2016 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; and issued in 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the BLM published a final rule in March 2015 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 ruling is currently on appeal before the U.S. Tenth Circuit Court of Appeals.

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. In addition, certain states, including Oklahoma, 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 Part I, Item 1 of this report for additional discussion of the current and potential impacts of legislation or regulatory initiatives related to seismic activity on the Company.

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 the Company produces.
The EPA has 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. In additon, 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. Future implementation of the BLM rule is uncertain. However, both the EPA and BLM methane rules impose LDAR requirements. 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 is one of almost 200 nations that agreed in December 2015 to the Paris Agreement. However, the Paris Agreement does not impose any binding obligations on the United States and future participation in the Paris Agreement is uncertain. It is not possible at this time to predict how or when the United State might impose restrictions on GHGs as a result of the international agreement agreed to in Paris. 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. 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.

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, 2016, as further described in "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.

Certain U.S. federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated as a result of future legislation.
In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including to certain key U.S. federal income tax provisions currently available to oil and gas companies. Such legislative changes have included, but not been limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Congress could consider, and could include, some or all of these proposals as part of tax reform legislation, to accompany lower federal income tax rates. Moreover, other more general features of tax reform legislation, including changes to cost recovery rules and to the deductibility of interest expense, may be developed that also would change the taxation of oil and gas companies. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. The passage of any legislation as a result of these proposals or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available with respect to oil and gas development, or increase costs, and any such changes could have an adverse effect on the Company's financial position, results of operations and cash flows.

New derivatives legislation and regulation could adversely affect our ability to hedge risks associated with its business.

The Dodd-Frank Act created a new regulatory framework for oversight of derivatives transactions by the Commodity Futures Trading Commission (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 its 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 new presidential administration. Recent rule proposals by the CFTC suggest that final consideration of major proposed rules will be made by the new 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. In December 2016, the Chairman of the CFTC stated that the CFTC decided to re-propose, rather than finalize, the above regulations, in part based on the uncertainty over the next presidential administration. It is also uncertain whether the current Chairman of the CFTC and other CFTC staff will remain with the CFTC under the new presidential administration. The current Chairman's term expires in April 2017, and two seats are currently open for new appointees, leaving the CFTC's future rulemaking unclear.

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.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

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

Item 3. Legal Proceedings

The Plan in the Chapter 11 Cases discharged certain claims, including claims related to litigation proceedings against the Company that arose before the Emergence Date. The Plan generally treated such claims as general unsecured claims that will receive only partial distribution of the amounts of consideration set aside for such claims under the Plan, which consists of cash, shares of New Common Stock and warrants, once their amounts, if any, are finally determined by the Bankruptcy Court or otherwise. The effectiveness of the Plan also resulted in the release of certain claims held by the Company against various parties to the restructuring and related parties, including certain of the Company’s current and former officers and former directors. See “Note 1- Voluntary Reorganization under Chapter 11 Proceedings” to the accompanying consolidated financial statements in Item 8 of this report for further discussion about the Company’s Bankruptcy Petitions and the Chapter 11 Cases.

To the extent that a claim related to a pre-petition proceeding or action is not characterized as a pre-petition general unsecured claim, the Company does not believe that such claim would be material, although the anticipated resolution of any such proceeding or action is inherently unpredictable.

As previously disclosed, on February 4, 2015, the staff of the SEC Enforcement Division in Washington, D.C., notified the Company that it had commenced an informal inquiry concerning the Company’s accounting for, and disclosure of, its CO_2 delivery shortfall penalties under the terms of the Gas Treating and CO_2 Delivery Agreement, dated June 29, 2008, between SandRidge Exploration and Production, LLC, and Oxy USA Inc. Additionally, the Company received a letter from an attorney for a former employee at the Company (the “Former Employee”). In the letter, the attorney alleged, among other things, that the Former Employee had been terminated because he had objected to the levels of oil and gas reserves disclosed by the Company in its public filings. Over 85% of such reserves were calculated by an independent petroleum engineering firm. The Audit Committee of the Company’s pre-emergence Board of Directors retained an independent law firm to review the Former Employee’s allegations and the circumstances of the Former Employee’s termination. In addition, the Company reported the Former Employee’s allegations to the SEC staff, which thereafter issued two subpoenas to the Company relating to the Former Employee’s allegations. Counsel for the Audit Committee responded to both of these subpoenas. During the course of the above inquiries, the SEC issued a subpoena to the Company seeking documents relating to employment-related agreements between the Company and certain employees. The Company cooperated with this inquiry and, after discussion with the staff, the Company sent corrective letters to certain current and former employees who had entered into agreements containing language that may have been inconsistent with SEC rules prohibiting a company from impeding an individual from communicating directly with the SEC about possible securities law violations. The Company also updated its Code of Conduct and other relevant policies.

On June 16, 2016, the SEC filed a proof of claim in the Company’s Chapter 11 Cases in the amount of $1.2 million relating to the SEC staff’s inquiry concerning employment-related agreements. As a result of the SEC’s proof of claim, the Company established a $1.4 million reserve for this matter.

On December 20, 2016, the Company and the SEC settled both the inquiry involving employment-related agreements and the inquiry involving the termination of the Former Employee. Pursuant to the settlement agreement, the Company agreed to pay a fine in the amount of $1.4 million. The fine will be treated as a general unsecured claim under the Plan and, as such, the Company expects to pay approximately $0.1 million to resolve these two inquiries. The Company neither admitted nor denied any violations as part of the settlement agreement. Additionally, the SEC informed the Company that as part of the settlement agreement, the SEC would not be recommending charges against the Company with regard to its pre-petition disclosures of the CO_2 delivery shortfall penalties under the Company’s agreement with Oxy USA Inc., or with regard to the Company’s pre-petition processes and disclosures related to its reserves.

On October 14, 2016, Lisa West and Stormy Hopson filed a class action complaint in the United States District Court for the Western District of Oklahoma against SandRidge Exploration and Production, LLC, among other defendants. In their complaint, plaintiffs assert various tort claims seeking relief for damages allegedly incurred by the plaintiffs and the proposed class for injury to property and for the purchase of insurance policies allegedly needed by the plaintiffs and the proposed class for seismic activity allegedly caused by the defendants' operation of wastewater disposal wells. An estimate of reasonably probable losses associated with this action cannot be made at this time. The Company had not established any reserves relating to this action.

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.

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

From October 4, 2016 through December 31, 2016, the Successor Company’s common stock was 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 was also listed on the NYSE under the symbol “SD.”

The range of high and low sales prices for the Successor Company’s and the Predecessor Company’s respective common stock for the periods indicated, as reported by the NYSE and the Pink Sheets quotations system, is as follows:

	High	Low
2016		
Successor Company		
Fourth Quarter (from October 4, 2016 through December 31, 2016)	$26.85	$15.75
Predecessor Company		
Fourth Quarter (through October 3, 2016)	$0.02	$0.01
Third Quarter	$0.06	$—
Second Quarter	$0.11	$0.01
First Quarter	$0.20	$0.03
2015		
Fourth Quarter	$0.56	$0.17
Third Quarter	$0.90	$0.25
Second Quarter	$2.30	$0.81
First Quarter	$2.53	$1.13

On February 24, 2017, there were 2 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 on our common stock 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 to our common stock holders. If our dividend policy were to change in the future, our ability to pay dividends would be subject to these restrictions and the Company’s 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, 2016. 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, 2012 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, 2012.
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 by the Successor Company during the three-month period ended December 31, 2016.

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, 2016 — October 31, 2016	—	$ —	N/A	N/A
November 1, 2016 — November 30, 2016	—	$ —	N/A	N/A
December 1, 2016 — December 31, 2016	4,647	$ 23.72	N/A	N/A
Total	4,647		—	

(1) Includes shares of common stock tendered by employees in order to satisfy tax withholding requirements upon vesting of their stock awards. Shares withheld are initially recorded as treasury shares, then immediately retired.

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				
	Period from October 2, 2016 through December 31,	Period from January 1, 2016 through October 1,	Year Ended December 31,			
	2016	2016	2015	2014	2013	2012
Statement of Operations Data (in thousands, except per share data)						
Revenues	$98,456	$293,809	$768,709	$1,558,758	$1,983,388	$1,934,642
Total operating expenses(1)	434,801	1,200,012	5,411,387	968,534	2,152,389	1,609,446
(Loss) income from operations	(336,345)	(906,203)	(4,642,678)	590,224	(169,001)	325,196
Other (expense) income						
Interest expense	(372)	(126,099)	(321,421)	(244,109)	(270,234)	(303,349)
Bargain purchase gain	—	—	—	—	—	122,696
Gain (loss) on extinguishment of debt	—	41,179	641,131	—	(82,005)	(3,075)
Reorganization items	—	2,430,599	—	—	—	—
Other income, net	2,744	1,332	2,040	3,490	12,445	4,741
Total other expense	2,372	2,347,011	321,750	(240,619)	(339,794)	(178,987)
(Loss) income before income taxes	(333,973)	1,440,808	(4,320,928)	349,605	(508,795)	146,209
Income tax expense (benefit)	9	11	123	(2,293)	5,684	(100,362)
Net (loss) income	(333,982)	1,440,797	(4,321,051)	351,898	(514,479)	246,571
Less: net (loss) income attributable to noncontrolling interest	—	—	(623,506)	98,613	39,410	105,000