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.

SANDRIDGE ENERGY, INC.
2016 ANNUAL REPORT ON FORM 10-K
TABLE OF CONTENTS

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	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
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.

24

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;

- 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.

30

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
Net (loss) income attributable to SandRidge Energy, Inc.	(333,982)	1,440,797	(3,697,545)	253,285	(553,889)	141,571
Preferred stock dividends	—	16,321	37,950	50,025	55,525	55,525
(Loss applicable) income available to SandRidge Energy, Inc. common stockholders	$(333,982)	$1,424,476	$(3,735,495)	$203,260	$(609,414)	$86,046
(Loss) earnings per share						
Basic	$(17.61)	$2.01	$(7.16)	$0.42	$(1.27)	$0.19
Diluted	$(17.61)	$2.01	$(7.16)	$0.42	$(1.27)	$0.19

(1) Includes full cost ceiling limitation impairments of $319.1 million, $657.4 million, $4.5 billion and $164.8 million for the Successor 2016 Period, the Predecessor 2016 Period and the years ended December 31, 2015 and 2014, respectively. No full cost ceiling limitation impairments were recorded for the years ended December 31, 2013 or 2012.

48

	Successor	Predecessor			
	As of December 31,	As of December 31,			
	2016	2015	2014	2013	2012
Balance Sheet Data (in thousands)					
Cash and cash equivalents	$ 121,231	$435,588	$181,253	$814,663	$309,766
Property, plant and equipment, net	$ 817,932	$2,234,702	$6,215,057	$6,307,675	$8,479,977
Total assets(1)	$ 1,081,392	$2,922,027	$7,211,823	$7,630,307	$9,716,787
Total debt(1)	$ 305,308	$3,562,378	$3,148,034	$3,140,419	$4,227,139
Total stockholders' equity (deficit)	$ 512,917	$(1,187,733)	$3,209,820	$3,175,627	$3,862,455
Total liabilities and stockholders' equity (deficit)	$ 1,081,392	$2,922,027	$7,211,823	$7,630,307	$9,716,787

(1) Reflects the reclassification of certain debt issuance costs from other assets to long-term debt of $69.1 million, $47.4 million, $54.5 million and $73.9 million for the years ended December 31, 2015, 2014, 2013 and 2012, respectively, as a result of the retrospective adoption of ASU 2015-03 on January 1, 2016. See "Note 3 - Accounting Policies and Procedures" included in Item 8 of this report for further discussion.

There have been no cash dividends declared or paid on either the Predecessor or Successor Company's common stock.

Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis is intended to help the reader understand our business, financial condition, results of operations, liquidity and capital resources. This discussion and analysis should be read in conjunction with other sections of this report, including: “Business” in Item 1, “Selected Financial Data” in Item 6 and “Financial Statements and Supplementary Data” in Item 8. Our discussion and analysis includes the following subjects:

- Overview;
- Consolidated Results of Operations;
- Liquidity and Capital Resources;
- Valuation Allowance; and
- Critical Accounting Policies and Estimates.

Overview

Basis of Presentation

In accordance with ASC 852, the reorganization value of the Successor Company was allocated to its individual assets based on their estimated fair values as of the Emergence Date. As a result, the consolidated financial statements of the Predecessor Company are not comparable to those of the Successor Company.

Our reorganization under Chapter 11 did not result in the divestiture of any of our oil and natural gas properties. As a result, certain operating results and key operating performance measures, including those related to production, average oil and natural gas selling prices, revenues and lease operating expenses, were not significantly impacted by the reorganization, and certain of the combined operating results of the Predecessor 2016 Period and the Successor 2016 Period during the year ended December 31, 2016, are still comparable with certain operating results in the prior years presented. Accordingly, we believe that discussing the combined results of operations and cash flows of the Predecessor Company and the Successor Company for the two periods in 2016 is useful when analyzing certain performance measures. For items that are not comparable, we have included additional analysis to supplement the discussion.

The combined results of operations for the year ended December 31, 2016, represent a supplemental pro forma financial measure due to our reorganization and the application of fresh start accounting. The following line items in our consolidated statements of operations for the year and quarter ended December 31, 2016, are not comparable to any prior annual or quarterly periods due to our reorganization and application of fresh-start accounting:

- Depreciation, depletion and amortization
- Accretion of asset retirement obligations
- Impairment
- Interest Expense
- Net (loss) income

Presentation of Royalty Trust Activities. We adopted the provisions of ASU 2015-02 “Amendments to the Consolidation Analysis,” effective January 1, 2016, which resulted in the determination that the Royalty Trusts no longer qualify as VIEs. As a result, the activities of the Royalty Trusts have been proportionately consolidated for the Predecessor 2016 Period and the Successor 2016 Period. Under the proportionate consolidation method, only our share of each Royalty Trust’s asset, liabilities, revenues and expenses are recorded within the appropriate classifications in the accompanying consolidated financial statements. We adopted the provisions of ASU 2015-02 by recording a cumulative-effect adjustment to equity as of January 1, 2016. As such, the financial information presented for the years ended December 31, 2015 and 2014 has not been restated and includes 100% of the activities of the

Royalty Trusts. The portion of each Royalty Trust's activities attributable to third-party ownership interests is presented as noncontrolling interest for the years ended December 31, 2015 and 2014.

Emergence from Voluntary Reorganization Under Chapter 11

In accordance with the Plan, the following significant transactions occurred upon our emergence from Chapter 11:

- First Lien Credit Agreement. All outstanding obligations under the senior secured revolving credit facility (the "senior credit facility") were canceled, and claims under the senior credit facility received their proportionate share of (a) $35.0

million in cash and (b) newly established $425.0 million reserve-based revolving credit facility (the “New First Lien Exit Facility”). The New First Lien Exit Facility was subsequently refinanced in February 2017 as discussed in “Liquidity and Capital Resources.”

- Cash Collateral Account. We deposited $50.0 million of cash in an account controlled by the administrative agent to the New First Lien Exit Facility (the “Cash Collateral Account”) from the Emergence Date until the first borrowing base redetermination in October 2018 (the “Protected Period”); provided that (a) (i) $12.5 million will be released to us upon delivery of an acceptable business plan to the administrative agent, (ii) $12.5 million will be released to us upon achievement for two consecutive quarters of certain milestones set forth in the business plan and (b) to the extent the foregoing amounts are not released to us, up to $25.0 million will be released to us upon meeting a minimum 2.00:1.00 ratio of proved developed producing reserves to aggregate principal loan commitments under the New First Lien Exit Facility at any time after July 4, 2017. The $50.0 million cash collateral account was subsequently released to us in February 2017 in conjunction with the refinancing of the New First Lien Exit Facility as discussed in “Liquidity and Capital Resources.”

- Senior Secured Notes. All outstanding obligations under the Senior Secured Notes were canceled and exchanged for approximately 13.7 million of the 18.9 million shares of the Successor Company’s Common Stock, (the “New Common Stock”) issued at emergence. Additionally, claims under the Senior Secured Notes received approximately $281.8 million principal value of New Convertible Notes, which are mandatorily convertible into approximately 15.0 million shares of New Common Stock upon the first to occur of several triggering events, one of which was the refinancing of the First Lien Exit Facility.

- General Unsecured Claims. The Predecessor Company’s general unsecured claims, including the 8.75% Senior Notes due 2020, 7.5% Senior Notes due 2021, 8.125% Senior Notes due 2022, and 7.5% Senior Notes due 2023 (collectively, the “Senior Unsecured Notes”) and the 8.125% Convertible Senior Notes due 2022 and 7.5% Convertible Senior Notes due 2023 (collectively, the “Convertible Senior Unsecured Notes” and together with the Senior Unsecured Notes, the “Unsecured Notes”), became entitled to receive their proportionate share of (a) approximately $36.7 million in cash, (b) approximately 5.7 million shares of New Common Stock, 5.2 million of which was issued immediately upon emergence, and (c) 4.9 million Series A Warrants and 2.1 million Series B Warrants, with initial exercise prices of $41.34 and $42.03 per share, respectively, which expire on October 4, 2022, (the “Warrants”). Approximately 4.5 million Series A Warrants and 1.9 million Series B Warrants were issued immediately upon emergence.

- New Building Note. A note with a principal amount of $35.0 million ($36.6 million fair value on the Emergence Date), which is secured by first priority mortgages on the Company’s headquarters facility and certain other non-oil and gas real property located in downtown Oklahoma City, Oklahoma (the “New Building Note”) was issued and purchased on the Emergence Date for $26.8 million in cash, net of certain fees and expenses, by certain holders of the Unsecured Senior Notes.

- Preferred and Common Stock. The Predecessor Company’s 7.0% and 8.5% convertible perpetual preferred stock and common stock were canceled and released under the Plan without receiving any recovery on account thereof.

See “Note 1 - Voluntary Reorganization under Chapter 11 Proceedings,” “Note 11 - Debt” and “Note 15 - Equity” to the consolidated financial statements included in Item 8 of this report for additional information on the transactions noted above.

2016 Operational Activities

Operational highlights for 2016 include the following:

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Total production for 2016 was comprised of approximately 28.5% oil, 49.0% natural gas and 22.5% NGLs compared to 32.0% oil, 51.2% natural gas and 16.8% NGLs in 2015.

- Reduced the total rigs drilling to one at December 31, 2016 from four at December 31, 2015.
- Drilled 16 wells in the Mid-Continent and 10 wells in the Rockies in 2016 compared to drilling 161 wells, excluding salt water disposal wells, in the Mid-Continent and no wells in the Rockies in 2015, respectively.
- Discontinued all remaining drilling and oilfield services operations in 2016, and as a result, our drilling and oilfield services operations no longer constituted a reportable segment in 2016.

- Transferred substantially all oil and natural gas properties and midstream assets located in the Piñon field in the WTO and $11.0 million in cash to Occidental in January 2016 in exchange for the release from all past, current and future claims and obligations under an existing 30-year treating agreement between the companies. This resulted in a substantial decrease in our marketing and midstream operations throughout 2016, and accordingly, our midstream and marketing operations no longer constituted a reportable segment at December 31, 2016.

Outlook

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.

Our estimated proved reserve volumes were 163.9 MMBoe at December 31, 2016, based on independent petroleum engineer estimates using the SEC-mandated historical 12-month unweighted average pricing at such date, which were $39.25 per barrel of oil and $2.48 per Mcf of natural gas. Replacing the January 1, 2016 and February 1, 2016 price components with actual January 1, 2017, and February 1, 2017 benchmark commodities prices, the 12-month unweighted average prices would have been $42.50 per barrel of oil and $2.66 per Mcf of natural gas. Holding our December 31, 2016 reserves estimates and other variables constant and applying the 12-month unweighted average prices through February 1, 2017, our internally estimated proved reserves would not decrease further in the first quarter of 2017. If commodity pricing falls short of our current expectations or rebounds to a level supportive of more drilling, we may change our 2017 capital expenditure plans again. However, we do not expect these short term changes to negatively impact our ability to develop all of our December 31, 2016 proved undeveloped locations within a five year time frame. All reserve estimates for periods after December 31, 2016 provided in this Form 10-K were determined by Company reservoir engineers and, accordingly, have not been fully assessed by independent petroleum consultants.

Consolidated Results of Operations

The majority of our consolidated revenues and cash flow are generated from the production and sale of oil, natural gas and NGLs. Our revenues, profitability and future growth depend substantially on prevailing prices received for our production, the quantity of oil, natural gas and NGLs we produce, our ability to find and economically develop and produce our reserves, and changes in the fair value of our commodity derivative contracts. Prices for oil, natural gas and NGLs fluctuate widely and are difficult to predict. To provide information on the general trend in pricing, the average annual NYMEX prices for oil and natural gas for recent years are presented in the table below:

	Year Ended December 31,				
	2016	2015	2014	2013	2012
Oil (per Bbl)	$43.47	$48.75	$92.91	$98.05	$94.15
Natural gas (per Mcf)	$2.55	$2.62	$4.26	$3.73	$2.83

In order to reduce our exposure to price fluctuations, we have historically entered into commodity derivative contracts for a portion of our anticipated future oil and natural gas production as discussed in “Item 7A. Quantitative and Qualitative Disclosures About Market Risk.” Reducing the Company’s exposure to price volatility helps mitigate the risk that we will not have adequate funds available for our capital expenditure programs.

Acquisitions and Divestitures

Divestiture of WTO Properties and Release from Treating Agreement. On January 21, 2016, we paid $11.0 million in cash and transferred ownership of substantially all of our oil and natural gas properties and midstream assets located in the Piñon field in the WTO to Occidental and were released from all past, current and future claims and obligations under an existing 30-year treating agreement with Occidental.

Acquisition of Rockies Properties. In December 2015, we acquired approximately 135,000 net acres in the North Park Basin, Jackson County, Colorado, including working interests in 16 wells previously drilled on the acreage, for approximately $191.1 million in cash, including post-closing adjustments. Additionally, the seller paid us $3.1 million for certain overriding interests retained in the properties. We began developing the acquired acreage in early 2016.

Acquisition of Piñon Gathering Company, LLC. In October 2015, we acquired the assets of and terminated a gas gathering agreement with PGC for $48.0 million cash and $78.0 million principal amount of Senior Secured Notes. PGC’s assets consisted of approximately 370 miles of gathering lines that supported our production in the Piñon field in West Texas. The transaction resulted in the termination of a gas gathering agreement with PGC under which we were required to compensate PGC for any throughput shortfalls below a required minimum volume. The fair value of the consideration we paid, including the discount attributable to the Senior Secured Notes issued, was approximately $98.3 million and was allocated on a relative fair value basis between the assets acquired (approximately $47.3 million) and a loss on the termination of the gathering contract (approximately $51.0 million). These assets were subsequently transferred to Occidental in the divestiture of the WTO properties discussed above.

Gulf of Mexico and Gulf Coast Properties. On February 25, 2014, we sold subsidiaries that owned the Gulf Properties, for approximately $702.6 million, net of working capital adjustments and post-closing adjustments, and the buyer’s assumption of approximately $366.0 million of related asset retirement obligations. We retained a 2% overriding royalty interest in certain exploration prospects. The proceeds from the sale were used to fund our drilling in the Mid-Continent. This transaction did not result in a significant alteration of the relationship between our capitalized costs and proved reserves and, accordingly, the proceeds were recorded as a reduction to the full cost pool with no gain or loss on the sale.

Production, revenues and expenses, including direct operating expenses, depletion, accretion of asset retirement obligations and general and administrative expenses, for the Gulf Properties included in the Company’s results for the year ended December 31, 2014, was as follows:

	Year Ended December 31, 2014(1)
Production (MBoe)	1,321
Revenues (in thousands)	$ 90,920
Expenses (in thousands)	$ 63,674

(1) Includes activity through February 25, 2014, the date of sale.

Oil, Natural Gas and NGL Production and Pricing

Set forth in the table below is production and pricing information for Successor Company and the Predecessor Company for the respective 2016 periods and the years ended December 31, 2016, 2015 and 2014.

	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
Average prices—including impact of derivative contract settlements(2)					
Oil (per Bbl)	$ 54.59	$ 51.05	$ 51.83	$76.80	$94.18
NGL (per Bbl)	$ 14.77	$ 12.67	$ 13.15	$14.36	$33.41
Natural gas (per Mcf)	$ 1.96	$ 1.77	$ 1.81	$2.45	$3.58
Total (per Boe)	$ 24.41	$ 22.70	$ 23.08	$34.51	$50.36

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

(2) Excludes settlements of commodity derivative contracts prior to their contractual maturity, if any.

For a discussion of reserves, PV-10 and reconciliation to Standardized Measure, see "Business— Primary Operations—Proved Reserves" in Item 1 of this report.

The table below presents production by area of operation for the Successor 2016 Period and the Predecessor 2016 Period and the years ended December 31, 2015 and 2014 and illustrates the impact of (i) the continued decrease in capital expenditures and number of new wells drilled in the Mid-Continent, Permian and other regions, (ii) the sale of the Gulf Properties in 2014, and (iii) the acquisition of the Rockies properties in December 2015.

	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

	Production (MBoe)	% of Total Production		Production (MBoe)	% of Total Production		Production (MBoe)	% of Total Production		Production (MBoe)	% of Total Production	
Mid-Continent	4,018	92.5	%	14,119	94.0	%	26,558	88.5	%	23,423	80.9	%
Rockies	180	4.1	%	320	2.1	%	—	—	%	—	—	%
Gulf of Mexico / Gulf Coast	—	—	%	—	—	%	—	—	%	1,321	4.6	%
Permian Basin	144	3.4	%	489	3.3	%	1,567	5.2	%	2,076	7.2	%
Other	—	—	%	99	0.6	%	1,870	6.3	%	2,133	7.3	%
Total	4,342	100.0	%	15,027	100.0	%	29,995	100.0	%	28,953	100.0	%

Revenues

Consolidated revenues for the Successor 2016 Period, the Predecessor 2016 Period, and the years ended December 31, 2016, 2015 and 2014 are presented in the table below (in thousands).

	Successor	Predecessor		Predecessor	
	Period from October 2, 2016 through December 31,	Period from January 1, 2016 through October 1,	Combined Year Ended December 31,	Year Ended December 31,	
	2016	2016	2016	2015	2014
Revenues					
Oil	$ 57,093	$ 159,023	$ 216,116	$ 439,927	$ 977,269
NGL	14,756	42,541	57,297	72,440	126,759
Natural gas	26,458	78,407	104,865	195,067	316,851
Other	149	13,838	13,987	61,275	137,879
Total revenues(1)	$ 98,456	$ 293,809	$ 392,265	$ 768,709	$ 1,558,758

(1) Includes $57.0 million and $150.4 million of revenues attributable to noncontrolling interests in consolidated VIEs, after considering the effects of intercompany eliminations, for the years ended December 31, 2015 and 2014, respectively.

Variances in oil, natural gas and NGL revenues attributable to changes in the average prices received for our production and total production volumes sold for the years ended December 31, 2016 and 2015 are shown in the table below (in thousands):

2014 oil, natural gas and NGL revenues	$ 1,420,879
Change due to production volumes in 2015	(49,143)
Change due to average prices in 2015	(664,302)
2015 oil, natural gas and NGL revenues	707,434
Change due to production volumes in 2016	(270,688)
Change due to average prices in 2016	(58,468)
2016 oil, natural gas and NGL revenues (Supplemental pro forma combined)	$ 378,278

Oil, natural gas and NGL revenues decreased by a combined $329.2 million, or 46.5% for the year ended December 31, 2016 compared to 2015. The decrease is due largely to lower oil and natural gas production, primarily due to natural declines in existing producing wells, the decrease in new wells drilled during 2016 compared to 2015, and the proportionate consolidation of the Royalty Trusts' activities during the 2016 period. The remaining decrease is primarily due to a decline in the average prices received as a result of declining market prices for oil production, and to a lesser extent, natural gas and NGL production. The decline in average prices received also includes the effects of the Successor Company's election to include transportation deductions in revenues for the Successor 2016 Period.

Oil, natural gas and NGL sales decreased by a combined $713.4 million, or 50.2% for the year ended December 31, 2015 compared to 2014, primarily due to a decline in the average prices received for our oil production, and to a lesser extent lower gas and NGL production.

Other revenues primarily include drilling and oilfield services and marketing and midstream sales, which decreased in 2016 compared to 2015 largely due to discontinuing all remaining drilling and oilfield services operations in 2016, and transferring substantially all oil and natural gas properties and midstream assets located in the Piñon field in the WTO to Occidental in January 2016.

Expenses

Consolidated expenses for the Successor 2016 Period, the Predecessor 2016 Period and the years ended December 31, 2016, 2015 and 2014 are presented below.

	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
	(In thousands)				
Expenses					
Production	$24,997	$129,608	$154,605	$308,701	$346,088
Production taxes	2,643	6,107	8,750	15,440	31,731
Depreciation and depletion—oil and natural gas	33,971	86,613	120,584	319,913	434,295
Depreciation and amortization—other	3,922	21,323	25,245	47,382	59,636
Accretion of asset retirement obligations	2,090	4,365	6,455	4,477	9,092
Impairment	319,087	718,194	1,037,281	4,534,689	192,768
General and administrative	9,837	116,091	125,928	137,715	113,991
Employee termination benefits	12,334	18,356	30,690	12,451	8,874
Loss (gain) on derivative contracts	25,652	4,823	30,475	(73,061)	(334,011)
Loss on settlement of contract	—	90,184	90,184	50,976	—
Other operating expenses	268	4,348	4,616	52,704	106,070
Total expenses(1)	$434,801	$1,200,012	$1,634,813	$5,411,387	$968,534

(1) Includes $679.9 million and $51.0 million of expenses attributable to noncontrolling interests in consolidated VIEs, after considering the effects of intercompany eliminations, for the years ended December 31, 2015 and 2014, respectively. The expenses attributable to noncontrolling interest in consolidated VIEs include $655.9 million and $29.9 million of allocated full cost ceiling impairment for the years ended December 31, 2015 and 2014, respectively.

Production expense includes the costs associated with our exploration and production activities, including, but not limited to, lease operating expense and treating costs. Production expenses for 2016 decreased $154.1 million, or 49.9% from 2015. Production costs per Boe decreased to $7.98 per Boe for the 2016 period from $10.29 per Boe in 2015, primarily due to (i) a decrease in well activity due to fewer new wells being brought on production, (ii) termination of the CO_2 delivery agreement with Occidental in the first quarter of 2016, which resulted in CO_2 delivery shortfall penalties of $2.0 million being incurred in the Predecessor 2016 Period compared to penalties of $34.9 million incurred during 2015, and (iii) the presentation of $7.4 million of transportation costs as a reduction from revenues in the Successor 2016 Period versus the Predecessor Company's presentation of these costs as production expenses. The Predecessor 2016 Period includes approximately $26.2 million of transportation costs.

Production expenses for 2015 decreased $37.4 million, or 10.8% from 2014. Production costs per Boe decreased to $10.29 per Boe for the 2015 period from $11.95 per Boe in 2014, primarily as a result of (i) the sale of the Gulf Properties in February 2014, which had higher production costs inherent with offshore operations, and (ii) a decrease in well activity as a result of fewer new wells being brought on production and a reduction in workover activity in 2015 in conjunction with an increase in combined production for the year ended December 31, 2015 compared to

2014.

Production taxes decreased by $6.7 million, or 43.3%, for 2016, compared to 2015, and decreased by $16.3 million, or 51.3%, for 2015, compared to 2014, primarily due to the decrease in oil, natural gas and NGL revenues. Production taxes as a percentage of oil, natural gas and NGL revenue were consistent at approximately 2.3% for 2016, and 2.2% for both 2015 and 2014.

Depreciation and depletion for oil and natural gas properties for the Successor 2016 Period was recorded at an average depreciation and depletion rate of $7.82 per Boe, which reflects an increase in reserve values due to fresh start valuation adjustments recorded for reserves as of October 1, 2016. The average depreciation and depletion rate for the Predecessor 2016 Period of $5.76 per Boe, decreased from a rate of $10.67 per Boe in 2015, primarily due to full cost ceiling impairments recorded in 2016, and the proportionate consolidation of the Royalty Trusts' activities during 2016.

Depreciation and depletion for oil and natural gas properties decreased by $114.4 million for the year ended December 31, 2015, compared to 2014. This decrease largely resulted from a reduction in the average depreciation and depletion rate per Boe to $10.67 for 2015 from $15.00 for 2014, primarily resulting from (i) the sale of the Gulf Properties in February 2014 (ii) full cost ceiling impairments recorded in 2015 and (iii) changes in future production and planned capital expenditures that occurred in conjunction with the year end 2014 budgeting and reserves estimation processes.

Depreciation and depletion for non-oil and gas properties decreased primarily due to (i) the sale of substantially all drilling assets during 2016 and 2015 after discontinuing drilling operations, (ii) the sale of a property located in downtown Oklahoma City, Oklahoma as well as other corporate assets, and (iii) the divestiture of the WTO properties and related assets.

Impairment expense for the Successor 2016 Period and the Predecessor 2016 Period and the years ended December 31, 2016, 2015 and 2014 consisted of the following (in thousands):

	Successor	Predecessor	Combined	Predecessor	
	Period from October 2, 2016 through December 31, 2016	Period from January 1, 2016 through October 1, 2016	Year Ended December 31, 2016	Year Ended December 31, 2015	2014
Impairment					
Full cost pool ceiling limitation	$ 319,087	$ 657,392	$976,479	$4,473,787	$164,779
Drilling assets	—	3,511	3,511	37,646	27,428
Electrical transmission system	—	55,600	55,600	—	—
Midstream assets	—	1,691	1,691	7,148	561
Other	—	—	—	16,108	—
Total impairment	$ 319,087	$ 718,194	$1,037,281	$4,534,689	$192,768

Full cost pool impairment. Upon the application of fresh start accounting, the value of the Successor Company full cost pool was determined based upon forward strip oil and natural gas prices as of the Emergence Date. Because these prices were higher than the 12-month weighted average prices used in the full cost ceiling limitation calculation at December 31, 2016, the Successor Company incurred a ceiling test impairment of $319.1 million.

Full cost pool impairment recorded for the Predecessor Company in 2016 was due to full cost ceiling limitations recognized in each of the first three quarters of 2016. The impairments recorded in 2015 and the first two quarters of 2016 resulted primarily from the significant decrease in oil prices, and to a lesser extent, natural gas prices, that began in the latter half of 2014 and continued throughout 2015 and the first half of 2016. The impairment recorded in the third quarter of 2016 resulted primarily from downward revisions to forecasted reserves due to a decrease in projected Mid-Continent production volumes. The decrease in projected production volumes 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.

Impairment recorded in 2014 was due to a full cost ceiling limitation resulting from the divestiture of the Gulf Properties in the first quarter of 2014 as the present value of future net revenues associated with the Gulf Properties exceeded the associated reduction to the full cost pool.

Drilling asset impairment. Impairments were recorded on certain drilling assets in the years ended December 31, 2016, and 2015 upon determining their future use was limited after discontinuing drilling operations in the Permian region in 2015 and discontinuing all remaining drilling operations in 2016. Impairment in 2014 was to adjust the carrying value of certain drilling assets classified as held for sale to fair value after classifying certain assets as held for sale or determining that the future use of assets held and used was limited.

Electrical transmission system impairment. Impairment in 2016 primarily reflects a write-down of the value of our electrical transmission system due to a decrease in projected Mid-Continent production volumes supporting the system’s usage.

Midstream asset impairment. Impairment recorded on midstream assets in 2016 and 2015 resulted primarily from the write-downs of generators, compressors and various other equipment, due to their limited use.

Other impairment. Impairment recorded on other assets in 2015, includes a $15.4 million impairment on property located in downtown Oklahoma City, Oklahoma to adjust the carrying value of the property to the agreed upon sales price for which it was later sold in 2016.

General and administrative expenses decreased $11.8 million, or 8.6%, for the year ended December 31, 2016 compared to 2015 due primarily to (i) an $8.4 million decrease in net payroll costs, and (ii) a decrease of $5.0 million due to recording a legal settlement in 2015. The remainder of the decrease in general and administrative expenses resulted primarily from a reduction in various other corporate support costs including office costs, travel, employee placement, training, vehicle and technology costs due to reductions in force in the first and fourth quarters of 2016 and corporate cost cutting measures. These reductions were partially offset by an increase of $8.2 million in professional services costs, which primarily related to consulting fees incurred for the restructuring of the Company prior to the Chapter 11 filings and after the Emergence Date.

General and administrative expenses increased $23.7 million, or 20.8%, for the year ended December 31, 2015 compared to 2014 due primarily to (i) an increase of $14.6 million in professional services costs, including legal and consulting fees, (ii) an increase of $5.0 million due to a legal settlement recorded in 2015, and (iii) a $4.0 million increase in net payroll costs, primarily resulting from a decrease in capitalized salary costs.

Employee termination benefits for the year ended December 31, 2016 represent severance costs incurred primarily as a result of (i) reductions in force in the first and fourth quarters of 2016, (ii) severance costs associated with the departure of executive officers and other senior officers and (iii) discontinuing all remaining drilling and oilfield services operations and the majority of all midstream and marketing services operations in the first quarter of 2016.

Employee termination benefits recorded in 2015 represent severance costs incurred primarily as a result of (i) a reduction in force (ii) severance costs associated with the departure of an executive officer and other senior officers and (iii) discontinuing all remaining drilling and oilfield services operations in the Permian region in 2015. Employee termination benefits recorded in 2014 represent severance costs incurred primarily in conjunction with the sale of the Gulf Properties.

We recorded losses on commodity derivative contracts of $25.7 million and $4.8 million for the Successor 2016 Period and the Predecessor 2016 Period, respectively, as reflected in the accompanying consolidated statements of operations, which includes net cash receipts upon settlement of $7.7 million and $72.6 million, respectively. Included in the net receipts for the Predecessor 2016 Period is $17.9 million related to settlements of contracts prior to their contractual maturity (“early settlements”) in the second quarter of 2016, primarily in response to the Chapter 11 Petitions being filed.

We recorded gains on commodity derivative contracts of $73.1 million and $334.0 million for the years ended December 31, 2015 and 2014, respectively, as reflected in consolidated statements of operations included in Item 8 of this report, which includes net cash (receipts) payments upon settlement of $(327.7) million and $32.3 million, respectively. Included in the net cash payments for 2014 are $69.6 million of cash payments related to early settlements primarily as a result of the sale of the Gulf Properties in February 2014.

Our derivative contracts are not designated as accounting hedges and, as a result, gains or losses on commodity derivative contracts are recorded each quarter as a component of operating expenses. Internally, management views the settlement of derivative contracts at contractual maturity as adjustments to the price received for oil and natural gas production to determine “effective prices.” Gains or losses on early settlements and losses related to amendments of contracts are not considered in the calculation of effective prices. In general, cash is received on settlement of contracts due to lower oil and natural gas prices at the time of settlement compared to the contract price for our oil and natural gas price swaps. Cash is paid on settlement of contracts due to higher oil and natural gas prices at the time of settlement compared to the contract price for our oil and natural gas price swaps.

Loss on settlement of contract in the Predecessor 2016 Period consists of a $78.9 million loss resulting from the termination of a gas treating and CO_2 delivery agreement with Occidental, and a loss of $11.2 million recorded for the cease-use of transportation agreements that supported production from the Piñon field.

Loss on settlement of contract in 2015 resulted from the termination of the Company's gas gathering agreement with PGC under which it was required to compensate PGC for any throughput shortfalls below a required minimum volume. See "—Acquisitions and Divestitures" above and see "Note 5—Acquisitions and Divestitures" to the Company's consolidated financial statements in Item 8 of this report for additional discussion of the acquisition of PGC and the PGC gathering agreement.

Other Income (Expense), Taxes and Net (Loss) Income Attributable to Noncontrolling Interest

Other income (expense), taxes and net (loss) income attributable to noncontrolling interest for the Successor 2016 Period and the Predecessor 2016 Period and the years ended December 31, 2015 and 2014 are reflected in the table below (in thousands).

	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
Other income (expense)					
Interest expense	$(372)	$(126,099)	$(126,471)	$(321,421)	$(244,109)
Gain on extinguishment of debt	—	41,179	41,179	641,131	—
Reorganization items	—	2,430,599	2,430,599	—	—
Other income, net	2,744	1,332	4,076	2,040	3,490
Total other income (expense)	2,372	2,347,011	2,349,383	321,750	(240,619)
(Loss) income before income taxes	(333,973)	1,440,808	1,106,835	(4,320,928)	349,605
Income tax expense (benefit)	9	11	20	123	(2,293)
Net (loss) income	(333,982)	1,440,797	1,106,815	(4,321,051)	351,898
Less: net (loss) income attributable to noncontrolling interest	—	—	—	(623,506)	98,613
Net (loss) income attributable to SandRidge Energy, Inc.	$(333,982)	$1,440,797	$1,106,815	$(3,697,545)	$253,285

Interest expense for the Successor Company and Predecessor Company for the respective 2016 periods and the years ended December 31, 2016, 2015 and 2014 consisted of the following (in thousands):

	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
Interest expense					
Interest expense on debt	$ 1,590	$ 123,350	$ 124,940	$ 304,020	$ 254,475
Amortization of debt issuance costs, premium and discounts	(81)	7,730	7,649	15,014	9,954
Write off of debt issuance costs	—	—	—	7,108	—
(Gain) loss on long-term debt derivatives	—	(1,324)	(1,324)	10,377	—
Capitalized interest	—	(2,240)	(2,240)	(14,018)	(19,718)
Total	1,509	127,516	129,025	322,501	244,711
Less: interest income	(1,137)	(1,417)	(2,554)	(1,080)	(602)
Total interest expense	$ 372	$ 126,099	$ 126,471	$ 321,421	$ 244,109

Interest expense in the Successor 2016 Period is comprised of interest expense incurred on the First Lien Exit Facility prior to the payment of the outstanding balance in October 2016 and commitment fees on the undrawn portion of the First Lien Exit Facility and letters of credit.

Total interest expense decreased $195.0 million for the year ended December 31, 2016 compared to 2015, primarily due to (i) ceasing to record interest expense on the Senior Unsecured Notes at the time of the Chapter 11 filings, (ii) the repurchase of Senior Unsecured Notes in 2015, (iii) conversion of Convertible Senior Unsecured Notes into shares of the Predecessor Company's common stock in the second half of 2015 and first quarter of 2016, and (iv), repayment of all amounts outstanding under the First Lien Exit Facility in October 2016. These decreases were partially offset by (i) interest expense and amortization of discount and debt issuance costs associated with the Senior Secured Notes issued in June and October 2015 through the date of the Chapter 11 filings, and (ii) a reduction in the amount of interest capitalized in the 2016 periods, primarily due to a decrease in drilling activity.

Total interest expense increased $77.3 million for the year ended December 31, 2015 compared to 2014, primarily due to interest expense associated with the $1.25 billion in Senior Secured Notes issued in June 2015. This increase was partially offset by a decrease in interest paid on Senior Unsecured Notes that were repurchased or converted into shares of the Predecessor Company's common stock in 2015 as well as the loss recognized due to an increase in the fair value of derivatives embedded in certain of the Company's long-term debt during the year ended December 31, 2015.

We recognized a gain on extinguishment of debt of $41.2 million in the Predecessor 2016 Period, primarily in connection with the exchange of approximately $232.1 million in aggregate principal amount ($77.8 million net of discount and including holders' conversion feature liabilities) of the Convertible Senior Unsecured Notes for approximately 84.4 million shares of the Predecessor Company's common stock during the first quarter of 2016. Further conversions of the Convertible Senior Unsecured Notes were stayed in May 2016 in conjunction with the filing of the Chapter 11 petitions.

We recognized a gain on extinguishment of debt of $641.1 million for the year ended December 31, 2015, primarily in connection with (i) the exchange of $575.0 million in aggregate principal of Senior Unsecured Notes for Convertible Senior Unsecured Notes, (ii) the repurchase of $350.0 million in aggregate principal of Senior Unsecured Notes for approximately $124.5 million in cash, (iii) the exchange of approximately $50.0 million aggregate principal of 7.5% Senior Unsecured Notes due 2021 and 8.125% Senior Unsecured Notes due 2022 for shares of the Company's common stock, and (iv) conversions of Convertible Senior Unsecured Notes into shares of the Company's common stock.

See "Note 11—Long-Term Debt" to the Company's consolidated financial statements in Item 8 of this report for additional discussion of the Company's long-term debt transactions.

Reorganization items in the Predecessor 2016 Period primarily consist of the net gain recorded on the cancellation of Predecessor Company debt upon emergence from Chapter 11. See "Note 2 - Fresh Start Accounting" to the consolidated financial statements included in Item 8 of this Report for further discussion of reorganization items.

Tax expense and the effective tax rate for the Successor 2016 Period and the Predecessor 2016 Period and the year ended December 31, 2015 were low as a result of the valuation allowance against our net deferred tax asset in each period. The Company's income tax benefit of $2.3 million for the year ended December 31, 2014 is primarily related to a reduction in the Company's gross unrecognized tax benefits following a favorable outcome pertaining to the Company's state income tax audits in the amount of $1.3 million as well as a reduction in federal alternative minimum tax ("AMT") associated with the tax year ended December 31, 2014 in the amount of $1.2 million. With respect to the AMT, the Company reduced each of the current tax liability and corresponding deferred tax asset upon finalizing and filing the Company's federal income tax return for the year ended December 31, 2014. As a result of reducing the deferred tax asset, the Company decreased its valuation allowance against its net deferred tax asset by $1.2 million.

Net (loss) income attributable to noncontrolling interest in 2015 and 2014 primarily represents the portion of (loss) income attributable to third-party ownership in the Royalty Trusts, and was significantly impacted by full cost ceiling impairments attributable to noncontrolling interest of $655.9 million in 2015, and $29.9 million in 2014. Revenues for the Royalty Trusts also decreased in 2015 compared to 2014 as a result of a decrease in average prices received for production, natural declines in production and a reduction in the average number of producing wells as uneconomic wells were shut-in due to depressed commodity pricing. Additionally, net gains recorded on the Royalty Trusts' derivative contracts decreased primarily due to the expiration of the Permian Trust's derivative contracts in the first quarter of 2015. The Company fulfilled its drilling obligations to the Mississippian Trust I in the second quarter of 2013, to the Permian Trust in the fourth quarter of 2014 and to the Mississippian Trust II in the first quarter of 2015.

No further wells will be drilled for the Royalty Trusts.

Liquidity and Capital Resources

At December 31, 2016, we had cash and cash equivalents of $121.2 million, approximately $305.3 million in total debt outstanding and $8.6 million in outstanding letters of credit with no amount outstanding under the First Lien Exit Facility. As of December 31, 2016, the First Lien Exit Facility had an available borrowing base of $425.0 million, which was reduced by the $8.6 million in outstanding letters of credit. As of February 24, 2017, the Company's cash, cash equivalents and cash classified as restricted for the payment of general unsecured claims related to the Company's emergence from Chapter 11, were approximately $127.1 million.

Working Capital and Sources and Uses of Cash

Our principal sources of liquidity for 2017 include cash flow from operations, cash on hand and amounts available under our refinanced credit facility, as discussed in "—Credit Facilities" below.

Significant transactions affecting our future liquidity upon emergence from Chapter 11 included the elimination of approximately $3.7 billion in senior notes and related accrued interest, and issuance of the $35.0 million New Building Note, for which interest is expected to be paid in cash beginning in 2017.

Additionally, our working capital surplus decreased to $43.5 million at December 31, 2016 compared to $236.7 million at December 31, 2015, largely due to fluctuations in the timing and amount of collections of receivables and a decrease in accounts payable resulting from a reduction in drilling activity in 2016.

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. Management intends to fund 2017 capital expenditures using cash flow from operations, cash on hand and, if necessary, borrowings under the refinanced credit facility discussed below.

Cash Flows

Our cash flows from operations are substantially dependent on current and future prices for oil and natural gas, which historically have been, and may continue to be, volatile. For example, 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.

If oil or natural gas prices decline from current levels, they could have a material adverse effect on our financial position, results of operations, cash flows and quantities of oil, natural gas and NGL reserves that may be economically produced. This could result in further full cost pool ceiling impairments. Further, if our future capital expenditures are limited or deferred, or we are unsuccessful in developing reserves and adding production through our capital program, the value of our oil and natural gas properties, financial condition and results of operations could be adversely affected.

Cash flows for the Successor 2016 Period, the Predecessor 2016 Period and the years ended December 31, 2016, 2015 and 2014 are presented in the following table and discussed below (in thousands):

	Successor Period from October 2, 2016	Predecessor Period from January 1, 2016 through	Combined Year Ended December	Predecessor Year Ended December 31,	

	through December 31, 2016	October 1, 2016	31, 2016	2015	2014
Cash flows provided by (used in) operating activities	$65,595	$(112,077)	$(46,482)	$373,537	$621,114
Cash flows used in investing activities	(39,835)	(167,690)	(207,525)	(1,039,640)	(857,241)
Cash flows (used in) provided by financing activities	(415,061)	407,551	(7,510)	920,438	(397,283)
Net (decrease) increase in cash and cash equivalents	$(389,301)	$127,784	$(261,517)	$254,335	$(633,410)

Cash Flows from Operating Activities

The $420.0 million reduction in operating cash flows for the year ended December 31, 2016 compared to 2015, is primarily due to a decrease in revenues from oil, natural gas and NGLs, a reduction in proceeds received on settlement of commodity derivative contracts, an increase in professional and other fees paid in connection with the Company's restructuring in 2016, and the reduction in working capital noted above. These were partially offset by a reduction of $190.6 million in cash paid for interest expense and lower production expenses paid in 2016 compared to 2015.

The $247.6 million reduction in operating cash flows for the year ended December 31, 2015 compared to 2014 was also primarily due to a decrease in revenues from oil, natural gas and NGL production, which was partially offset by proceeds received on the settlement of commodity derivative contracts and, to a lesser extent, a reduction in operating expenses during 2015.

Cash Flows from Investing Activities

The Company dedicates and expects to continue to dedicate a substantial portion of its capital expenditure program toward the exploration for and production of oil and natural gas. These capital expenditures are necessary to offset inherent declines in production and proven reserves, which is typical in the capital-intensive oil and natural gas industry.

During the year ended December 31, 2016, cash flows used in investing activities consisted primarily of capital expenditures for our exploration and production operations.

During the year ended December 31, 2015, cash flows used in investing activities largely consisted of capital expenditures, excluding acquisitions, as well as cash paid for the North Park acquisition and the PGC assets acquired. During the year ended December 31, 2014, cash flows used in investing activities resulted from capital expenditures, excluding acquisitions, of approximately $1.6 billion, which were partially offset by proceeds from the sale of assets of $714.5 million, primarily generated by the sale of the Gulf Properties.

Capital Expenditures. The Company's capital expenditures, on an accrual basis, for the Successor 2016 Period, the Predecessor 2016 Period and the years ended December 31, 2016, 2015 and 2014 are summarized below (in thousands):

	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
Capital expenditures					
Exploration and production	$ 38,062	$ 155,627	$ 193,689	$656,022	$1,508,100
Drilling and oilfield services	—	23	23	4,632	18,385
Midstream services	2,901	3,085	5,986	21,556	44,606
Other	83	2,672	2,755	19,405	37,798
Capital expenditures, excluding acquisitions	41,046	161,407	202,453	701,615	1,608,889
Acquisitions	—	1,328	1,328	241,165	18,384
Total	$ 41,046	$ 162,735	$ 203,781	$942,780	$1,627,273

Capital expenditures, excluding acquisitions, decreased significantly for the year ended December 31, 2016 compared to 2015, due to a decrease in drilling activity.

Capital expenditures, excluding acquisitions, also decreased significantly for the year ended December 31, 2015 compared to 2014, primarily due to a decrease in drilling and leasehold expenditures in the Mid-Continent area. The number of drilling rigs operating on the Company’s properties decreased to four rigs at December 31, 2015 from 35 rigs at December 31, 2014, largely in response to the sharp decline in oil prices during 2014. During the year ended December 31, 2014, the Company received payments for drilling carries from Atinum MidCon I, LLC’s (“Atinum”) and Repsol E&P USA, Inc. (“Repsol”) of approximately $205.6 million, which directly offset the Company’s capital expenditures. Both Atinum and Repsol fully funded their drilling carry commitments during 2014.

During the fourth quarter of 2015, the Company acquired (i) all of the assets of PGC for approximately $47.3 million and (ii) approximately 135,000 net acres and 16 existing oil and natural gas wells in the North Park Basin of the Rockies, in Jackson County, Colorado for approximately $191.1 million in cash, including post-closing adjustments. The seller of the North Park Basin properties also paid the Company $3.1 million for certain overriding interests retained in the properties, which slightly offset acquisition expenditures.

Cash Flows from Financing Activities

Cash used in financing activities the year ended December 31, 2016, was insignificant, primarily due to the net effect of borrowings and repayments under the First Lien Exit Facility, as well as proceeds received from the New Building Note, which were subsequently remitted to unsecured creditors on the Emergence Date in accordance with the Plan.

The Company's financing activities provided $920.4 million in cash for the year ended December 31, 2015 compared to using $397.3 million of cash in 2014. The change is due primarily to (i) the issuance of $1.25 billion in Senior Secured Notes in June 2015, which was partially offset by $124.5 million in cash paid for the repurchase of debt, and debt issuance costs incurred of $53.2 million, (ii) a decrease of $55.5 million in noncontrolling interest distributions, and (iii) a decrease of $44.3 million in preferred dividends paid in cash during the 2015 period compared to the 2014 period, and (iv) proceeds from the sale of Royalty Trust units of $22.1 million. These increases were partially offset by a net payment of $111.3 million to repurchase 27.4 million shares of the Company's common stock, and $44.1 million for the early settlement of financing derivatives as a result of the sale of the Gulf Properties.

Indebtedness

Long-term debt consists of the following at December 31, 2016 (in thousands):

First Lien Exit Facility	$—
New Convertible Notes	268,780
New Building Note	36,528
Total debt	$305,308

The Chapter 11 filings constituted an event of default with respect to the Predecessor Company's existing debt obligations, causing the Predecessor Company's pre-petition senior credit facility, Senior Secured Notes, Senior Unsecured Notes and Convertible Senior Unsecured Notes to become immediately due and payable. As a result of the Chapter 11 filings, any efforts to enforce such payment obligations were automatically stayed through the Emergence Date, when the Predecessor Company's debt was canceled. For the Successor 2016 Period, there were no applicable financial covenants with which we had to comply under the First Lien Exit facility, the outstanding New Convertible Notes or the New Building Note.

Credit Facilities

On the Emergence Date, the Company entered into the New First Lien Exit Facility with the lenders party thereto and Royal Bank of Canada, as administrative agent and issuing lender. The initial borrowing base under the New First Lien Exit Facility was $425.0 million, with a maturity date on February 4, 2020. There were no scheduled borrowing base redeterminations until October 2018, followed by scheduled semiannual borrowing base redeterminations thereafter. The outstanding borrowings under the New First Lien Exit Facility bore interest at a rate equal to, at the option of the Company, either (a) a base rate plus an applicable rate of 3.75% per annum or (b) LIBOR plus 4.75% per annum, subject to a 1.00% LIBOR floor. Interest on base rate borrowings was payable quarterly in arrears and interest on LIBOR borrowings was payable every one, two, three or six months, at the election of the Company. The Company had the right to prepay loans under the New First Lien Exit Facility at any time without a prepayment penalty, other than customary "breakage" costs with respect to LIBOR loans.

The New First Lien Exit Facility contained customary affirmative and negative covenants, including as to compliance with laws (including environmental laws, ERISA and anti-corruption laws), maintenance of required insurance, delivery of quarterly and annual financial statements, oil and gas engineering reports, maintenance and operation of property (including oil and gas properties), restrictions on the incurrence of liens, indebtedness, asset dispositions, fundamental changes, restricted payments and other customary covenants. We were in compliance with these covenants as of and for the period ended December 31, 2016.

On February 10, 2017, the New First Lien Exit Facility was refinanced into a new $600.0 million refinanced credit facility with a $425.0 million borrowing base. The refinanced credit facility agreement had the following impacts:

- increased the principal amount of commitments to $600.0 million from $425.0 million;
- extended the maturity date to March 31, 2020 from February 4, 2020;
- borrowing base determinations now include the Company's proportionately consolidated share of proved reserves held by the Royalty Trusts;
- reduced the interest rate from a flat base rate of LIBOR plus 4.75% per annum to a pricing grid tied to borrowing base utilization of (A) LIBOR plus an applicable margin that varies from 3.00% to 4.00% per annum, or (B) the base rate plus an applicable margin that varies from 2.00% to 3.00% per annum;
- reduced the LIBOR floor from 1% to 0%;
- eliminated the minimum proved developing producing reserves asset coverage ratio;
- removed the requirement to maintain $50.0 million in a cash collateral account controlled by the administrative agent;
- eliminated the holiday from borrowing base determinations and the maximum consolidated total net leverage ratio and the minimum consolidated interest coverage ratio covenants; and
- eliminated certain negative covenants, such as the $20.0 million liquidity requirement and the limitation on capital expenditures.

The initial conforming borrowing base under the refinanced credit facility is $425.0 million and the next borrowing base redetermination is scheduled for October 1, 2017, followed by semiannual borrowing base redeterminations thereafter. The amended credit facility is secured by (i) first-priority mortgages on at least 95% of the PV-9 valuation of all proved reserves included in the most recently delivered reserve report of the Company, (ii) a first-priority perfected pledge of substantially all of the capital stock owned by each credit party and equity interests in the Royalty Trusts that are owned by a credit party and (iii) a first-priority perfected security interest in substantially all the cash, cash equivalents, deposits, securities and other similar accounts, and other tangible and intangible assets of the credit parties (including but not limited to as-extracted collateral, accounts receivable, inventory, equipment, general intangibles, investment property, intellectual property, real property and the proceeds of the foregoing). As described above, the refinanced credit facility refinanced and thereby replaced the First Lien Exit Facility.

The refinanced credit facility requires the company to, commencing with the first full quarter ending after the effective date of the refinancing, maintain (i) a maximum consolidated total net leverage ratio, measured as of the end of any fiscal quarter, of no greater than 3.50 to 1.00 and (ii) a minimum consolidated interest coverage ratio, measured as of the end of any fiscal quarter, of no less than 2.25 to 1.00. Such financial covenants are subject to customary cure rights.

The refinanced credit facility contains customary affirmative and negative covenants, including as to compliance with laws (including environmental laws, ERISA and anti-corruption laws), maintenance of required insurance, delivery of quarterly and annual financial statements, oil and gas engineering reports, maintenance and operation of property (including oil and gas properties), restrictions on the incurrence of liens, indebtedness, asset dispositions, fundamental changes, restricted payments and other customary covenants.

The refinanced credit facility includes events of default relating to customary matters, including, among other things, nonpayment of principal, interest or other amounts; violation of covenants; incorrectness of representations and warranties in any material respect; cross-payment default and cross acceleration with respect to indebtedness in an aggregate principal amount of $25.0 million or more; bankruptcy; judgments involving liability of $25.0 million or more that are not paid; and ERISA events. Many events of default are subject to customary notice and cure periods.

At February 24, 2017, there were no amounts outstanding under the refinanced credit facility and approximately $8.0 million in outstanding letters of credit, which reduced the availability under the refinanced credit facility on a dollar for dollar basis.

New Convertible Debt

On the Emergence Date, pursuant to the terms of the Plan, the Company issued approximately $281.8 million principal amount of New Convertible Notes, which did not bear regular interest and were scheduled to mature and mandatorily convert into New Common Stock on October 4, 2020, unless repurchased, redeemed or converted prior to that date. The New Convertible Notes were recorded at fair value upon implementation of fresh start accounting, with the $163.9 million excess value over par recorded as additional paid in capital.

The New Convertible Notes were convertible at the option of the holders at any time up to, and including, the business day immediately preceding the maturity date at an initial convertible at a conversion rate of 0.05330841 shares of New Common Stock per $1.00 principal amount of New Convertible Notes. During the Successor 2016 Period, holders converted approximately $13.0 million par value of New Convertible Notes into approximately 0.7 million shares of New Common Stock. From January

1, 2017 through February 9, 2017, holders converted an additional $5.1 million par value of New Convertible Notes into approximately 0.3 million shares of New Common Stock.

The New Convertible Notes were mandatorily convertible upon certain events, including upon the bona fide refinancing of the New First Lien Exit Facility after a determination by the post-emergence board of directors in good faith that: (a) such refinancing provides for terms that are materially more favorable to the Company and (b) the causing of a conversion is not the primary purpose of such refinancing. As a result of refinancing of New First Lien Exit Facility on February 10, 2017, the remaining outstanding $263.7 million par value of New Convertible Notes on that date converted into approximately 14.1 million shares of New Common Stock.

New Building Note

On the Emergence Date, the Company entered into the New Building Note, which has a principal amount of $35.0 million and is secured by first priority mortgage on the Company's headquarters facility and certain other non-oil and gas real property in downtown Oklahoma City, Oklahoma. The New Building Note was recorded at fair value upon implementation of fresh start accounting. Interest is payable on the New Building Note at 6% per annum for the first year following the Emergence Date, 8% per annum for the second year following the Emergence Date, and 10% thereafter through maturity. Interest is payable in kind from the Emergence Date through the refinancing or repayment of the New First Lien Exit Facility and thereafter in cash. The New Building Note matures on October 4, 2021. On the Emergence Date, pursuant to the Plan, certain holders of the Predecessor Company's Unsecured Senior Notes purchased the New Building Note for $26.8 million in cash, net of certain fees and expenses. The majority of these proceeds were then immediately paid out to certain creditors in accordance with the terms of the Plan. As a result of the Company's entry into the refinanced credit facility, interest on the New Building Note will be paid in cash beginning in 2017. Additionally, the New Building Note was amended in February 2017 in order to allow for pre-payment of principal outstanding.

See "Note 1 - Voluntary Reorganization under Chapter 11 Proceedings " and "Note 11 - Long-Term Debt" to the accompanying consolidated financial statements included in Item 8 of this report for additional discussion of the Company's debt.

Contractual Obligations and Off-Balance Sheet Arrangements

At December 31, 2016, our contractual obligations included long-term debt obligations, third-party drilling rig agreements, asset retirement obligations, operating leases and other individually insignificant obligations. During 2016, the Bankruptcy Court issued orders allowing the rejection of certain long-term contracts that were previously outstanding at December 31, 2015.

As of December 31, 2016, we had future contractual payment commitments under various agreements, which are summarized below. The third-party drilling rig and operating leases are not recorded in the accompanying consolidated balance sheets.

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(In thousands)				
Long-term debt obligations(1)	$322,462	$ 2,305	$7,545	$312,612	$ —
Third-party drilling rig agreements(2)	1,115	1,115	—	—	—
Asset retirement obligations	106,481	66,154	6,785	5,395	28,147
Operating leases and other(3)	18,187	5,650	7,437	900	4,200
Total	$448,245	$ 75,224	$21,767	$318,907	$ 32,347

(1) Includes interest on long-term debt (if any) in the years which it will be incurred, and assumes debt principal amounts are outstanding until their latest contractual maturity, with no additional conversions of New Convertible Notes to common stock.

(2) Includes drilling contracts with third-party drilling rig operators at specified day or footage rates and termination fees associated with our hydraulic fracturing services agreements. All of our drilling rig contracts contain operator performance conditions that allow for pricing adjustments or early termination for operator nonperformance.

(3) Includes the obligation for employee and employer match contributions to the participants of our non-qualified deferred compensation plan for eligible highly compensated employees who elect to defer income exceeding the Internal Revenue Service ("IRS") annual limitations on qualified 401(k) retirement plans.

Valuation Allowance

In 2008 and 2009, the Predecessor Company recorded full cost ceiling impairments totaling $3.5 billion on its oil and natural gas assets, resulting in the Company being in a net deferred tax asset position. Management considered all available evidence and concluded that it was more likely than not that some or all of the deferred tax assets would not be realized and established a valuation allowance against the Company’s net deferred tax asset in the period ending December 31, 2008. This valuation allowance was maintained for the Predecessor Company since 2008. Upon Emergence, the Company’s tax basis in property, plant, and equipment was not significantly impacted by the restructuring and exceeded the book carrying value of its assets at October 1, 2016. Additionally, the Company has a significant U.S. Federal net operating loss of approximately $1.3 billion remaining after the attribute reduction caused by the restructuring transactions. As such, the Successor Company has significant deferred tax assets to consume. See “Note 18—Income Taxes” to the Company’s consolidated financial statements in Item 8 of this report for additional discussion of the impact of the restructuring transactions on the Company’s tax attributes.

Management considered all available evidence in determining whether to establish a valuation allowance on its net deferred tax asset upon emergence and maintain such valuation allowance for the period ending December 31, 2016. Factors considered are, but not limited to, the reversal periods of existing deferred tax liabilities and deferred tax assets, the historical earnings of the Company and the prospects of future earnings. For purposes of the valuation allowance analysis, “earnings” is defined as pre-tax earnings as adjusted for permanent tax adjustments.

The Company experienced losses and was in a cumulative negative earnings position leading up to the petition date for Chapter 11. Further, the Company has a presumption of cumulative negative earnings upon emergence and experienced negative earnings for the Successor 2016 Period ending December 31, 2016. The existence of or presumption of cumulative negative earnings is not a definitive factor in a determination to establish or maintain a valuation allowance as all available evidence should be considered, however it is a significant piece of negative evidence in management’s analysis.

The Company’s revenue, profitability and future growth are substantially dependent upon prevailing and future prices for oil and natural gas. The markets for these commodities continue to be volatile. Relatively modest drops in prices can significantly affect the Company’s financial results and impede its growth. Changes in oil and natural gas prices have a significant impact on the value of the Company’s reserves and on its cash flow. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas and a variety of additional factors that are beyond the Company’s control. Due to these factors, management has placed a lower weight on the prospects of future earnings in its overall analysis of the valuation allowance for the Successor Company at both emergence and for the period ended December 31, 2016.

In determining whether to establish a valuation allowance upon emergence and maintain the valuation allowance at December 31, 2016, management concluded that the objectively verifiable negative evidence of the presumption of cumulative negative earnings upon emergence and actual negative earnings for the period ending December 31, 2016, is difficult to overcome with any forms of positive evidence that may exist. Accordingly, management concluded that it was more likely than not that the Company will not realize a future benefit from certain of the deferred tax assets identified and accordingly placed a full valuation allowance to offset its net deferred tax asset upon emergence. Management has not changed its judgment regarding the need for a full valuation allowance against its net deferred tax asset for the period ending December 31, 2016 for the same reasons. The valuation allowance against the Company’s net deferred tax asset at December 31, 2016 was $1.0 billion. The Predecessor Company’s net deferred tax asset position and corresponding valuation allowance was $1.9 billion and $0.6 billion at December 31, 2015 and December 31, 2014, respectively.

Additionally, at December 31, 2016, the Company has valuation allowances totaling $95.8 million against specific deferred tax assets for which management has determined it is more likely than not that such deferred tax assets will not be realized for various reasons. The valuation allowance against these specific deferred tax assets may not be impacted by a change in judgment with respect to the analysis of the Company’s valuation allowance against its net deferred tax asset.

Critical Accounting Policies and Estimates

The discussion and analysis of the Company's financial condition and results of operations are based upon the Company's consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of the Company's financial statements requires the Company to make assumptions and prepare estimates that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. The Company bases its estimates on historical experience and various other assumptions that the Company believes are reasonable; however, actual results may differ significantly. The Company's critical accounting policies and additional information on significant estimates used by the Company are discussed below. See "Note 3—Summary of Significant Accounting Policies" to the Company's consolidated financial statements in Item 8 of this report for additional discussion of the Company's significant accounting policies.

Fresh Start Accounting. Upon emergence from bankruptcy, the Company applied fresh start accounting to its financial statements because (i) the holders of existing voting shares of the Company prior to its emergence received less than 50% of the voting shares of the Company outstanding following its emergence from bankruptcy and (ii) the reorganization value of the Company's assets immediately prior to confirmation of the plan of reorganization was less than the post-petition liabilities and allowed claims. Fresh start accounting was applied to the Company's consolidated financial statements as of October 1, 2016. Under the principles of fresh start accounting, a new reporting entity was considered to have been created, and, as a result, the Company allocated the reorganization value of the Company to its individual assets, including property, plant and equipment, based on their estimated fair values. As a result of the application of fresh start accounting and the effects of the implementation of the plan of reorganization, the financial statements on or after October 1, 2016 will not be comparable with the financial statements prior to that date.

Derivative Financial Instruments. To manage risks related to fluctuations in prices attributable to its expected oil and natural gas production, the Company enters into oil and natural gas derivative contracts. Entrance into such contracts is dependent upon prevailing or anticipated market conditions. The Company may also, from time to time, enter into interest rate swaps in order to manage risk associated with its exposure to variable interest rates and issue long-term debt that contains embedded derivatives.

The Company recognizes its derivative instruments as either assets or liabilities at fair value with changes in fair value recognized in earnings unless designated as a hedging instrument with specific hedge accounting criteria having been met. The Company has elected not to designate price risk management activities as accounting hedges under applicable accounting guidance, and, accordingly, accounts for its commodity derivative contracts at fair value with changes in fair value reported currently in earnings. The Company's earnings may fluctuate significantly as a result of changes in fair value. Derivative assets and liabilities are netted whenever a legally enforceable master netting agreement exists with the counterparty to a derivative contract. The related cash flow impact of the Company's derivative activities are reflected as cash flows from operating activities unless the derivative contract contains a significant financing element, in which case, cash settlements are classified as cash flows from financing activities in the consolidated statements of cash flows.

Fair values of the substantial majority of the Company's commodity derivative financial instruments are determined primarily by using discounted cash flow calculations or option pricing models, and are based upon inputs that are either readily available in the public market, such as oil and natural gas futures prices, volatility factors, interest rates and discount rates, or can be corroborated from active markets. Estimates of future prices are based upon published forward commodity price curves for oil and natural gas instruments. Valuations also incorporate adjustments for the nonperformance risk of the Company or its counterparties, as applicable.

Proved Reserves. Approximately 94.0% of the Company's reserves were estimated by independent petroleum engineers for the year ended December 31, 2016. Estimates of proved reserves are based on the quantities of oil, natural gas and NGLs that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. However, there are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future revenues, rates of production and timing of development expenditures, including many factors beyond the Company's control. Estimating reserves is a complex process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner and relies on assumptions and subjective interpretations of available geologic, geophysical, engineering and production data, and the accuracy of reserve estimates is a function of the quality and quantity of available data, engineering and geological interpretation and judgment. In addition, as a result of volatility and changing market conditions, commodity prices and future development costs will change from period to period, causing estimates of proved reserves to change, as well as causing estimates of future net revenues to change. For the years ended December 31, 2016, 2015 and 2014, the Company revised its proved reserves from prior years' reports by approximately (105.4) MMBoe, (234.6) MMBoe and 20.3 MMBoe, respectively, due to production performance indicating more (or less) reserves in place, market prices during or at the end of the applicable period, larger (or smaller) reservoir size than initially estimated or additional proved reserve bookings within the original field boundaries. Estimates of proved reserves are key components of the Company's most significant financial estimates used to determine depreciation and depletion on oil and natural gas properties and its full cost ceiling limitation. Future revisions to estimates of proved reserves may be material and could materially affect the Company's future depreciation, depletion and impairment expenses. As part of fresh start accounting, proved reserves were adjusted to their estimated fair value as of October 1, 2016, as described in "Note 2—Fresh Start Accounting."

Method of Accounting for Oil and Natural Gas Properties. The Company's business is subject to accounting rules that are unique to the oil and natural gas industry. There are two allowable methods of accounting for oil and natural gas business activities: the successful efforts method and the full cost method. The Company uses the full cost method to account for its oil and natural gas properties. All direct costs and certain indirect costs associated with the acquisition, exploration and development of oil and natural gas properties are capitalized. Exploration and development costs include dry well costs, geological and geophysical costs, direct overhead related to exploration and development activities and other costs incurred for the purpose of finding oil, natural gas and NGL reserves. Amortization of oil and natural gas properties is calculated using the unit-of-production method based on estimated proved oil, natural gas and NGL reserves. Sales and abandonments of oil and natural gas properties being amortized are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustments would significantly alter the relationship between capitalized costs and proved oil, natural gas and NGL reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the proved reserve quantities of a cost center.

Under the successful efforts method, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion and impairment of oil and natural gas properties are generally calculated on a well by well, lease or field basis versus the aggregated "full cost" pool basis. Additionally, gain or loss is generally recognized on all sales of oil and natural gas properties under the successful efforts method. As a result, the Company's financial statements will differ from companies that apply the successful efforts method since the Company will generally reflect a higher level of capitalized costs as well as a higher oil and natural gas depreciation and depletion rate, and the Company will not have exploration expenses that successful efforts companies frequently have.

Impairment of Oil and Natural Gas Properties. In accordance with full cost accounting rules, capitalized costs are subject to a limitation. The capitalized cost of oil and natural gas properties, net of accumulated depreciation, depletion and impairment, less related deferred income taxes, may not exceed an amount equal to the present value of future net revenues from proved oil, natural gas and NGL reserves, discounted at 10% per annum, plus the lower of cost or fair value of unproved properties, plus estimated salvage value, less related tax effects (the "ceiling limitation"). The Company calculates its full cost ceiling limitation using the 12-month average oil and natural gas prices for the most recent 12 months as of the balance sheet date and adjusted for basis or location differential, held constant over the life of the reserves. If capitalized costs exceed the ceiling limitation, the excess must be charged to expense. Once incurred, a write-down cannot be reversed at a later date. The Successor Company recorded a full cost ceiling impairment of $319.1 million for the period from October 2, 2016 through December 31, 2016, and the Predecessor Company recorded full cost ceiling impairments of $657.4 million, $4.5 billion and $164.8 million for the period from January 1, 2016 through October 1, 2016, and the years ended December 31, 2015, and 2014, respectively. See "Consolidated Results of Operations" for additional discussion of full cost ceiling impairments.

Unproved Properties. The balance of unproved properties consists primarily of costs to acquire unproved acreage. These costs are initially excluded from the Company's amortization base until it is known whether proved reserves will or will not be assigned to the property. The Company assesses all properties, on an individual basis or as a group if properties are individually insignificant, classified as unproved on a quarterly basis for possible impairment or reduction in value. The assessment includes consideration of various factors, including, but not limited to, the following: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; assignment of proved reserves; and economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, all or a portion of the associated leasehold costs are transferred to the full cost pool and become subject to amortization. Costs of seismic data are allocated to various unproved leaseholds and transferred to the amortization base with the associated leasehold costs on a specific project basis. The Company estimates that substantially all of its costs classified as unproved as of the balance sheet date will be evaluated and transferred within a 10-year period from the date of acquisition, contingent on the Company’s capital expenditures and drilling program. As part of fresh start accounting, proved reserves were adjusted to their estimated fair value as of October 1, 2016, as described in “Note 2—Fresh Start Accounting.”

Property, Plant and Equipment, Net. Other capitalized costs, including drilling equipment, natural gas gathering and treating equipment, transportation equipment and other property and equipment are carried at cost. Renewals and improvements are capitalized while repairs and maintenance are expensed. Depreciation of such property and equipment is computed using the straight-line method over the estimated useful lives of the assets, which range from 10 to 39 years for buildings and 2 to 30 years for equipment. When property and equipment components are disposed of, the cost and the related accumulated depreciation are removed and any resulting gain or loss is reflected in operations. Realization of the carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying value of such asset or asset group may not be recoverable. Assets are considered to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset or asset group including disposal value, if any, is less than the carrying amount of the asset or asset group. If an asset or asset group is determined to be impaired, the impairment loss is measured as the amount by which the carrying amount of the asset or asset group exceeds its fair value. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two as considered appropriate based on the circumstances. The Company may also determine fair value by using the present value of estimated future cash inflows and/or outflows, or third-party offers or prices of comparable assets with consideration of current market conditions to value its non-financial assets and liabilities when circumstances dictate determining fair value is necessary. Changes in such estimates could cause the Company to reduce the carrying value of property and equipment. As part of fresh start accounting, property, plant and equipment were adjusted to their estimated fair value and depreciable lives were revised as of October 1, 2016, as described in “Note 2—Fresh Start Accounting.”

See “—Consolidated Results of Operations” and “Note 9—Impairment” to the Company’s consolidated financial statements in Item 8 of this report for a discussion of the Company’s impairments.

Asset Retirement Obligations. Asset retirement obligations represent the estimate of fair value of the cost to plug, abandon and remediate the Company’s wells at the end of their productive lives, in accordance with applicable federal and state laws. The Company estimates the fair value of an asset’s retirement obligation in the period in which the liability is incurred (at the time the wells are drilled or acquired). Estimating future asset retirement obligations requires management to make estimates and judgments regarding timing, existence of a liability and what constitutes adequate restoration. The Company employs a present value technique to estimate the fair value of an asset retirement obligation, which reflects certain assumptions and requires significant judgment, including an inflation rate, its credit-adjusted, risk-free interest rate, the estimated settlement date of the liability and the estimated current cost to settle the liability based on third-party quotes and current actual costs. Inherent in the present value calculation rates are the timing of settlement and changes in the legal, regulatory, environmental and political environments, which are subject to change. Changes in timing or to the original estimate of cash flows will result in changes to the carrying amount of the liability.

Revenue Recognition. Oil, natural gas and NGL revenues are recorded when title of production sold passes to the customer, net of royalties, discounts and allowances, as applicable. The Successor Company has made an accounting policy election to deduct transportation costs from oil, natural gas and NGL revenues. Taxes assessed by governmental authorities on oil, natural gas and NGL sales are presented separately from such revenues and included in production tax expense in the consolidated statements of operations.

Income Taxes. Deferred income taxes are recorded for temporary differences between the financial statement and income tax basis of assets and liabilities. Deferred tax assets are recognized for temporary differences that will be deductible in future years’ tax returns and for operating loss and tax credit carryforwards. Deferred tax assets are reduced by a valuation allowance if it is deemed more likely than not that some or all of the deferred tax assets will not be realized. Deferred tax liabilities are recognized for temporary differences that will be taxable in future years’ tax returns. As of December 31, 2016, the Company had a full valuation allowance against its net deferred tax asset. The valuation allowance serves to reduce the tax benefits recognized from the net deferred tax asset to an amount that is more likely than not to be realized based on the weight of all available evidence.

New Accounting Pronouncements. For a discussion of recently adopted accounting standards and recent accounting standards not yet adopted, see “Note 3—Summary of Significant Accounting Policies” to the Company’s consolidated financial statements in Item 8 of this report.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

General

This discussion provides information about the financial instruments we use to manage commodity prices. All contracts are settled in cash and do not require the actual delivery of a commodity at settlement. Additionally, our exposure to credit risk and interest rate risk is also discussed.

Commodity Price Risk. Our most significant market risk relates to the prices we receive for oil, natural gas and NGLs. Due to the historical price volatility of these commodities, from time to time, depending upon management's view of opportunities under the then-prevailing market conditions, we enter into commodity pricing derivative contracts for a portion of our anticipated production volumes for the purpose of reducing the variability of oil and natural gas prices received. The New First Lien Exit Facility limits our ability to enter into derivative transactions to 90% of expected production volumes from estimated proved reserves.

We use, and may continue to use, a variety of commodity-based derivative contracts, including fixed price swaps, basis swaps and collars. At December 31, 2016, our commodity derivative contracts consisted of fixed price swaps, under which the Company receives a fixed price for the contract and pays a floating market price to the counterparty over a specified period for a contracted volume.

Our oil fixed price swap transactions are settled based upon the average daily prices for the calendar month or quarter of the contract period, and our natural gas fixed price swap transactions are settled based upon the last day settlement of the first nearby month futures contract of the contract period. Settlement for oil derivative contracts occurs in the succeeding month or quarter and natural gas derivative contracts are settled in the production month or quarter.

At December 31, 2016, our open commodity derivative contracts consisted of the following:

Oil Price Swaps

	Notional (MBbls)	Weighted Average Fixed Price
January 2017 - December 2017	3,285	$ 52.24
January 2018 - December 2018	1,825	$ 55.34

Natural Gas Price Swaps

	Notional (MMcf)	Weighted Average Fixed Price
January 2017 - December 2017	32,850	$ 3.20
January 2018 - December 2018	3,650	$ 3.12

Because we have not designated any of our derivative contracts as hedges for accounting purposes, changes in fair values of our derivative contracts are recognized as gains and losses in current period earnings. As a result, our current period earnings may be significantly affected by changes in the fair value of our commodity derivative contracts. Changes in fair value are principally measured based on future prices as of period-end compared to the contract price.

We recorded a loss on commodity derivative contracts of $25.7 million and $4.8 million for the Successor 2016 Period and the Predecessor 2016 Period, respectively, as reflected in the accompanying consolidated statements of operations, which includes net cash receipts upon settlement of $7.7 million and $72.6 million, respectively. The net receipts for the Predecessor 2016 Period include $17.9 million of cash receipts related to early settlements of commodity derivative contracts in the second quarter of 2016 after the Chapter 11 filings occurred.

We recorded gains on commodity derivative contracts of $73.1 million and $334.0 million for the years ended December 31, 2015 and 2014, respectively, as reflected in the consolidated statements of operations in Item 8 of this report, which includes net cash (receipts) payments upon settlement of $(327.7) million and $32.3 million, respectively. Included in the net cash payments for 2014 are $69.6 million of cash payments related to early settlements primarily as a result of the sale of the Gulf Properties in February 2014.

See “Note 12—Derivatives” to the consolidated financial statements in Item 8 of this report for additional information regarding the Company’s commodity derivatives.

Credit Risk. All of our derivative transactions have been carried out in the over-the-counter market. The use of derivative transactions in over-the-counter markets involves the risk that the counterparties may be unable to meet the financial terms of the transactions. The counterparties for all of our derivative transactions have an “investment grade” credit rating. We monitor the credit ratings of our derivative counterparties and consider our counterparties’ credit default risk ratings in determining the fair value of our derivative contracts. Our derivative contracts are with multiple counterparties to minimize exposure to any individual counterparty.

Both the default under the Predecessor’s senior credit facility and the Chapter 11 filing constituted defaults under our commodity derivative contracts. As a result, certain commodity derivative contracts were settled in the second quarter of 2016 and prior to their contractual maturities after the Chapter 11 filings occurred.

We do not require collateral or other security from counterparties to support derivative instruments. We have master netting agreements with each of our remaining derivative contract counterparties, which allow us to net our derivative assets and liabilities by commodity type with the same counterparty. As a result of the netting provisions, our maximum amount of loss under derivative transactions due to credit risk is limited to the net amounts due from the counterparties under the commodity derivative contracts. Our loss is further limited as any amounts due from a defaulting counterparty that is a lender under the New First Lien Exit Facility or subsequently, the refinanced credit facility, can be offset against amounts owed, if any, to such counterparty. As of December 31, 2016, the counterparties to our open commodity derivative contracts were all also lenders under the First Lien Exit Facility. As a result, we were not required to post additional collateral under our commodity derivative contracts.

Interest Rate Risk. We are exposed to interest rate risk on our variable rate debt. Variable rate debt, where the interest rate fluctuates, exposes us to short-term changes in market interest rates as our interest obligations on these instruments are periodically redetermined based on prevailing market interest rates, primarily LIBOR and the federal funds rate. We had no outstanding variable rate debt as of December 31, 2016.

Item 8. Financial Statements and Supplementary Data

The Company’s consolidated financial statements required by this item are included in this report beginning on page F-1.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures.

Under the supervision and with the participation of the Company's management, including its Chief Executive Officer and Chief Financial Officer, the Company performed an evaluation of the effectiveness of the design and operation of its disclosure controls and procedures pursuant to Exchange Act Rules 13a-15(b) and 15d-15(b) as of the end of the period covered by this annual report. Based on that evaluation, the Company's Chief Executive Officer and its Chief Financial Officer concluded that its disclosure controls and procedures were effective as of December 31, 2016 to provide reasonable assurance that the information required to be disclosed by the Company in its reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting

The information required to be filed pursuant to this item is set forth under the captions "Management's Report on Internal Control over Financial Reporting" in Item 8 of this report.

Changes in Internal Control over Financial Reporting

There were no changes in the Company's internal control over financial reporting during the quarter ended December 31, 2016 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. Other Information

Not Applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the following sections of the Company's definitive proxy statement, which will be filed no later than May 1, 2017: "Director Biographical Information," "Executive Officers," "Compliance with Section 16(a) of the Exchange Act" and "Corporate Governance Matters."

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the following sections of the Company's definitive proxy statement, which will be filed no later than May 1, 2017: "Director Compensation," "Outstanding Equity Awards" and "Executive Officers and Compensation."

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by this item is incorporated herein by reference to the following sections of the Company’s definitive proxy statement, which will be filed no later than May 1, 2017: “Equity Compensation Plan Information” and “Security Ownership of Certain Beneficial Owners and Management.”

Item 13. Certain Relationships and Related Transactions and Director Independence

The information required by this item is incorporated herein by reference to the following sections of the Company’s definitive proxy statement, which will be filed no later than May 1, 2017: “Related Party Transactions” and “Corporate Governance Matters.”

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the section captioned “Ratification of Selection of Independent Registered Public Accounting Firm” in the Company’s definitive proxy statement, which will be filed no later than May 1, 2017.

PART IV

Item 15. Exhibits and Financial Statement Schedules

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

(1)Consolidated Financial Statements

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

(2)Financial Statement Schedules

All financial statement schedules have been omitted because they are not applicable or the required information is presented in the consolidated financial statements or notes thereto.

(3)Exhibits

Item 16. Form 10-K Summary

Not Applicable.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Management's Report on Internal Control over Financial Reporting

Management of SandRidge Energy, Inc. is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Internal control over financial reporting is a process designed by, or under the supervision of, the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013) (the COSO criteria). Based on management's assessment using the COSO criteria, management concluded the Company's internal control over financial reporting was effective as of December 31, 2016.

/s/ JAMES D. BENNETT	/s/ JULIAN BOTT
James D. Bennett	Julian Bott
President and Chief Executive Officer	Executive Vice President and Chief Financial Officer

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of SandRidge Energy, Inc.

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of operations, changes in stockholders’ equity and cash flows present fairly, in all material respects, the financial position of SandRidge Energy, Inc. and its subsidiaries (Successor Company) as of December 31, 2016 and the results of their operations and their cash flows for the period from October 2, 2016 to December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, the United States Bankruptcy Court for the district of Southern Texas confirmed the Company's Amended Joint Chapter 11 Plan of Reorganization (the "Plan") on September 9, 2016. Confirmation of the Plan resulted in the discharge of all claims against the Company that arose before October 1, 2016 and substantially alters or terminates all rights and interests of equity security holders as provided for in the Plan. The Plan was substantially consummated on October 4, 2016 and the Company emerged from bankruptcy. In connection with its emergence from bankruptcy, the Company adopted fresh start accounting as of October 1, 2016.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Oklahoma City, Oklahoma
March 3, 2017

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of SandRidge Energy, Inc.:

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of operations, changes in stockholders' equity and cash flows present fairly, in all material respects, the financial position of SandRidge Energy, Inc. and its subsidiaries (Predecessor Company) as of December 31, 2015 and the results of their operations and their cash flows for the period from January 1, 2016 to October 1, 2016, and for each of the two years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, the Company filed a petition on May 16, 2016 with the United States Bankruptcy Court for the district of Southern Texas for reorganization under the provisions of Chapter 11 of the Bankruptcy Code. The Company's Amended Joint Chapter 11 Plan of Reorganization was substantially consummated on October 4, 2016 and the Company emerged from bankruptcy. In connection with its emergence from bankruptcy, the Company adopted fresh start accounting.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Oklahoma City, Oklahoma
March 3, 2017

SandRidge Energy, Inc. and Subsidiaries
Consolidated Balance Sheets
(In thousands, except per share data)

	Successor December 31, 2016	Predecessor December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 121,231	$ 435,588
Restricted cash - collateral	50,000	—
Restricted cash - other	2,840	—
Accounts receivable, net	74,097	127,387
Derivative contracts	—	84,349
Prepaid expenses	5,375	6,833
Other current assets	3,633	19,931
Total current assets	257,176	674,088
Oil and natural gas properties, using full cost method of accounting		
Proved (includes development and project costs excluded from amortization of $16.7 million and $34.6 million at December 31, 2016 and 2015, respectively)	840,201	12,529,681
Unproved	74,937	363,149
Less: accumulated depreciation, depletion and impairment	(353,030)	(11,149,888)
	562,108	1,742,942
Other property, plant and equipment, net	255,824	491,760
Other assets	6,284	13,237
Total assets	$ 1,081,392	$ 2,922,027

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

F-5

SandRidge Energy, Inc., and Subsidiaries
Consolidated Balance Sheets—Continued
(In thousands, except per share data)

	Successor December 31, 2016	Predecessor December 31, 2015
LIABILITIES AND STOCKHOLDERS' (DEFICIT) EQUITY		
Current liabilities		
Accounts payable and accrued expenses	$ 116,517	$ 428,417
Derivative contracts	27,538	573
Asset retirement obligations	66,154	8,399
Other current liabilities	3,497	—
Total current liabilities	213,706	437,389
Long-term debt	305,308	3,562,378
Derivative contracts	2,176	—
Asset retirement obligations	40,327	95,179
Other long-term obligations	6,958	14,814
Total liabilities	568,475	4,109,760
Commitments and contingencies (Note 14)		
Equity		
SandRidge Energy, Inc. stockholders' equity (deficit)		
Predecessor preferred stock, $0.001 par value, 50,000 shares authorized		
8.5% Convertible perpetual preferred stock; 2,650 shares issued and outstanding at December 31, 2015; aggregate liquidation preference of $265,000	—	3
7.0% Convertible perpetual preferred stock; 2,770 shares issued and outstanding at December 31, 2015, aggregate liquidation preference of $277,000	—	3
Predecessor common stock, $0.001 par value; 1,800,000 shares authorized, 635,584 issued and 633,471 outstanding at December 31, 2015	—	630
Predecessor additional paid-in capital	—	5,301,136
Predecessor additional paid-in capital—stockholder receivable	—	(1,250)
Predecessor treasury stock, at cost	—	(5,742)
Successor common stock, $0.001 par value; 250,000 shares authorized; 21,042 issued and 19,635 outstanding at December 31, 2016	20	—
Successor warrants	88,381	—
Successor additional paid-in capital	758,498	—
Accumulated deficit	(333,982)	(6,992,697)
Total SandRidge Energy, Inc. stockholders' equity (deficit)	512,917	(1,697,917)
Noncontrolling interest	—	510,184
Total stockholders' equity (deficit)	512,917	(1,187,733)
Total liabilities and stockholders' equity (deficit)	$ 1,081,392	$ 2,922,027

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

SandRidge Energy, Inc. and Subsidiaries
Consolidated Statements of Operations
For the Period from October 2, 2016 through December 31, 2016, the Period from January 1, 2016 through October 1, 2016 and the Years Ended December 31, 2015 and 2014
(In thousands, except per share amounts)

	Successor	Predecessor		
	Period from October 2, 2016 through December 31, 2016	Period from January 1, 2016 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Revenues				
Oil, natural gas and NGL	$98,307	$279,971	$707,434	$1,420,879
Other	149	13,838	61,275	137,879
Total revenues	98,456	293,809	768,709	1,558,758
Expenses				
Production	24,997	129,608	308,701	346,088
Production taxes	2,643	6,107	15,440	31,731
Depreciation and depletion—oil and natural gas	33,971	86,613	319,913	434,295
Depreciation and amortization—other	3,922	21,323	47,382	59,636
Accretion of asset retirement obligations	2,090	4,365	4,477	9,092
Impairment	319,087	718,194	4,534,689	192,768
General and administrative	9,837	116,091	137,715	113,991
Employee termination benefits	12,334	18,356	12,451	8,874
Loss (gain) on derivative contracts	25,652	4,823	(73,061)	(334,011)
Loss on settlement of contract	—	90,184	50,976	—
Other operating expenses	268	4,348	52,704	106,070
Total expenses	434,801	1,200,012	5,411,387	968,534
(Loss) income from operations	(336,345)	(906,203)	(4,642,678)	590,224
Other (expense) income				
Interest expense	(372)	(126,099)	(321,421)	(244,109)
Gain on extinguishment of debt	—	41,179	641,131	—
Gain on reorganization items, net	—	2,430,599	—	—
Other income, net	2,744	1,332	2,040	3,490
Total other income (expense)	2,372	2,347,011	321,750	(240,619)
(Loss) income before income taxes	(333,973)	1,440,808	(4,320,928)	349,605
Income tax expense (benefit)	9	11	123	(2,293)
Net (loss) income	(333,982)	1,440,797	(4,321,051)	351,898
Less: net (loss) income attributable to noncontrolling interest	—	—	(623,506)	98,613
Net (loss) income attributable to SandRidge Energy, Inc.	(333,982)	1,440,797	(3,697,545)	253,285
Preferred stock dividends	—	16,321	37,950	50,025
(Loss applicable) income available to SandRidge Energy, Inc. common stockholders	$(333,982)	$1,424,476	$(3,735,495)	$203,260
(Loss) earnings per share				
Basic	$(17.61)	$2.01	$(7.16)	$0.42
Diluted	$(17.61)	$2.01	$(7.16)	$0.42
Weighted average number of common shares outstanding				

Basic	18,967	708,928	521,936	479,644
Diluted	18,967	708,928	521,936	499,743

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

SandRidge Energy, Inc. and Subsidiaries
Consolidated Statements of Changes in Stockholders' Equity (Deficit)
For the Period from October 2, 2016 through December 31, 2016, the Period from January 1, 2016 through October 1, 2016 and the Years Ended December 31, 2015 and 2014

	Convertible Perpetual Preferred Stock		Common Stock		Additional Paid-In Capital	Treasury Stock	Accumulated Deficit	Non-controlling Interest	Total
	Shares	Amount	Shares	Amount					
	(In thousands)								
Balance at December 31, 2013 - Predecessor	7,650	$ 8	490,290	$ 483	$ 5,294,551	$ (8,770)	$ (3,460,462)	$ 1,349,817	$ 3,175,627
Sale of royalty trust units	—	—	—	—	4,091	—	—	18,028	22,119
Distributions to noncontrolling interest owners	—	—	—	—	—	—	—	(193,807)	(193,807)
Purchase of treasury stock	—	—	—	—	—	(6,373)	—	—	(6,373)
Retirement of treasury stock	—	—	—	—	(6,373)	6,373	—	—	—
Stock distributions, net of purchases - retirement plans	—	—	206	—	(1,781)	1,790	—	—	9
Stock-based compensation	—	—	—	—	23,665	—	—	—	23,665
Stock-based compensation excess tax provision	—	—	—	—	14	—	—	—	14
Payment received on shareholder receivable	—	—	—	—	1,250	—	—	—	1,250
Issuance of restricted stock awards, net of cancellations	—	—	3,311	3	(3)	—	—	—	—
Acquisition of ownership interest	—	—	—	—	(2,074)	—	—	(656)	(2,730)
Repurchase of common stock	—	—	(27,411)	(27)	(111,800)	—	—	—	(111,827)
Conversion of 6% preferred stock	(2,000)	(2)	18,423	18	(16)	—	—	—	—
Net income	—	—	—	—	—	—	253,285	98,613	351,898
Convertible perpetual	—	—	—	—	—	—	(50,025)	—	(50,025)

preferred stock dividends									
Balance at December 31, 2014 - Predecessor	5,650	6	484,819	477	5,201,524	(6,980)	(3,257,202)	1,271,995	3,209,820
Distributions to noncontrolling interest owners	—	—	—	—	—	—	—	(138,305)	(138,305)
Purchase of treasury stock	—	—	—	—	—	(2,428)	—	—	(2,428)
Retirement of treasury stock	—	—	—	—	(2,428)	2,428	—	—	—
Stock distributions, net of purchases - retirement plans	—	—	(1,000)	—	(916)	1,238	—	—	322
Stock-based compensation	—	—	—	—	21,123	—	—	—	21,123
Payment received on shareholder receivable	—	—	—	—	1,250	—	—	—	1,250
Issuance of restricted stock awards, net of cancellations	—	—	1,514	5	(5)	—	—	—	—
Common stock issued for debt	—	—	120,881	121	63,178	—	—		63,299
Conversion of preferred stock to common stock	(230)	—	2,968	3	(3)	—	—	—	—
Net loss	—	—	—	—	—	—	(3,697,545)	(623,506)	(4,321,051)
Convertible perpetual preferred stock dividends	—	—	24,289	24	16,163	—	(37,950)	—	(21,763)
Balance at December 31, 2015 - Predecessor	5,420	$ 6	633,471	$ 630	$ 5,299,886	$ (5,742)	$ (6,992,697)	$ 510,184	$ (1,187,733)

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

SandRidge Energy, Inc. and Subsidiaries
Consolidated Statements of Changes in Stockholders' Equity (Deficit)—Continued
For the Period from October 2, 2016 through December 31, 2016, the Period from January 1, 2016 through October 1, 2016 and Years Ended December 31, 2015 and 2014

	Convertible Perpetual Preferred Stock		Common Stock		Additional Paid-In Capital	Treasury Stock	Accumulated Deficit	Non-controlling Interest	Total
	Shares	Amount	Shares	Amount					
	(In thousands)								
Balance at December 31, 2015 - Predecessor	5,420	$ 6	633,471	$ 630	$ 5,299,886	$ (5,742)	$ (6,992,697)	$ 510,184	$ (1,187,733)
Cumulative effect of adoption of ASU 2015-02	—	—	—	—	—	—	257,081	(510,205)	(253,124)
Purchase of treasury stock	—	—	—	—	—	(44)	—	—	(44)
Retirement of treasury stock	—	—	—	—	(44)	44	—	—	—
Stock distributions, net of purchases - retirement plans	—	—	603	—	(860)	524	—	—	(336)
Stock-based compensation	—	—	—	—	11,102	—	—	—	11,102
Cancellations of restricted stock awards, net of issuance	—	—	(2,184)	2	(2)	—	—	—	—
Common stock issued for debt	—	—	84,390	84	4,325	—	—	—	4,409
Conversion of preferred stock to common stock	(173)	—	2,220	2	(2)	—	—	—	—
Net income	—	—	—	—	—	—	1,440,797	—	1,440,797
Convertible perpetual preferred stock dividends	—	—	—	—	—	—	(16,321)	—	(16,321)
Balance at October 1, 2016 - Predecessor	5,247	6	718,500	718	5,314,405	(5,218)	(5,311,140)	(21)	(1,250)
Cancellation of Predecessor equity	(5,247)	(6)	(718,500)	(718)	(5,314,405)	5,218	5,311,140	21	1,250
Balance at October 1, 2016 - Predecessor	—	$ —	—	$ —	$ —	$ —	$ —	$ —	$ —

	Common Stock Shares (In thousands)	Amount	Warrants Shares	Amount	Additional Paid-In Capital	Treasury Stock	Accumulated Deficit	Total
Balance at October 1, 2016 - Predecessor	—	$ —	—	$—	$—	$ —	$—	$—
Issuance of Successor common stock	18,932	19	—	—	575,144	—	—	575,163
Issuance of Successor warrants	—	—	6,442	88,382	—	—	—	88,382
Convertible note premium	—	—	—	—	163,879	—	—	163,879
Balance at October 1, 2016 - Predecessor	18,932	$ 19	6,442	$88,382	$739,023	$ —	$—	$827,424
Balance at October 1, 2016 - Successor	18,932	$ 19	6,442	$88,382	$739,023	$ —	$—	$827,424
Issuance of stock awards, net of cancellations	10	—	—	—	—	—	—	—
Common stock issued for debt	693	1	—	—	13,000	—	—	13,001
Common stock issued for warrants	—	—	—	(1)	4	—	—	3
Stock-based compensation	—	—	—	—	6,581	—	—	6,581
Purchase of treasury stock	—	—	—	—	—	(110)	—	(110)
Retirement of treasury stock	—	—	—	—	(110)	110	—	—
Net loss	—	—	—	—	—	—	(333,982)	(333,982)
Balance at December 31, 2016 - Successor	19,635	$ 20	6,442	$88,381	$758,498	$ —	$(333,982)	$512,917

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

SandRidge Energy, Inc. and Subsidiaries
Consolidated Statements of Cash Flows
For the Period from October 2, 2016 through December 31, 2016, the Period from January 1, 2016 through October 1, 2016 and the Years Ended December 31, 2015 and 2014
(In thousands)

	Successor	Predecessor		
	Period from October 2, 2016 through December 31, 2016	Period from January 1, 2016 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
CASH FLOWS FROM OPERATING ACTIVITIES				
Net (loss) income	$(333,982)	$1,440,797	$(4,321,051)	$351,898
Adjustments to reconcile net (loss) income to net cash provided by (used in) operating activities				
Provision for doubtful accounts	(13,166)	16,704	—	—
Depreciation, depletion and amortization	37,893	107,936	367,295	493,931
Accretion of asset retirement obligations	2,090	4,365	4,477	9,092
Impairment	319,087	718,194	4,534,689	192,768
Gain on reorganization items, net	—	(2,442,436)	—	—
Debt issuance costs amortization	—	4,996	11,884	9,425
Amortization of discount, net of premium, on debt	(81)	2,734	3,130	529
Gain on extinguishment of debt	—	(41,179)	(641,131)	—
Write off of debt issuance costs	—	—	7,108	—
(Gain) loss on debt derivatives	—	(1,324)	10,377	—
Cash paid for early conversion of convertible notes	—	(33,452)	(32,741)	—
Loss (gain) on derivative contracts	25,652	4,823	(73,061)	(334,011)
Cash received on settlement of derivative contracts	7,698	72,608	327,702	11,796
Loss on settlement of contract	—	90,184	50,976	—
Cash paid on settlement of contract	—	(11,000)	(24,889)	—
Stock-based compensation	6,250	9,075	18,380	19,994
Other	717	(3,260)	2,842	417
Changes in operating assets and liabilities increasing (decreasing) cash				
Deconsolidation of noncontrolling interest	—	(9,654)	—	—
Receivables	12,872	36,116	201,907	(63,492)
Prepaid expenses	(1,079)	(5,681)	1,148	9,549
Other current assets	(260)	(181)	12,710	3,164
Other assets and liabilities, net	1,505	(7,542)	2,239	(1,132)
Accounts payable and accrued expenses	990	(61,305)	(86,470)	(66,492)
Asset retirement obligations	(591)	(3,595)	(3,984)	(16,322)
Net cash provided by (used in) operating activities	65,595	(112,077)	373,537	621,114
CASH FLOWS FROM INVESTING ACTIVITIES				
Capital expenditures for property, plant and equipment	(51,676)	(186,452)	(879,201)	(1,553,332)
Acquisitions of assets	—	(1,328)	(216,943)	(18,384)
Proceeds from sale of assets	11,841	20,090	56,504	714,475
Net cash used in investing activities	(39,835)	(167,690)	(1,039,640)	(857,241)

CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from borrowings	—	489,198	2,065,000	—
Repayments of borrowings	(414,954)	(74,243)	(939,466)	—
Debt issuance costs	—	(333)	(53,244)	(3,947)
Proceeds from building mortgage	—	26,847	—	—
Payment of mortgage proceeds and cash recovery to debt holders	—	(33,874)	—	—
Proceeds from the sale of royalty trust units	—	—	—	22,119
Noncontrolling interest distributions	—	—	(138,305)	(193,807)
Purchase of treasury stock	(110)	(44)	(3,535)	(8,702)
Repurchase of common stock	—	—	—	(111,827)
Dividends paid—preferred	—	—	(11,262)	(55,525)
Cash paid on settlement of financing derivative contracts	—	—	—	(44,128)
Other	3	—	1,250	(1,466)
Net cash (used in) provided by financing activities	(415,061)	407,551	920,438	(397,283)
NET (DECREASE) INCREASE IN CASH, CASH EQUIVALENTS and RESTRICTED CASH	(389,301)	127,784	254,335	(633,410)
CASH, CASH EQUIVALENTS and RESTRICTED CASH, beginning of year	563,372	435,588	181,253	814,663
CASH, CASH EQUIVALENTS and RESTRICTED CASH end of year	$174,071	$563,372	$435,588	$181,253

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

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements

1. Voluntary Reorganization under Chapter 11 Proceedings

On May 16, 2016, the Company and certain of its direct and indirect subsidiaries (collectively with the Company, 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, and the Debtors' subsequently emerged from bankruptcy on October 4, 2016 (the "Emergence Date"). Although the Company is no longer a debtor-in-possession, the Company was a debtor-in-possession through October 4, 2016. As such, the Company's bankruptcy proceedings and related matters have been summarized below.

The Company was able to conduct normal business activities and pay associated obligations for the period following its bankruptcy filing and was authorized to pay and has paid certain pre-petition obligations, including employee wages and benefits, goods and services provided by certain vendors, transportation of the Company's production, royalties and costs incurred on the Company's behalf by other working interest owners. During the pendency of the Chapter 11 case, all transactions outside the ordinary course of business required the prior approval of the Bankruptcy Court.

Automatic Stay. Subject to certain specific exceptions under the Bankruptcy Code, the Chapter 11 filings automatically stayed most judicial or administrative actions against the Company and efforts by creditors to collect on or otherwise exercise rights or remedies with respect to pre-petition claims. Absent an order from the Bankruptcy Court, substantially all of the Debtors' pre-petition liabilities were subject to settlement under the Bankruptcy Code.

Plan of Reorganization. In accordance with the plan of reorganization confirmed by the Bankruptcy Court (the "Plan"), the following significant transactions occurred upon the Company's emergence from bankruptcy on October 4, 2016:

- First Lien Credit Agreement. All outstanding obligations under the senior secured revolving credit facility (the "senior credit facility") were canceled, and claims under the senior credit facility received their proportionate share of (a) $35.0 million in cash and (b) participation in the newly established $425.0 million reserve-based revolving credit facility (the "New First Lien Exit Facility"). Refer to Note 11 for additional information.

- Cash Collateral Account. The Company deposited $50.0 million of cash in an account controlled by the administrative agent to the New First Lien Exit Facility (the "Cash Collateral Account") from the Emergence Date until the first borrowing base redetermination in October 2018 (the "Protected Period"); provided that (a) (i) $12.5 million will be released to the Company upon delivery of an acceptable business plan to the administrative agent, (ii) $12.5 million will be released to the Company upon achievement for two consecutive quarters of certain milestones set forth in the business plan and (b) to the extent the foregoing amounts are not released to the Company, up to $25.0 million will be released to the Company upon meeting a minimum 2.00:1.00 ratio of proved developed producing reserves to aggregate principal loan commitments under the New First Lien Exit Facility at any time after July 4, 2017.

If no default or event of default under the New First Lien Exit Facility exists at the expiration or termination of the Protected Period, all remaining proceeds in the Cash Collateral Account will be released to the Company at that time.

- Senior Secured Notes. All outstanding obligations under the 8.75% Senior Secured Notes due 2020 issued in June 2015 and the $78.0 million principal 8.75% Senior Secured Notes due 2020 issued to Piñon Gathering Company, LLC ("PGC) in October 2015, (the "PGC Senior Secured Notes") (collectively, "Senior Secured Notes") were canceled and exchanged for approximately 13.7 million of the 18.9 million shares of common stock in the Successor Company (the "New Common Stock") issued at emergence. Additionally, claims under the Senior Secured Notes received approximately $281.8 million principal amount of newly issued, non-interest bearing 0.00% convertible senior subordinated notes due 2020, (the “New Convertible Notes”), which are mandatorily convertible into approximately 15.0 million shares of New Common Stock upon the first to occur of several triggering events, one of which is refinancing of the New First Lien Exit Facility. Refer to Note 11 and Note 15 for additional information.

- General Unsecured Claims. The Company’s general unsecured claims, including the 8.75% Senior Notes due 2020, 7.5% Senior Notes due 2021, 8.125% Senior Notes due 2022, and 7.5% Senior Notes due 2023 (collectively, the “Senior Unsecured Notes”) and the 8.125% Convertible Senior Notes due 2022 and 7.5% Convertible Senior Notes due 2023 (collectively, the “Convertible Senior Unsecured Notes” and together with the Senior Unsecured Notes, the “Unsecured Notes”), became entitled to receive their proportionate share of (a) approximately $36.7 million in cash, (b) approximately 5.7 million shares of New Common Stock, 5.2 million of which was issued immediately upon emergence, and (c) 4.9 million Series A Warrants, 4.5 million issued immediately upon emergence, and 2.1 million Series B Warrants, 1.9 million issued immediately upon emergence, with initial exercise prices of $41.34 and $42.03 per share, respectively, which expire on October 4, 2022, (the "Warrants"). Refer to Note 11 and Note 15 for additional information.

- New Building Note. A note with a principal amount of $35.0 million, which is secured by first priority mortgages on the Company's headquarters facility and certain other non-oil and gas real property located in downtown Oklahoma City, Oklahoma (the "New Building Note") was issued and purchased on the emergence date for $26.8 million in cash, net of certain fees and expenses, by certain holders of the Unsecured Senior Notes. Refer to Note 11 for additional information.

- Preferred and Common Stock. The Company's existing 7.0% and 8.5% convertible perpetual preferred stock and common stock were canceled and released under the Plan without receiving any recovery on account thereof. Refer to Note 15 for additional information.

Additionally, pursuant to the Plan confirmed by the Bankruptcy Court, the Company's 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.

2. Fresh Start Accounting

Fresh Start Accounting. Upon emergence from bankruptcy, the Company applied fresh start accounting to its financial statements because (i) the holders of existing voting shares of the Company prior to its emergence received less than 50% of the voting shares of the Company outstanding following its emergence from bankruptcy and (ii) the reorganization value of the Company's assets immediately prior to confirmation of the plan of reorganization was less than the post-petition liabilities and allowed claims.

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 for the period 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.

Reorganization Value. Reorganization value represents the fair value of the Successor Company's total assets and is intended to approximate the amount a willing buyer would pay for the assets immediately after restructuring. Under fresh start accounting, the Company allocated the reorganization value to its individual assets based on their estimated fair values.

The Company's reorganization value is derived from an estimate of enterprise value. Enterprise value represents the estimated fair value of an entity's long term debt and other interest-bearing liabilities and shareholders' equity. In support of the Plan, the Company estimated the enterprise value of the Successor Company to be in the range of $1.04 billion to $1.32 billion, which was subsequently approved by the Bankruptcy Court. This valuation analysis was prepared using reserve information, development schedules, other financial information and financial projections, third-party real estate reports, and applying standard valuation techniques, including net asset value analysis, precedent transactions analyses and public comparable company analyses. Based on the estimates and assumptions used in determining the enterprise value, the Company estimated the enterprise value to be approximately $1.09 billion.

Valuation of Oil and Gas Properties. The Company’s principal assets are its oil and gas properties, which are accounted for under the Full Cost Accounting method as described in Note 3. With the assistance of valuation experts, the Company determined the fair value of its oil and gas properties based on the discounted cash flows expected to be generated from these assets. The computations were based on market conditions and reserves in place as of the bankruptcy emergence date.

The fair value analysis performed by valuation experts was based on the Company’s estimates of proved reserves as developed internally by the Company’s reserves engineers. Discounted cash flow models were prepared using the estimated future revenues and development and operating costs for all developed wells and undeveloped locations comprising the proved reserves. Future revenues were based upon forward strip oil and natural gas prices as of the emergence date, adjusted for differentials realized by the Company. Development and operating costs from proved reserves estimates were adjusted for inflation. A risk adjustment factor was applied to the proved undeveloped reserve category. The discounted cash flow models also included estimates not typically included in proved reserves such as depreciation and income tax expenses.

The risk adjusted after tax cash flows were discounted at 10%. This discount factor was derived from a weighted average cost of capital computation which utilized a blended expected cost of debt and expected returns on equity for similar industry participants.

From this analysis the Company concluded the fair value of its proved reserves was $632.8 million as of the Emergence Date. The Company also reviewed its undeveloped leasehold acreage and concluded that the fair value of undeveloped leasehold acreage was $113.9 million based on analysis of comparable market transactions. These amounts are reflected in the Fresh Start Adjustments item number 14 below.

The following table reconciles the enterprise value to the estimated fair value of the Successor Company's common stock as of the Emergence Date (in thousands, except per share amounts):

Enterprise value	$1,089,808
Plus: Cash and cash equivalents	563,372
Less: Fair value of New Building Note	(36,610)
Less: Asset retirement obligation	(92,412)
Less: Fair value of New First Lien Exit Facility	(414,954)
Less: Fair value of New Convertible Notes	(445,660)
Less: Fair value of warrants, including warrants held in reserve for settlement of general unsecured claims	(95,794)
Fair value of Successor common stock issued upon emergence	$567,750
Shares issued upon emergence on October 4, 2016, including shares held in reserve for settlement of general unsecured claims	19,371
Per share value	$29.31

The following table reconciles the enterprise value to the estimated reorganization value as of the Emergence Date (in thousands):

Enterprise value	$1,089,808
Plus: cash and cash equivalents	563,372
Plus: other working capital liabilities	131,766
Plus: other long-term liabilities	8,549
Reorganization value of Successor assets	$1,793,495

Reorganization value and enterprise value were estimated using numerous projections and assumptions that are inherently subject to significant uncertainties and resolution of contingencies that are beyond our control. Accordingly, the estimates included in this report are not necessarily indicative of actual outcomes, and there can be no assurance that the estimates, projections or assumptions will be realized.

Consolidated Balance Sheet. The adjustments included in the following consolidated balance sheet reflect the effects of the transactions contemplated by the Plan and carried out by the Company on the Emergence Date (reflected in the column “Reorganization Adjustments”) as well as fair value adjustments as a result of the adoption of fresh start accounting (reflected in the column “Fresh Start Adjustments”). The explanatory notes highlight methods used to determine fair values or other amounts of the assets and liabilities as well as significant assumptions.

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

The following table reflects the reorganization and application of Accounting Standards Codification ("ASC") 852 "Reorganizations" on the consolidated balance sheet as of October 1, 2016 (in thousands):

	Predecessor Company	Reorganization Adjustments		Fresh Start Adjustments		Successor Company
ASSETS						
Current assets						
Cash and cash equivalents	$652,680	$ (142,148	) (1)	$ —		$510,532
Restricted cash - collateral	—	50,000	(2)	—		50,000
Restricted cash - other	—	2,840	(2)	—		2,840
Accounts receivable, net	61,446	12,356	(3)	—		73,802
Derivative contracts	10,192	—		(669	) (12)	9,523
Prepaid expenses	12,514	(8,218	) (4)	—		4,296
Other current assets	1,003	—		3,217	(13)	4,220
Total current assets	737,835	(85,170	)	2,548		655,213
Oil and natural gas properties, using full cost method of accounting						
Proved	12,093,492	—		(11,344,684	) (14)	748,808
Unproved	322,580	—		(205,578	) (14)	117,002
Less: accumulated depreciation, depletion and impairment	(11,637,538)	—		11,637,538	(14)	—
	778,534	—		87,276		865,810
Other property, plant and equipment, net	357,528	(41	)	(93,782	) (15)	263,705
Derivative contracts	70	—		(70	) (12)	—
Other assets	12,537	(3,770	) (5)	—		8,767
Total assets	$1,886,504	$ (88,981	)	$ (4,028	)	$1,793,495

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

	Predecessor Company	Reorganization Adjustments		Fresh Start Adjustments		Successor Company
LIABILITIES AND STOCKHOLDERS' (DEFICIT) EQUITY						
Current liabilities						
Accounts payable and accrued expenses	$140,448	$ (14,820)	(6)	$ —		$125,628
Derivative contracts	2,982	—		1,666	(12)	4,648
Asset retirement obligations	8,573	—		57,105	(16)	65,678
Total current liabilities	152,003	(14,820)		58,771		195,954
Long-term debt	—	731,735	(7)	1,610	(17)	733,345
Derivative contracts	935	—		304	(12)	1,239
Asset retirement obligations	62,896	—		(36,161)	(16)	26,735
Other long-term obligations	3	8,798	(8)	(3)		8,798
Liabilities subject to compromise	4,346,188	(4,346,188)	(9)	—		—
Total liabilities	4,562,025	(3,620,475)		24,521		966,071
Equity						
SandRidge Energy, Inc. stockholders' equity (deficit)						
Predecessor preferred stock	6	—		(6)	(18)	—
Predecessor common stock	718	—		(718)	(18)	—
Predecessor additional paid-in capital	5,315,655	—		(5,315,655)	(18)	—
Predecessor additional paid-in capital—stockholder receivable	(1,250)	1,250	(10)	—		—
Predecessor treasury stock, at cost	(5,218)	—		5,218	(18)	—
Successor common stock	—	19	(11)	—		19
Successor warrants	—	88,382	(11)	—		88,382
Successor additional paid-in capital	—	739,023	(11)	—		739,023
Accumulated deficit	(7,985,411)	2,702,820	(9)	5,282,591	(19)	—
Total SandRidge Energy, Inc. stockholders' (deficit) equity	(2,675,500)	3,531,494		(28,570)		827,424
Noncontrolling interest	(21)	—		21	(20)	—
Total stockholders' (deficit) equity	(2,675,521)	3,531,494		(28,549)		827,424
Total liabilities and stockholders' equity (deficit)	$1,886,504	$ (88,981)		$ (4,028)		$1,793,495

Reorganization Adjustments

1. Reflects the net cash payments made upon emergence (in thousands):

Sources:	
Proceeds from New Building Note	$26,847
Total sources	$26,847
Uses and transfers:	
Cash transferred to restricted accounts (collateral and general unsecured claims)	$52,840
Payments and funding of escrow account related to professional fees	43,770
Payment on Senior Credit facility (principal and interest)	35,238
Repayment of Senior Secured Notes and Unsecured Notes	33,874
Payment of certain contract cures and other	3,273
Total uses and transfers	168,995

Net uses and transfers	$(142,148)

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

2. Funding of $50.0 million Cash Collateral account and the funding of $2.8 million to be held in reserve by the Company for distribution to satisfy allowed general unsecured claims as specified under the Plan.

3. Accrual for future reimbursement of the unused portion of the professional fees escrow account and other receivables.

4. Write-off of prepaid expenses primarily related to $7.5 million of prepaid premium for the Predecessor Company's directors and officers insurance policy.

5. Application of a $3.8 million deposit held by a utility service toward the settlement of the utility service's claims under the Plan.

6. Includes a $43.8 million decrease in accrued liabilities as a result of funding an escrow account established for the payment of professional fees, partially offset by the reinstatement of certain liabilities subject to compromise as accounts payable and accrued expenses.

7. Principal balances of $35.0 million of the New Building Note, $281.8 million of the New Convertible Notes, and the $415.0 million drawn on the New First Lien Exit Facility.

8. Reclassification of non-qualified deferred compensation plan and gas balancing liabilities from liabilities subject to compromise to other long term obligations, as these liabilities became obligations of the Successor.

9. Liabilities subject to compromise were settled as follows in accordance with the Plan (in thousands):

Current maturities of long-term debt and accrued interest	$4,179,483
Accounts payable and accrued expenses	157,422
Other long-term liabilities	9,283
Liabilities subject to compromise of the Predecessor	4,346,188
Cash payments at emergence	(72,385)
Cash proceeds from building mortgage	26,847
Write-off of prepaid accounts upon emergence	(8,218)
Accrual for future reimbursement from professional fees escrow account and other receivables	12,356
Total consideration given pursuant to the Plan:	
Fair value of equity issued	(827,424)
Principal value of long-term debt issued and reinstated at emergence	(731,735)
Reinstatement of liabilities subject to compromise as accounts payable and accrued expenses	(37,789)
Release of stockholder receivable	(1,250)
Application of deposit held by utility services	(3,770)
Gain on settlement of liabilities subject to compromise	$2,702,820

10. Release of a receivable from the Predecessor's former director and officer as outlined in the Plan.

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

11. The following table reconciles reorganization adjustments made to Successor common stock, warrants and additional paid in capital (in thousands):

Par value of 18.9 million shares of New Common Stock issued to former holders of the Senior Secured Notes and Unsecured Notes (valued at $29.31 per share)	$19
Fair value of warrants issued to holders of the Unsecured Notes(1)	88,382
Additional paid in capital - New Common Stock	575,144
Additional paid in capital - premium on New Convertible Notes(2)	163,879
Total Successor Company equity issued on Emergence Date	$827,424

(1) The fair value of the warrants was estimated using a Black-Scholes-Merton model with the following assumptions: implied stock price of the Successor Company; exercise price per share of $41.34 and $42.03 for Warrant classes A and B, respectively; expected volatility of 59.26%; risk free interest rate, continuously compounded, of 1.36%; and holding period of six years.

(2) The fair value of the New Convertible Notes was estimated using a Monte Carlo simulation with the following assumptions; the implied Successor Company stock price; expected volatility of 56.06%; risk free interest rate, continuously compounded, of 1.08%; recovery rate of 15.00%; hazard rate of 12.41%; drop on default of 100.00%; and termination period after four years. The premium is the difference between the fair value of the New Convertible Notes of $445.7 million and the principal value of the New Convertible Notes of $281.8 million.

Fresh Start Adjustments

12. Adjustments and reclassifications of derivative contracts based on their Emergence Date fair values, which were determined using the fair value methodology for commodity derivative contracts discussed in Note 6.

13. Fair value adjustment to other current assets to record assets held for sale at their anticipated sales prices.

14. Fair value adjustments to oil and natural gas properties, including asset retirement obligation, associated inventory, unproved acreage and seismic. See above for detailed discussion of fair value methodology.

15. Adjustments to other property, plant and equipment to record the assets at their respective fair values on the Emergence Date. A combination of the cost approach and income approach were utilized to determine the fair values of the Company’s headquarters and other properties located in downtown Oklahoma City, Oklahoma, and the cost approach was utilized to determine the fair value of all other property, plant and equipment.

16. Fair value adjustments to the Company’s asset retirement obligations as a result of applying fresh start accounting. Upon implementation of fresh start accounting, the Company revalued these obligations based upon updates to wells’ productive lives and application of the Successor Company’s credit adjusted risk fee rate.

17. Fair value adjustment to record premium on the New Building Note.

18. Cancellation of Predecessor Company’s common stock, preferred stock, treasury stock and paid-in capital.

19. Adjustment to reset retained deficit to zero.

20. Elimination of the Predecessor non-controlling interest.

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

Reorganization Items

Reorganization items represent liabilities settled, net of amounts incurred subsequent to the Chapter 11 filing as a direct result of the Plan and are classified as gain on reorganization items, net in the accompanying consolidated statement of operations. The following table summarizes reorganization items for the Predecessor 2016 Period (in thousands):

Unamortized long-term debt	$3,546,847
Litigation claims	(20,478)
Rejections and cures of executory contracts	(16,038)
Ad valorem and franchise taxes	(3,494)
Legal and professional fees and expenses	(44,920)
Write off of director and officer insurance policy	(7,533)
Gain on accounts payable settlements	84,228
Loss on mortgage	(8,153)
Gain on preferred stock dividends	37,893
Fresh start valuation adjustments	(28,549)
Fair value of equity issued	(827,424)
Principal value of New Convertible Notes issued	(281,780)
Gain on reorganization items, net	$2,430,599

3. Summary of Significant Accounting Policies

Fresh Start Accounting. Upon emergence from bankruptcy the Company adopted fresh start accounting. See Note 2 for further details.

Nature of Business. 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. Additionally, the Company owned interests in the Gulf of Mexico and Gulf Coast until February 2014, as discussed in Note 5.

Principles of Consolidation. The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern, which contemplates continuity of operations, realization of assets and satisfaction of liabilities in the normal course of business. The consolidated financial statements include the accounts of the Company and its wholly owned or majority owned subsidiaries. During the years ended December 31, 2015, and 2014, the Company fully consolidated the activities of each the SandRidge Mississippian Trust I (the “Mississippian Trust I”), SandRidge Mississippian Trust II (the “Mississippian Trust II”) and SandRidge Permian Trust (the “Permian Trust”) (each individually, a “Royalty Trust” and collectively, the “Royalty Trusts”) as variable interest entities (“VIEs”) for which the Company was the primary beneficiary. Activities of the Royalty Trusts attributable to third party ownership were presented as noncontrolling interest and included as a component of equity in the condensed consolidated balance sheet as of December 31, 2015. As discussed further below, during the year ended December 31, 2016, the Company proportionately consolidated the activities of the Royalty Trusts. All significant intercompany accounts and transactions have been eliminated in consolidation.

Reclassifications. Certain reclassifications have been made to the prior period financial statements to conform to the current period presentation. These reclassifications have no effect on the Company’s previously reported results of operations.

Use of Estimates. The preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

The more significant areas requiring the use of assumptions, judgments and estimates include: oil, natural gas and natural gas liquids (“NGL”) reserves; impairment tests of long-lived assets; depreciation, depletion and amortization; asset retirement obligations; determinations of significant alterations to the full cost pool and related estimates of fair value used to allocate the full cost pool net book value to divested properties, as necessary; income taxes; valuation of derivative instruments; contingencies; and accrued revenue and related receivables. Although management believes these estimates are reasonable, actual results could differ significantly.

Cash and Cash Equivalents. The Company considers all highly-liquid instruments with an original maturity of three months or less to be cash equivalents as these instruments are readily convertible to known amounts of cash and bear insignificant risk of changes in value due to their short maturity period.

Restricted Cash. The Company maintains restricted escrow funds as required by certain contractual arrangements in accordance with the Plan.

Accounts Receivable, Net. The Company has receivables for sales of oil, natural gas and NGLs, as well as receivables related to the exploration, production and treating services for oil and natural gas, which have a contractual maturity of one year or less. An allowance for doubtful accounts has been established based on management's review of the collectability of the receivables in light of historical experience, the nature and volume of the receivables and other subjective factors. Accounts receivable are charged against the allowance, upon approval by management, when they are deemed uncollectible. As part of fresh start accounting, the allowance for doubtful accounts was reset to zero on the Emergence Date. Refer to Note 7 for further information on the Company's accounts receivable and allowance for doubtful accounts.

Fair Value of Financial Instruments. Certain of the Company's financial assets and liabilities are measured at fair value. Fair value represents the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. The Company's financial instruments, not otherwise recorded at fair value, consist primarily of cash, trade receivables, trade payables and long-term debt. The carrying value of cash, trade receivables and trade payables are considered to be representative of their respective fair values due to the short-term maturity of these instruments. See Note 6 for further discussion of the Company's fair value measurements.

Fair Value of Non-financial Assets and Liabilities. The Company also applies fair value accounting guidance to initially, or as events dictate, measure non-financial assets and liabilities such as those obtained through business acquisitions, property, plant and equipment and asset retirement obligations. These assets and liabilities are subject to fair value adjustments only in certain circumstances and are not subject to recurring revaluations. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two as considered appropriate based on the circumstances. Under the discounted cash flow method, estimated future cash flows are based on management's expectations for the future and include estimates of future oil and natural gas production or other applicable sales estimates, operational costs and a risk-adjusted discount rate. The Company may use the present value of estimated future cash inflows and/or outflows or third-party offers or prices of comparable assets with consideration of current market conditions to value its non-financial assets and liabilities when circumstances dictate determining fair value is necessary. Fair value measurements for the electrical asset were based on replacement cost. Inputs used in the cost approach are based on the cost to a market participant buyer to acquire or construct a substitute asset of comparable utility, adjusted for inutility. Given the significance of the unobservable nature of a number of the inputs, these are considered Level 3 on the fair value hierarchy discussed in Note 6.

Derivative Financial Instruments. To manage risks related to fluctuations in prices attributable to its expected oil and natural gas production, the Company enters into oil and natural gas derivative contracts. Entrance into such contracts is dependent upon prevailing or anticipated market conditions. The Company may also, from time to time, enter into interest rate swaps in order to manage risk associated with its exposure to variable interest rates.

The Company recognizes its derivative instruments as either assets or liabilities at fair value with changes in fair value recognized in earnings unless designated as a hedging instrument with specific hedge accounting criteria having been met. The Company has elected not to designate price risk management activities as accounting hedges under applicable accounting guidance, and, accordingly, accounts for its commodity derivative contracts at fair value with changes in fair value reported currently in earnings. The Company nets derivative assets and liabilities whenever it has a legally enforceable master netting agreement with the counterparty to a derivative contract. The related cash flow impact of the Company's derivative activities are reflected as cash flows from operating activities unless the derivative contract contains a significant financing element, in which case, cash settlements are classified as cash flows from financing activities in the consolidated statements of cash flows. See Note 12 for further discussion of the Company's derivatives.

Oil and Natural Gas Operations. The Company uses the full cost method to account for its oil and natural gas properties. Under full cost accounting, all costs directly associated with the acquisition, exploration and development of oil, natural gas and NGL reserves are capitalized into a full cost pool. These capitalized costs include costs of unproved properties and internal costs directly related to the Company's acquisition, exploration and development activities and capitalized interest. The Company capitalized internal costs during the Successor 2016 Period of $4.0 million and the Predecessor Company capitalized internal costs of $22.7 million, $45.1 million and $55.4 million to the full cost pool during the Predecessor 2016 Period and the years ended December 31, 2015 and 2014, respectively. Capitalized costs are amortized using the unit-of-production method. Under this method, depreciation and depletion is computed at the end of each quarter by multiplying total production for the quarter by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base plus future development costs by net equivalent proved reserves at the beginning of the quarter.

Costs associated with unproved properties are excluded from the amortizable cost base until a determination has been made as to the existence of proved reserves. Unproved properties are reviewed at the end of each quarter to determine whether the costs incurred should be reclassified to the full cost pool and, thereby, subjected to amortization. The costs associated with unproved properties relate primarily to costs to acquire unproved acreage. Unproved leasehold costs are transferred to the amortization base with the costs of drilling the related well upon determination of the existence of proved reserves or upon impairment of a lease. All items classified as unproved property are assessed, on an individual basis or as a group if properties are individually insignificant, on a quarterly basis for possible impairment or reduction in value. The assessment includes consideration of various factors, including, but not limited to, the following: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; assignment of proved reserves; and economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, all or a portion of the associated leasehold costs are transferred to the full cost pool and become subject to amortization. Costs of seismic data are allocated to various unproved leaseholds and transferred to the amortization base with the associated leasehold costs on a specific project basis.

Under the full cost method of accounting, total capitalized costs of oil and natural gas properties, net of accumulated depreciation, depletion and impairment, less related deferred income taxes may not exceed an amount equal to the present value of future net revenues from proved reserves, discounted at 10% per annum, plus the lower of cost or fair value of unproved properties, plus estimated salvage value, less the related tax effects (the “ceiling limitation”). A ceiling limitation calculation is performed at the end of each quarter. If total capitalized costs, net of accumulated depreciation, depletion and impairment, less related deferred taxes are greater than the ceiling limitation, a write-down or impairment of the full cost pool is required. A write-down of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders’ equity in the period of occurrence and typically results in lower depreciation and depletion expense in future periods. Once incurred, a write-down cannot be reversed at a later date.

The ceiling limitation calculation is prepared using the 12-month oil and natural gas average price for the most recent 12 months as of the balance sheet date and as adjusted for basis or location differentials, held constant over the life of the reserves (“net wellhead prices”). If applicable, these net wellhead prices would be further adjusted to include the effects of any fixed price arrangements for the sale of oil and natural gas. Derivative contracts that qualify and are designated as cash flow hedges are included in estimated future cash flows, although the Company historically has not designated any of its derivative contracts as cash flow hedges and has therefore not included its derivative contracts in estimating future cash flows. The future cash outflows associated with future development or abandonment of wells are included in the computation of the discounted present value of future net revenues for purposes of the ceiling limitation calculation.

Sales and abandonments of oil and natural gas properties being amortized are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustments would significantly alter the relationship between capitalized costs and proved oil, natural gas and NGL reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the proved reserve quantities of a cost center.

Property, Plant and Equipment, Net. Other capitalized costs, including drilling equipment, natural gas gathering and treating equipment, electrical infrastructure, transportation equipment and other property and equipment are carried at cost. Renewals and improvements are capitalized while repairs and maintenance are expensed. Depreciation of such property and equipment is computed using the straight-line method over the estimated useful lives of the assets, which range from 10 to 39 years for buildings and 2 to 30 years for equipment. When property and equipment components are disposed, the cost and the related accumulated depreciation are removed and any resulting gain or loss is reflected in the consolidated statements of operations. As part of fresh start accounting, property, plant and equipment were adjusted to their estimated fair value and depreciable lives were revised as of October 1, 2016, as described in Note 2.

Realization of the carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying value of such asset may not be recoverable. Assets are considered to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset or asset group including disposal value, if any, is less than the carrying amount of the asset or asset group. Impairment is measured as the excess of the carrying amount of the impaired asset or asset group over its fair value. See Note 9 for further discussion of impairments.

Capitalized Interest. Interest is capitalized on assets being made ready for use using a weighted average interest rate based on the Company’s borrowings outstanding during that time. During the Predecessor 2016 Period and years ended December 31, 2015 and 2014, the Predecessor Company capitalized interest of approximately, $2.2 million, $10.8 million and $14.7 million, respectively, on unproved properties that were not currently being depreciated or depleted and on which exploration activities were in progress. Additionally, the Predecessor Company capitalized interest of $3.3 million and $5.0 million in 2015 and 2014, respectively, on midstream and corporate assets which were under construction.

Debt Issuance Costs. The Company includes unamortized line-of-credit debt issuance costs, if any, related to its credit facility in other assets in the consolidated balance sheets. Other debt issuance costs related to long-term debt, if any, are presented in the balance sheets as a direct deduction from the associated debt liability. Debt issuance costs are amortized to interest expense over the scheduled maturity period of the related debt. Upon retirement of debt, any unamortized costs are written off and included in the determination of the gain or loss on extinguishment of debt.

Investments. Investments in marketable equity securities relate primarily to the Company’s non-qualified deferred compensation plan, and have been designated as available for sale and measured at fair value using quoted prices readily available in the market pursuant to the fair value option which requires unrealized gains and losses be reported in earnings. Investments are included in other current assets and other assets in the accompanying consolidated balance sheets.

Asset Retirement Obligations. The Company owns oil and natural gas properties that require expenditures to plug, abandon and remediate wells at the end of their productive lives, in accordance with applicable federal and state laws. Liabilities for these asset retirement obligations are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired) at the estimated present value at the asset’s inception, with the offsetting increase to property cost. These property costs are depreciated on a unit-of-production basis within the full cost pool. The liability accretes each period until it is settled or the well is sold, at which time the liability is removed. Both the accretion and the depreciation are included in the consolidated statements of operations. The Company determines its asset retirement obligations by calculating the present value of estimated expenses related to the liability. Estimating future asset retirement obligations requires management to make estimates and judgments regarding timing, existence of a liability and what constitutes adequate restoration. Inherent in the present value calculation rates are the timing of settlement and changes in the legal, regulatory, environmental and political environments, which are subject to change. See Note 13 for further discussion of the Company’s asset retirement obligations. As part of fresh start accounting, the ARO liabilities were adjusted to their estimated fair value as described in Note 2.

Revenue Recognition and Natural Gas Balancing. Sales of oil, natural gas and NGLs are recorded when title of oil, natural gas and NGL production passes to the customer, net of royalties, discounts and allowances, as applicable. Additionally, the Successor Company has made an accounting policy election to deduct transportation costs from oil, natural gas and NGL revenues. This resulted in presenting $7.4 million of transportation costs as a reduction from revenues in the Successor 2016 Period versus the presentation of $26.2 million, $45.3 million and $35.6 million of these costs as production expenses in the Predecessor 2016 Period, and the years ended December 31, 2015 and 2014, respectively. and Taxes assessed by governmental authorities on oil, natural gas and NGL sales are presented separately from such revenues and included in production tax expense in the consolidated statements of operations.

The Company accounts for natural gas production imbalances using the sales method, whereby it recognizes revenue on all natural gas sold to its customers notwithstanding the fact that its ownership may be less than 100% of the natural gas sold. Liabilities are recorded for imbalances greater than the Company’s proportionate share of remaining estimated natural gas reserves. The Company has recorded a liability for natural gas imbalance positions related to natural gas properties with insufficient proved reserves of $1.7 million and $1.5 million at December 31, 2016 and 2015, respectively. The Company includes the gas imbalance positions in other long-term obligations in the consolidated balance sheets.

For the years ended December 31, 2015 and 2014, the Company recognized revenues and expenses generated from daywork and footage drilling contracts as the services were performed since the Company did not bear the risk of completion of the well. The Company received lump-sum fees for the mobilization of equipment and personnel. Mobilization fees received and costs incurred to mobilize a rig from one location to another were recognized at the time mobilization services were performed. Revenues and expenses related to drilling and services are included in other revenue and expense in the accompanying consolidated statements of operations for the years ended December 31, 2015 and 2014.

In general, natural gas purchased and sold by the midstream business was priced at a published daily or monthly index price. Sales to wholesale customers typically incorporated a premium for managing their transmission and balancing requirements. Midstream services revenues were recognized upon delivery of natural gas to customers and/or when services were rendered, pricing was determined and collectability was reasonably assured. Revenues from third-party midstream services were presented on a gross basis, since the Company acted as a principal by taking ownership of the natural gas purchased and taking responsibility of fulfillment for natural gas volumes sold. Revenues and expenses related to midstream and marketing are included in other revenue and expense in the accompanying consolidated statements of operations for the years ended December 31, 2015 and 2014.

Allocation of Share-Based Compensation. For both the Successor and Predecessor Companies, equity compensation provided to employees directly involved in exploration and development activities is capitalized to the Company’s oil and natural gas properties. Equity compensation not capitalized is recognized in general and administrative expenses, production expenses, and other operating expense in the accompanying consolidated statements of operations.
Income Taxes. Deferred income taxes reflect the net tax effects of temporary differences between the amounts of assets and liabilities reported for financial statement purposes and their tax basis. Deferred tax assets are reduced by a valuation allowance if it is deemed more likely than not that some or all of the deferred tax assets will not be realized.

The Company has elected an accounting policy in which interest and penalties on income taxes are presented as a component of the income tax provision, rather than as a component of interest expense. Interest and penalties resulting from the underpayment or the late payment of income taxes due to a taxing authority and interest and penalties accrued relating to income tax contingencies, if any, are presented, on a net of tax basis, as a component of the income tax provision.

Earnings per Share. Basic earnings per common share is calculated by dividing earnings available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per common share is calculated by dividing earnings available to common stockholders by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the Successor Company consist of unvested restricted stock awards and warrants, using the treasury method, and convertible senior notes, using the if-converted method. Potentially dilutive securities for the Predecessor Company consist of unvested restricted stock awards and restricted share units, using the treasury method, and convertible preferred stock and convertible senior notes, using the if-converted method.

Under the treasury method, the amount of unrecognized compensation expense related to unvested stock-based compensation grants or the proceeds that would be received if the warrants were exercised are assumed to be used to repurchase shares at the average market price.

Under the if-converted method, the Successor Company assumes the conversion of the New Convertible Notes to common stock and determines if it is more dilutive than including the expense associated with the New Convertible Notes in the computation of income available to common stockholders. Under the if-converted method, the Predecessor Company assumed the conversion of the preferred stock or Convertible Senior Unsecured Notes to common stock and determined if it was more dilutive than including the preferred stock dividends or expense associated with the Convertible Senior Unsecured Notes, respectively, in the computation of income available to common stockholders. When a loss exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share. See Note 19 for the Company’s earnings per share calculation.

Commitments and Contingencies. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Environmental expenditures are expensed or capitalized, as appropriate, depending on future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and costs can be reasonably estimated. See Note 14 for discussion of the Company’s commitments and contingencies.

Concentration of Risk. All of the Company’s commodity derivative transactions have been carried out in the over-the-counter market. The entry into derivative transactions in the over-the-counter market involves the risk that the counterparties may be unable to meet the financial terms of the transactions. The counterparties for all of the Company’s commodity derivative transactions have an “investment grade” credit rating. The Company monitors on an ongoing basis the credit ratings of its commodity derivative counterparties and considers its counterparties’ credit default risk ratings in determining the fair value of its commodity derivative contracts. The Company’s commodity derivative contracts are with multiple counterparties to minimize its exposure to any individual counterparty.

A default by the Company under its New First Lien Exit Facility constitutes a default under its commodity derivative contracts with counterparties that are lenders under the New First Lien Exit Facility. The Company does not require collateral or other security from counterparties to support commodity derivative instruments. The Company has master netting agreements with all of its commodity derivative counterparties, which allow the Company to net its commodity derivative assets and liabilities for like commodities and derivative instruments with the same counterparty. As a result of the netting provisions, the Company’s maximum amount of loss under commodity derivative transactions due to credit risk is limited to the net amounts due from the counterparties under the commodity derivative contracts. The Company’s loss is further limited as any amounts due from a defaulting counterparty that is a lender under the First Lien Exit Facility can be offset against amounts owed, if any, to such counterparty under the Company’s First Lien Exit facility.

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

The Company operates a substantial portion of its oil and natural gas properties. As the operator of a property, the Company makes full payment for costs associated with the property and seeks reimbursement from the other working interest owners in the property for their share of those costs. The Company's joint interest partners consist primarily of independent oil and natural gas producers. If the oil and natural gas exploration and production industry in general was adversely affected, the ability of the joint interest partners to reimburse the Company could be adversely affected.

The purchasers of the Company's oil, natural gas and NGL production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. The Company believes alternate purchasers are available in its areas of operations and does not believe the loss of any one purchaser would materially affect the Company's ability to sell the oil, natural gas and NGLs it produces.

The Company had sales exceeding 10% of total revenues to the following oil and natural gas purchasers (in thousands):

	Sales	% of Revenue
Period from October 2, 2016 through December 31, 2016 - Successor		
Targa Pipeline Mid-Continent West OK LLC	$35,845	36.4 %
Plains Marketing, L.P.	$32,022	32.5 %
Period from January 1, 2016 through October 1, 2016 - Predecessor		
Plains Marketing, L.P.	$110,370	37.6 %
Targa Pipeline Mid-Continent West OK LLC	$108,238	36.8 %
December 31, 2015 - Predecessor		
Plains Marketing, L.P.	$318,018	41.4 %
Targa Pipeline Mid-Continent West OK LLC	$231,649	30.1 %
December 31, 2014 - Predecessor		
Plains Marketing, L.P.	$597,117	38.3 %
Targa Pipeline Mid-Continent West OK LLC	$333,027	21.4 %

Recent Accounting Pronouncements. The Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update ("ASU") 2015-02, "Amendments to the Consolidation Analysis," which simplifies and improves current guidance by placing more emphasis on risk of loss when determining a controlling financial interest and reducing the frequency of the application of related-party guidance when determining a controlling financial interest in a VIE. The requirements of the guidance were effective for annual reporting periods beginning January 1, 2016 for the Company, including interim periods within that reporting period, with early adoption permitted. The Company adopted this guidance on January 1, 2016, which resulted in the determination that the Royalty Trusts no longer qualify as VIEs. As a result, the Successor and Predecessor Companies proportionately consolidated the activities of the Royalty Trusts in 2016. Under the proportionate consolidation method, the Company accounts for only its share of each Royalty Trust's asset, liabilities, revenues and expenses within the appropriate classifications in the accompanying consolidated financial statements. The Company adopted the provisions of ASU 2015-02 on a modified retrospective approach by recording a cumulative-effect adjustment as of January 1, 2016 that resulted in decreases of approximately $243.4 million to total assets and approximately $510.2 million to noncontrolling interest and increases of approximately $9.7 million to accounts payable and approximately $257.1 million to retained earnings. These adjustments had no impact on prior period balances.

The FASB issued ASU 2015-03, "Interest-Imputation of Interest (Topic 835): Simplifying the Presentation of Debt Issuance Costs," which requires debt issuance costs related to a recognized debt liability to be presented on the balance sheet as a direct deduction from the carrying amount of that debt liability rather than as an asset. The guidance was adopted on January 1, 2016, and resulted in a decrease of approximately $69.1 million to other assets and current maturities of long-term debt in the accompanying consolidated balance sheet for the year ended December 31, 2015, with no impact to the accompanying consolidated statements of operations. See Note 11 for treatment and classification of unamortized debt issuance costs subsequent to filing the Chapter 11 petitions. In August 2015, the FASB issued ASU 2015-15, “Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements,” which excludes line-of-credit debt issuance costs from the scope of ASU 2015-03. The guidance was adopted on January 1, 2016 in conjunction with the adoption of ASU 2015-03. The Company made

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

an accounting policy election to present line-of-credit arrangement debt issuance costs as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the line-of-credit arrangement. The adoption of this ASU resulted in no impact to the consolidated financial statements.

The FASB issued ASU 2014-15, “Presentation of Financial Statements - Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity’s Ability to Continue as a Going Concern,” which provides guidance on determining when and how to disclose going-concern uncertainties in the financial statements. The standard requires management to perform interim and annual assessments of an entity’s ability to continue as a going concern within one year of the date the financial statements are issued. An entity must provide certain disclosures if conditions or events raise substantial doubt about the entity’s ability to continue as a going concern. The Company adopted the provisions of this ASU for the year ended December 31, 2016 on a prospective basis. The adoption of this ASU had no impact to the Company’s disclosures included in this report.

The FASB issued ASU 2016-06, “Derivatives and Hedging (Topic 815): Contingent Put and Call Options in Debt Instruments” which eliminates diversity in practice in assessing embedded contingent call (put) options in debt instruments. The ASU requires adoption by application of a modified retrospective approach to existing and future debt instruments. The ASU is effective for the Company beginning January 1, 2017, with early adoption permitted. The Company early adopted the provisions of this ASU on the Emergence Date. The adoption of this ASU resulted in no impact to the consolidated financial statements and related disclosures.

The FASB issued ASU 2016-09, “Compensation - Stock Compensation (Topic 718): Improvements to Share-Based Payment Accounting” which was part of the FASB simplification initiative and involves several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The guidance requires adoption by various application methods, effective for the Company beginning January 1, 2017. The Company early adopted all provisions of this ASU on the Emergence Date. Upon adoption, the Company made an accounting policy election to account for forfeitures as they occur. The adoption of this ASU resulted in no impact to the consolidated financial statements and related disclosures.

The FASB issued ASU 2016-18, “Statement of Cash Flows (Topic 230): Restricted Cash” to require inclusion of amounts generally described as restricted cash or restricted cash equivalents when reconciling the beginning of period and end of period total amounts shown on the statement of cash flows. This ASU is effective for the Company beginning January 1, 2018. The Company early adopted the provisions of this ASU on December 31, 2016, using a retrospective transition method for each period presented. As a result of the adoption, the Company included $52.8 million of restricted cash in the beginning of period and end of period total amounts shown on the Successor statement of cash flows for October 2, 2016 and December 31, 2016, respectively. There was no impact to the Predecessor statement of cash flows.

Recent Accounting Pronouncements Not Yet Adopted. The FASB issued ASU 2014-09, “Revenue from Contracts with Customers (Topic 606),” which provides guidance concerning the recognition and measurement of revenue from contracts with customers. Its objective is to increase the usefulness of information in the financial statements regarding the nature, timing and uncertainty of revenues. In August 2015, the FASB issued ASU 2015-14, "Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date," which defers the effective date of ASU 2014-09 to January 1, 2018 for the Company, with early adoption permitted in 2017. The ASU must be adopted using either the retrospective transition method, which requires restating previously reported results or the cumulative effect (modified retrospective) transition method, which utilizes a cumulative-effect adjustment to retained earnings in the period of adoption to account for prior period effects rather than restating previously reported results. The Company does not plan to early adopt and is currently evaluating the effect that the updated standard will have on its consolidated financial statements and related disclosures.

The FASB issued ASU 2016-02, “Leases (Topic 842),” which requires companies to recognize the assets and liabilities for the rights and obligations created by long-term leases of assets on the balance sheet. The guidance requires adoption by application of a modified retrospective transition approach for existing long-term leases and is effective for the Company on January 1, 2019. Early adoption is permitted. The Company does not plan to early adopt and is currently evaluating the effect that the guidance will have on its consolidated financial statements and related disclosures.

The FASB issued ASU 2016-15, “Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments” with the objective of reducing the existing diversity in practice of classification on certain cash receipts and payments in the statement of cash flows. The guidance requires adoption by application of a retrospective method to each period presented. The amendments are effective for the Company on January 1, 2018, with early adoption permitted. The Company is currently evaluating the effect that the guidance will have on its consolidated financial statements.

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

The FASB issued ASU 2016-16, “Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other than Inventory” which removes the prohibition in ASC 740 against the immediate recognition of current and deferred income tax effects of intra-entity transfers of assets other than inventory. The amendments in this ASU are effective for the Company on January 1, 2018, with early adoption permitted on January 1, 2017. The ASU should be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. The Company does not plan to early adopt and is currently evaluating the effect that the guidance will have on its consolidated financial statements.

The FASB Issued ASU 2017-01, “Business Combinations (Topic 805): Clarifying the Definition of a Business,” which provides more consistency in applying the guidance, reduces the costs of application, and makes the definition of a business more operable. The ASU is effective for the Company on January 1, 2018 and amendments should be applied prospectively on and after January 1, 2018. Due to the prospective nature of the ASU, the Company cannot evaluate the impact to its consolidated financial statements until after adoption, and no disclosures are required upon transition.

4. Supplemental Cash Flow Information

Supplemental disclosures to the consolidated statements of cash flows are presented below (in thousands):

	Successor Period from October 2, 2016 through December 31, 2016	Predecessor Period from January 1, 2016 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Supplemental Disclosure of Cash Flow Information				
Cash paid for reorganization items	$—	$(55,606)	$—	$—
Cash paid for interest, net of amounts capitalized	$(1,183)	$(104,609)	$(296,386)	$(235,793)
Cash (paid) received for income taxes	$—	$(28)	$(88)	$1,928
Supplemental Disclosure of Noncash Investing and Financing Activities				
Cumulative effect of adoption of ASU 2015-02	$—	$(247,566)	$—	$—
Property, plant and equipment transferred in settlement of contract	$—	$215,635	$—	$—
Change in accrued capital expenditures	$10,630	$25,045	$177,586	$(55,557)
Equity issued for debt	$(13,001)	$(4,409)	$(63,299)	$—
Preferred stock dividends paid in common stock	$—	$—	$(16,188)	$—
Long-term debt issued, including derivative and net of discount, for asset acquisition and termination of gathering agreement	$—	$—	$(50,310)	$—

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

5. Acquisitions and Divestitures

Predecessor Acquisitions and Divestitures

2016 Divestiture

Divestiture of West Texas Overthrust Properties and Release from Treating Agreement. On January 21, 2016, the Company paid $11.0 million in cash and transferred ownership of substantially all of its oil and natural gas properties and midstream assets located in the Piñon field in the West Texas Overthrust ("WTO") to Occidental Petroleum Corporation ("Occidental") and was released from all past, current and future claims and obligations under an existing 30 year treating agreement between the companies. As of the date of the transaction, the Company had accrued approximately $111.9 million for penalties associated with shortfalls in meeting its delivery requirements under the agreement since it became effective in late 2012. The Company recognized a loss of approximately $89.1 million on the termination of the treating agreement and the cease-use of transportation agreements that supported production from the Piñon field and reduced its asset retirement obligations associated with its oil and natural gas properties by $34.1 million.

2015 Acquisitions

Acquisition of Piñon Gathering Company, LLC. In October 2015, the Company acquired all of the assets of and terminated a gathering agreement with PGC for $48.0 million in cash and $78.0 million principal amount of newly issued 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. The transaction resulted in the termination of the Company's gas gathering agreement with PGC under which it was required to compensate PGC for any throughput shortfalls below a required minimum volume. The fair value of the consideration paid by the Company, including discount attributable to the PGC Senior Secured Notes, was approximately $98.3 million and was allocated on a fair value basis between the assets acquired (approximately $47.3 million) and a loss on the termination of the gathering contract (approximately $51.0 million).

Acquisition of Rockies Properties. In December 2015, the Company acquired approximately 135,000 net acres in the North Park Basin in the Rockies, in Jackson County, Colorado. The Company paid approximately $191.1 million in cash, including post-closing adjustments, and received $3.1 million from the seller for overriding royalty interests. Also included in the acquisition were working interests in 16 wells previously drilled on the acreage.

2014 Divestiture

Sale of Gulf of Mexico and Gulf Coast Properties. On February 25, 2014, the Company sold subsidiaries that owned the Company's Gulf of Mexico and Gulf Coast oil and natural gas properties (collectively, the "Gulf Properties") for approximately $702.6 million, net of working capital adjustments and post-closing adjustments, and the buyer's assumption of approximately $366.0 million of related asset retirement obligations to Fieldwood Energy, LLC ("Fieldwood"). This transaction did not result in a significant alteration of the relationship between the Company's capitalized costs and proved reserves and, accordingly, the Company recorded the proceeds as a reduction of its full cost pool with no gain or loss on the sale. See Note 20 for discussion of Fieldwood's related party affiliation with the Company.

In accordance with the terms of the sale, the Company agreed to guarantee on behalf of Fieldwood certain plugging and abandonment obligations associated with the Gulf Properties for a period of up to one year from the date of closing. The Company recorded a liability equal to the fair value of these guarantees, or $9.4 million, at the time the transaction closed. See Note 6 for additional discussion of the determination of the guarantee’s fair value. The guarantee did not limit the Company’s potential future payment obligations; however, Fieldwood agreed to indemnify the Company for any costs it incurred as a result of the guarantee and to use its best efforts to pay any amounts sought from the Company by the Bureau of Ocean Energy Management (“BOEM”) that arose prior to the expiration of the guarantee. The Company did not incur any costs as a result of this guarantee and was released from the obligation during the third quarter of 2015. Additionally, Fieldwood maintained, for a period of up to one year from the closing date, restricted deposits held in escrow for plugging and abandonment obligations associated with the Gulf Properties. In the first quarter of 2015, the Company received its share of such deposits, net of any amounts payable to Fieldwood, or $12.0 million, in accordance with the terms of the sale.

The company recorded revenues and expenses of $90.9 million and $63.7 million, respectively, through the date of the sale, including direct operating expenses, depletion, accretion of asset retirement obligations and general and administrative expenses, for the Gulf Properties which are included in the Predecessor Company’s accompanying consolidated statement of operations for the year ended December 31, 2014.

6. Fair Value Measurements

The Company measures and reports certain assets and liabilities on a fair value basis and has classified and disclosed its fair value measurements using the following levels of the fair value hierarchy:

Level 1	Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities.
Level 2	Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.
Level 3	Measurement based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable for objective sources (i.e., supported by little or no market activity).

Assets and liabilities that are measured at fair value are classified based on the lowest level of input that is significant to the fair value measurement. The Company’s assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values, stated below, considers the market for the Company’s financial assets and liabilities, the associated credit risk and other factors. The Company considers active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis. The Company has assets and liabilities classified in each level of the hierarchy as of December 31, 2016 and 2015, as described below.

Level 1 Fair Value Measurements

Investments. The fair value of investments, consisting of assets attributable to the Company’s non-qualified deferred compensation plan, is based on quoted market prices. Investments are included in other current assets and other assets in the accompanying consolidated balance sheets.

Level 2 Fair Value Measurements

Commodity Derivative Contracts. The fair values of the Company’s oil and natural gas fixed price swaps are based upon inputs that are either readily available in the public market, such as oil and natural gas futures prices, volatility factors and discount rates, or can be corroborated from active markets. Fair value is determined through the use of a discounted cash flow model or option pricing model using the applicable inputs, discussed above. The Company applies a weighted average credit default risk rating factor for its counterparties or gives effect to its credit default risk rating, as applicable, in determining the fair value of these derivative contracts. Credit default risk ratings are based on current published credit default swap rates.

Mandatory Prepayment Feature - PGC Senior Secured Notes. In conjunction with the acquisition of and termination of a gathering agreement with PGC in October 2015, the Company issued the PGC Senior Secured Notes as discussed in Note 5. The PGC Senior Secured Notes were issued at a substantial discount, as discussed in Note 11 and Note 12, which resulted in the treatment of the mandatory prepayment feature as an embedded derivative that met the criteria to be bifurcated from its host contract and accounted for separately from the PGC Senior Secured Notes. Prior to Chapter 11 filings, the mandatory prepayment feature was recorded at fair value each reporting period based upon values determined through the use of discounted cash flow models of the PGC Senior Secured Notes both (i) with the mandatory prepayment feature and (ii) excluding the mandatory prepayment feature. Subsequent to the Chapter 11 filings in May 2016, the value of the mandatory repayment feature of $2.5 million was written off and is included in reorganization items in the accompanying consolidated statement of operations for the Predecessor 2016 Period.

Level 3 Fair Value Measurements

Commodity Derivative Contracts. The Company had natural gas basis swaps outstanding on the Emergence Date and at December 31, 2015 and 2014. The fair value of the natural gas basis swaps was based upon quotes obtained from counterparties to the derivative contracts. These values were reviewed internally for reasonableness through the use of a discounted cash flow model using non-exchange traded regional pricing information. Additionally, the Company applied a weighted average credit default risk rating factor for its counterparties or gave effect to its credit risk, as applicable, in determining the fair value of the commodity derivative contracts. The significant unobservable input that was used in the fair value measurement of the Company's natural gas basis swaps was the estimate of future natural gas basis differentials. The fair value of the natural gas basis swaps and any purchases, gains/losses and settlements were insignificant for the Predecessor 2016 Period and for the years ended December 31, 2015 and 2014. No natural gas basis swaps were outstanding at December 31 2016.

Debt Holder Conversion Feature. The Predecessor Company's Convertible Senior Unsecured Notes each contained a conversion option whereby, prior to Chapter 11 filings, the Convertible Senior Unsecured Notes holders had the option to convert the notes into shares of Company common stock. These conversion features were identified as embedded derivatives that met the criteria to be bifurcated from their host contracts and accounted for separately from the Convertible Senior Unsecured Notes. Subsequent to the Chapter 11 filings, the value of the debt holder conversion feature of $7.3 million was written off and is included in reorganization items in the accompanying statement of operations for the Predecessor 2016 Period.

The fair values of the holder conversion features were determined using a binomial lattice model based on certain assumptions including (i) the Company's stock price, (ii) risk-free rate, (iii) recovery rate, (iv) hazard rate and (v) expected volatility. The significant unobservable input used in the fair value measurement of the conversion features was the hazard rate, an estimate of default probability. The significant unobservable inputs and range and weighted average of these inputs used in the fair value measurement of the conversion features at December 31, 2015 are included in the table below.

Unobservable Input	Range	Weighted Average	Fair Value
			(In thousands)
Debt conversion feature hazard rate	114.0%-135.2%	119.2 %	$ 29,355

See further discussion of the Convertible Senior Unsecured Notes at Note 11.

Guarantee. The Company guaranteed on behalf of Fieldwood certain plugging and abandonment obligations associated with the sale of its Gulf Properties from the date of closing until the Company was released from the guarantee in the third quarter of 2015. The significant unobservable input used in the fair value measurement of the guarantees was the estimate of future payments for plugging and abandonment of approximately $372.0 million, which was developed based upon third-party quotes and then-current actual costs. While in effect, the fair value of the guarantee was determined quarterly with changes in fair value recorded as an adjustment to the full cost pool. See Note 5 for discussion of the sale of the Gulf Properties. The fair value of the guarantee and any issuances and settlements were insignificant for the year ended December 31, 2014.

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

Fair Value - Recurring Measurement Basis

The following tables summarize the Company's assets and liabilities measured at fair value on a recurring basis by the fair value hierarchy (in thousands):

December 31, 2016 - Successor

	Fair Value Measurements Level 1	Level 2	Level 3	Netting(1)	Assets/Liabilities at Fair Value
Assets					
Investments	$7,541	$—	$ —	$ —	$ 7,541
	$7,541	$—	$ —	$ —	$ 7,541
Liabilities					
Commodity derivative contracts	$—	$29,714	$ —	$ —	$ 29,714
	$—	$29,714	$ —	$ —	$ 29,714

December 31, 2015 - Predecessor

	Fair Value Measurements Level 1	Level 2	Level 3	Netting(1)	Assets/Liabilities at Fair Value
Assets					
Commodity derivative contracts	$—	$85,524	$—	$(1,175)	$ 84,349
Investments	10,106	—	—	—	10,106
	$10,106	$85,524	$—	$(1,175)	$ 94,455
Liabilities					
Commodity derivative contracts	$—	$—	$1,748	$(1,175)	$ 573
Debt holder conversion feature	—	—	29,355	—	29,355
Mandatory prepayment feature - PGC Senior Secured Notes	—	2,941	—	—	2,941
	$—	$2,941	$31,103	$(1,175)	$ 32,869

(1)Represents the impact of netting assets and liabilities with counterparties where the right of offset exists.

Level 3 - Debt Holder Conversion Feature. The table below sets forth a reconciliation of the Company's Level 3 fair value measurements for debt holder conversion features (in thousands):

	Predecessor Period from January 1, 2016 through October 1, 2016	Year Ended December 31, 2015
Beginning balance	$29,355	$—
Issuances	—	31,200
(Loss) gain on derivative holder conversion feature	(880)	10,198
Conversions	(21,194)	(12,043)

Write off of derivative holder conversion feature to reorganization items	(7,281)	—
Ending level 3 debt holder conversion feature balance	$—	$ 29,355

Prior to commencement of the Chapter 11 Proceedings, the fair values of the conversion features were determined quarterly with changes in fair value recorded as interest expense.

Transfers. The Company recognizes transfers between fair value hierarchy levels as of the end of the reporting period in which the event or change in circumstances causing the transfer occurred. During the years ended December 31, 2016, 2015 and 2014, the Company did not have any transfers between Level 1, Level 2 or Level 3 fair value measurements.

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

Fair Value of Financial Instruments - Long-Term Debt

The Successor Company measures the fair value of its New Convertible Notes using pricing that was readily available in the public market at December 31, 2016. The Successor Company measures the fair value of its New Building Note using a discounted cash flow analysis. The Predecessor Company also measured the fair value of its Senior Secured Notes and the Unsecured Notes using pricing that was readily available in the public market. The Company classifies these inputs as Level 2 in the fair value hierarchy. The estimated fair values and carrying values of the Company's notes are as follows (in thousands):

	Successor December 31, 2016		Predecessor December 31, 2015	
	Fair Value	Carrying Value	Fair Value	Carrying Value
New Convertible Notes	$334,800	$ 268,780	$—	$ —
New Building Note	$40,608	$ 36,528	$—	$ —
8.75% Senior Secured Notes due 2020	$—	$ —	$403,098	$ 1,265,814
Senior Unsecured Notes				
8.75% Senior Notes due 2020	$—	$ —	$39,740	$ 389,232
7.5% Senior Notes due 2021	$—	$ —	$79,812	$ 751,087
8.125% Senior Notes due 2022	$—	$ —	$57,749	$ 518,693
7.5% Senior Notes due 2023	$—	$ —	$58,799	534,869
Convertible Senior Unsecured Notes				
8.125% Convertible Senior Notes due 2022	$—	$ —	$44,199	$ 78,290
7.5% Convertible Senior Notes due 2023	$—	$ —	$15,125	$ 24,393

See Note 1 for additional information regarding the bankruptcy proceedings and Note 11 for discussion of the Company's long-term debt.

Fair Value of Non-Financial Assets and Liabilities

See Note 2 for additional information regarding fair value adjustments for non-financial assets and liabilities resulting from the application of fresh start accounting and Note 9 for discussion of the Company's impairment valuations.

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

7. Accounts Receivable

A summary of accounts receivable is as follows (in thousands):

	Successor December 31, 2016	Predecessor December 31, 2015
Oil, natural gas and NGL sales	$ 42,631	$ 61,140
Joint interest billing	17,338	60,403
Oil and natural gas services	736	2,417
Other	14,272	8,274
Total accounts receivable	74,977	132,234
Less: allowance for doubtful accounts	(880)	(4,847)
Total accounts receivable, net	$ 74,097	$ 127,387

The following table presents the balance and activity in the allowance for doubtful accounts for the Successor 2016 Period, the Predecessor 2016 Period and years ended December 31, 2015 and 2014 (in thousands):

	Successor	Predecessor		
	Period from October 2, 2016 through December 31, 2016	Period from January 1, 2016 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Beginning balance	$ —	$ 4,847	$ 7,083	$ 11,061
Additions charged to costs and expenses(1)	880	16,695	1,320	818
Deductions(2)	—	(751)	(3,556)	(4,796)
Impact of fresh start accounting	—	(20,791)	—	—
Ending balance	$ 880	$ —	$ 4,847	$ 7,083

(1) The Predecessor 2016 Period includes an addition for a joint interest account receivable after a determination that future collection was doubtful.

(2) Deductions represent write-off of receivables and collections of amounts for which an allowance had previously been established. Deductions in 2015 are primarily due to the write-off of receivables in conjunction with a lawsuit settlement and deductions in 2014 are related to the sale of the Gulf Properties.

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

8. Property, Plant and Equipment

Property, plant and equipment consists of the following (in thousands):

	Successor December 31, 2016	Predecessor December 31, 2015
Oil and natural gas properties		
Proved(1)	$840,201	$12,529,681
Unproved	74,937	363,149
Total oil and natural gas properties	915,138	12,892,830
Less accumulated depreciation, depletion and impairment	(353,030)	(11,149,888)
Net oil and natural gas properties capitalized costs	562,108	1,742,942
Land	5,100	14,260
Non-oil and natural gas equipment(2)	166,010	373,687
Buildings and structures(3)	88,603	227,673
Total	259,713	615,620
Less accumulated depreciation and amortization	(3,889)	(123,860)
Other property, plant and equipment, net	255,824	491,760
Total property, plant and equipment, net	$817,932	$2,234,702

(1) No interest was capitalized for the Successor 2016 Period. Includes cumulative capitalized interest of approximately $48.9 million at December 31, 2015.
(2) No interest was capitalized for the Successor 2016 Period. Includes cumulative capitalized interest of approximately $4.3 million at December 31, 2015.
(3) No interest was capitalized for the Successor 2016 Period. Includes cumulative capitalized interest of approximately $20.4 million at December 31, 2015.

In connection with the application of fresh start accounting as of October 1, 2016, the Company recorded fair value adjustments disclosed in Note 2. Accumulated depreciation, depletion and impairment was therefore eliminated as of that date.

Accumulated depreciation, depletion and impairment for the Predecessor Company oil and natural gas properties includes cumulative full cost ceiling limitation impairment of $8.2 billion at December 31, 2015.

During the Successor 2016 Period the Successor Company reduced the net carrying value of its oil and natural gas properties by $319.1 million and for the Predecessor 2016 Period, the Predecessor Company reduced the net carrying value of its oil and natural gas properties by $657.4 million, as a result of quarterly full cost ceiling analyses in the respective periods. The Company reduced the net carrying value of its oil and natural gas properties by $4.5 billion and $164.8 million during the years ended December 31, 2015 and 2014, respectively. See Note 9 for discussion of impairment of other property, plant and equipment.

The average rates used for depreciation and depletion of oil and natural gas properties were $7.82 per Boe for the Successor 2016 Period, $5.76 per Boe for the Predecessor 2016 Period, $10.67 per Boe in 2015 and $15.00 per Boe in 2014.

During the second and fourth quarters of 2015, the Company classified drilling and oilfield services assets having net book values of approximately $20.0 million and $16.0 million, respectively, as held for sale as a result of the

Company’s decisions to discontinue substantially all drilling and oilfield services operations first in the Permian region and then companywide. A portion of these assets were disposed of during the third quarter of 2015, resulting in a loss recorded in other operating expenses in the accompanying consolidated statement of operations of $3.5 million for the year ended December 31, 2015.

The remaining $16.0 million in assets held for sale at December 31, 2015 were sold during 2016, resulting in insignificant (loss) gain on sale of assets recorded for the Successor 2016 period and the Predecessor 2016 period. No significant assets were classified as held for sale at December 31, 2016.

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

Drilling Carry Commitments

During the year ended December 31, 2014, the Company was party to an agreement with Repsol E&P USA, Inc. (“Repsol”), which contained a carry commitment to fund a portion of its future drilling, completing and equipping costs within areas of mutual interest. The Company recorded approximately $205.6 million for Repsol’s carry during the year ended December 31, 2014, which reduced the Company’s capital expenditures for the respective periods. Repsol fully funded its carry commitment in the third quarter of 2014.

Under the terms of an amended agreement with Repsol, the Company committed to drill 484 net wells in an area of mutual interest and to carry Repsol’s future drilling and completion costs in the amount of $1.0 million for each committed well that it did not drill, up to a maximum of $75.0 million in carry costs. As of May 31, 2015, the Company had drilled 453 net wells under this arrangement and as a result, the Company was obligated under the agreement to carry a portion of Repsol’s drilling and completion costs totaling up to approximately $31.0 million for wells drilled after that time in the area of mutual interest. The Company incurred approximately $6.2 million and $16.1 million in costs toward this obligation for the Predecessor 2016 Period and the year ended December 31, 2015, respectively. Effective June 6, 2016, the Bankruptcy Court issued orders allowing the Company to reject certain long-term contracts, including this drilling carry commitment. Repsol filed a bankruptcy claim for this commitment, which was settled by the Company for approximately $1.2 million.

Costs Excluded from Amortization

The following table summarizes the costs, by year incurred, related to unproved properties and pipe inventory, which were excluded from oil and natural gas properties subject to amortization at December 31, 2016 (in thousands):

		Year Cost Incurred			
	Total	2016	2015	2014	2013 and Prior
Property acquisition	$71,171	$7,390	$18,959	$34,770	$ 10,052
Exploration(1)	20,459	2,123	10,578	4,678	3,080
Total costs incurred	$91,630	$9,513	$29,537	$39,448	$ 13,132

(1) Includes $16.7 million of pipe inventory costs incurred ($2.1 million in 2016, $9.6 million in 2015 and $5.0 million in 2014 and prior years).

The Company expects to complete the majority of the evaluation activities within 10 years from the applicable date of acquisition, contingent on the Company’s capital expenditures and drilling program. In addition, the Company’s internal engineers evaluate all properties on at least an annual basis.

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

9. Impairment

As deemed necessary based on events in 2016, 2015 and 2014, the Company analyzed various property, plant and equipment for impairment by comparing the carrying values of these assets to their estimated fair values. Estimated fair values of drilling, midstream, electrical transmission and other assets were determined in accordance with the policies discussed in Note 3.

Impairment consists of the following (in thousands):

	Successor	Predecessor		
	Period from October 2, 2016 through December 31, 2016	Period from January 1, 2016 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Full cost pool ceiling limitation(1)(2)(3)	$ 319,087	$ 657,392	$ 4,473,787	$ 164,779
Drilling assets(4)	—	3,511	37,646	27,428
Electrical transmission assets(5)	—	55,600	—	—
Midstream assets(6)	—	1,691	7,148	561
Other(7)	—	—	16,108	—
	$ 319,087	$ 718,194	$ 4,534,689	$ 192,768

(1) Impairment recorded in the Successor 2016 Period resulted from the application of fresh start accounting. Upon the application of fresh start accounting, the value of the Successor Company full cost pool was determined based upon forward strip oil and natural gas prices as of the Emergence Date. Because these prices were higher than the 12-month weighted average prices used in the full cost ceiling limitation calculation at December 31, 2016, the Successor Company incurred a ceiling test impairment.

(2) Impairment recorded for the Predecessor Company in 2016 was due to full cost ceiling limitations recognized in each of the first three quarters of 2016. The impairments recorded in 2015 and the first two quarters of 2016 resulted primarily from the significant decrease in oil prices, and to a lesser extent, natural gas prices, that began in the latter half of 2014 and continued throughout 2015 and the first half of 2016. The impairment recorded in the third quarter of 2016 resulted primarily from downward revisions to forecasted reserves due to a decrease in projected Mid-Continent production volumes.

(3) Impairment in 2014 resulted from the divestiture of the Gulf Properties.

(4) Impairment recorded in the Predecessor 2016 Period and the year ended December 31, 2015, resulted from discontinued drilling operations in its Permian region which resulted in an impairment on certain drilling assets after determining their future use was limited. During 2014, the Company recorded a $24.3 million impairment on its drilling and oilfield services assets in the Permian region as a result of fulfilling its drilling obligation with the Permian Trust in 2014 and the downward trend in oil prices that began in the second half of 2014.

(5) Impairment in the Predecessor 2016 Period resulted from a decrease in projected Mid-Continent production volumes supporting the system’s usage.

(6) Impairment in the Predecessor 2016 Period and the years ended December 31, 2015 and 2014 resulted from the evaluation of certain midstream pipe inventory, natural gas compressors, gas treating plants and a carbon dioxide (“CO_2”) compressor station after determining that their future use was limited.

(7) Impairment recorded on other assets in 2015, includes a $15.4 million impairment on property located in downtown Oklahoma City, Oklahoma to adjust the carrying value of the property to the agreed upon sales price for which it was later sold in 2016.

10. Accounts Payable and Accrued Expenses

Accounts payable and accrued expenses consist of the following (in thousands):

	Successor December 31, 2016	Predecessor December 31, 2015
Accounts payable and other accrued expenses	$ 65,408	$ 231,697
Accrued interest	648	73,320
Production payable	16,011	55,260
Payroll and benefits	33,606	42,728
Convertible perpetual preferred stock dividends	—	21,572
Drilling advances	844	2,295
Related party	—	1,545
Total accounts payable and accrued expenses	$ 116,517	$ 428,417

11. Long-Term Debt

Long-term debt consists of the following (in thousands):

	Successor December 31, 2016	Predecessor December 31, 2015
New First Lien Exit Facility	$ —	$ —
New Convertible Notes	268,780	—
New Building Note	36,528	—
Senior credit facility	—	—
8.75% Senior Secured Notes due 2020	—	1,265,814
Senior Unsecured Notes		
8.75% Senior Notes due 2020	—	389,232
7.5% Senior Notes due 2021	—	751,087
8.125% Senior Notes due 2022	—	518,693
7.5% Senior Notes due 2023	—	534,869
Convertible Senior Unsecured Notes		
8.125% Convertible Senior Notes due 2022	—	78,290
7.5% Convertible Senior Notes due 2023	—	24,393
Total debt	305,308	3,562,378
Less: current maturities of long-term debt	—	—
Long-term debt	$ 305,308	$ 3,562,378

On the Emergence Date, the balance outstanding under the senior credit facility of $449.2 million, par value of the Senior Secured Notes of $1.3 billion, par value of the Senior Unsecured Notes of $2.2 billion and par value of the Convertible Senior Unsecured Notes of $87.6 million were canceled upon emergence from bankruptcy and the Company entered into the New First Lien Exit Facility, issued New Convertible Notes and entered into the New Building Note as discussed further below. See Note 1 for additional information regarding the bankruptcy proceedings.

See Note 6 for the fair values and carrying values of the long-term debt outstanding at December 31, 2016 and 2015, respectively, and Note 2 for fresh start values calculated as of the Emergence Date. As of December 31, 2015, there were no amounts outstanding under the senior credit facility, and the carrying values of the senior notes were net of unamortized discounts, premiums and deferred costs of $342.6 million, and included the fair value of debt derivatives of $32.3 million. A non-cash charge to write off all of the related unamortized debt issuance costs and associated discounts and premiums of approximately $158.6 million and the fair value of associated debt derivatives of $9.8 million as of May 16, 2016, is included in reorganization items in the accompanying consolidated statement of operations for the Predecessor 2016 Period, as discussed in Note 1 and Note 2.

Successor Company Indebtedness

New First Lien Exit Facility. As discussed in Note 1, on the Emergence Date, the Company entered into the New First Lien Exit Facility with the lenders party thereto and Royal Bank of Canada, as administrative agent and issuing lender.

The initial borrowing base under the New First Lien Exit Facility is $425.0 million. There are no scheduled borrowing base redeterminations until October 2018, followed by scheduled semiannual borrowing base redeterminations thereafter. The New First Lien Exit Facility matures on February 4, 2020. The outstanding borrowings under the New First Lien Exit Facility bear interest at a rate equal to, at the option of the Company, either (a) a base rate plus an applicable rate of 3.75% per annum or (b) LIBOR plus 4.75% per annum, subject to a 1.00% LIBOR floor. Interest on base rate borrowings is payable quarterly in arrears and interest on LIBOR borrowings is payable every one, two, three or six months, at the election of the Company. Quarterly, the Company pays commitment fees assessed at annual rates of 0.50% on any available portion of the New First Lien Exit Facility. The Company has the right to prepay loans under the New First Lien Exit Facility at any time without a prepayment penalty, other than customary “breakage” costs with respect to LIBOR loans.

Furthermore, the New First Lien Exit Facility is secured by (i) first-priority mortgages on at least 95% of the PV-9 valuation of the proved developed producing reserves and 95% of the PV-9 valuation of all proved reserves included in the most recently delivered reserve report of the Company, (ii) a first-priority perfected pledge of capital stock of each credit party and their respective wholly owned subsidiaries and (iii) a first-priority security interest in the cash, cash equivalents, deposit, securities and other similar accounts, and a first-priority perfected security interest in substantially all other tangible and intangible assets of the credit parties (including but not limited to as-extracted collateral, accounts receivable, inventory, equipment, general intangibles, investment property, intellectual property, real property and the proceeds of the foregoing).

The New First Lien Exit Facility requires the Company to, (a) commencing with the first full fiscal quarter ending after the Protected Period, maintain a minimum proved developing producing reserves asset coverage ratio, measured as of the last day of each fiscal quarter, of 1.75 to 1.00 and (b) commencing with the first full fiscal quarter ending after the occurrence of the end of the Protected Period, maintain (i) a maximum consolidated total net leverage ratio, measured as of the last day of each fiscal quarter, (A) on or prior to December 31, 2018, of no greater than 3.50 to 1.00, and (B) any fiscal quarter ending on or after March 31, 2019, of no greater than 3.00 to 1.00 and (ii) a minimum consolidated interest coverage ratio, measured as of the last day of each fiscal quarter, of no less than 2.00 to 1.00. Such financial covenants are subject to customary cure rights.

The New First Lien Exit Facility contains customary affirmative and negative covenants, including compliance with laws (including environmental laws, ERISA and anti-corruption laws), maintenance of required insurance, delivery of quarterly and annual financial statements, oil and gas engineering reports, maintenance and operation of property (including oil and gas properties), restrictions on the incurrence of liens, indebtedness, asset dispositions, fundamental changes, restricted payments and other customary covenants.

The Company had no amounts outstanding under the New First Lien Exit Facility at December 31, 2016 and $8.6 million in outstanding letters of credit, which reduce availability under the New First Lien Exit Facility on a dollar-for-dollar basis.

The Company subsequently refinanced the New First Lien Exit Facility in February 2017. See Note 21 for additional discussion.

New Convertible Notes. As discussed in Note 1, on the Emergence Date, pursuant to the terms of the Plan, the Company issued approximately $281.8 million principal amount of New Convertible Notes, which do not bear regular interest and will mature and mandatorily convert into New Common Stock on October 4, 2020, unless repurchased, redeemed or converted prior to that date. The New Convertible Notes were recorded at fair value of $445.7 million upon implementation of fresh start accounting. As the associated premium of $163.9 million was deemed significant to the principal amount of the New Convertible Notes, it was recorded in additional paid in capital in the consolidated balance sheet at December 31, 2016. Upon the occurrence of certain events, including any acceleration, repayment or prepayment of the New Convertible Notes (including any optional redemption), the Company will be required to pay a make-whole amount of $0.783478 for each $1.00 in principal amount of New Convertible Notes repaid or prepaid in accordance with the provisions of the associated indenture.

The New Convertible Notes are initially convertible at a conversion rate of 0.05330841 shares of New Common Stock per $1.00 principal amount of New Convertible Notes, which represents, in the aggregate, approximately 15.0 million shares of the New Common Stock. The conversion rate for the New Convertible Notes is subject to customary anti-dilution adjustments. In addition, upon the occurrence of certain events, including any acceleration, repayment or prepayment of the New Convertible Notes (including any optional redemption), the conversion rate will be automatically adjusted such that the New Convertible Notes convert into the same percentage of New Common Stock before and after such event.

The New Convertible Notes are convertible at the option of the holders at any time up to, and including, the business day immediately preceding the maturity date. In addition, the Company is required to convert all outstanding New Convertible Notes upon the earliest to occur of the following: (i) any bona fide arm’s length issuance by the Company of New Common Stock to third parties for cash with (a) a total issuance size that is greater than or equal to $100.0 million and (b) a per-share price greater than or equal to $34.16; (ii) 30 days’ written notice to the Company to convert the New Convertible Notes from holders of at least a majority in aggregate principal amount of the New Convertible Notes then outstanding; (iii) the average of the last reported sale prices of the New Common Stock over a 30 consecutive trading day period is 50% greater than $34.16; (iv) any bona fide refinancing of the New First Lien Exit Facility after a determination by the post-emergence board of directors in good faith that: (a) such refinancing provides for terms that are materially more favorable to the Company and (b) the causing of a conversion is not the primary purpose of such refinancing; (v) any change of control transaction; or (vi) the maturity date. Upon conversion, the Company will deliver shares of New Common Stock equal to the conversion rate, together with a cash payment in lieu of delivering any fractional share of New Common Stock issuable upon conversion, based on the last reported sale price of the New Common Stock on the relevant conversion date. During the Successor 2016 Period, holders of approximately $13.0 million in aggregate principal amount of the New Convertible Notes exercised conversion options applicable to those notes, resulting in the issuance of approximately 0.7 million shares of New Common Stock.

The Company may redeem for cash all or part of the New Convertible Notes at any time prior to the maturity date, at a redemption price equal to 100% of the principal amount of such New Convertible Notes to be redeemed, as increased by the make-whole amount. With respect to any New Convertible Notes selected for redemption that are converted following a redemption notice, the conversion rate will be automatically adjusted such that the New Convertible Notes convert into the same percentage of New Common Stock before and after such redemption notice.

The Company’s obligations pursuant to the New Convertible Notes are fully and unconditionally guaranteed, jointly and severally, by each of the Guarantors of the New First Lien Exit Facility. Following the occurrence of certain events, the Company would be required to secure $100.0 million of the New Convertible Notes, which amount may be increased to the full outstanding principal amount of the New Convertible Notes, including any applicable make-whole amount, in accordance with the provisions of the New Convertible Notes Indenture (the “Springing Lien”). The Springing Lien will be a second priority lien on the same collateral securing the New First Lien Exit Facility.

The remaining outstanding New Convertible Notes were converted into shares of New Common Stock as a result of the Company’s entry into the refinanced credit facility on February 10, 2017, as discussed in Note 21.

New Building Note. As discussed in Note 1, on the Emergence Date, the Company entered into the New Building Note, which has a principal amount of $35.0 million and is secured by first priority mortgage on the Company’s headquarters facility and certain other non-oil and gas real property. The New Building Note was recorded at fair value of $36.6 million upon implementation of fresh start accounting. Interest is payable on the New Building Note at 6% per annum for the first year following the Emergence Date, 8% per annum for the second year following the Emergence Date, and 10% thereafter through maturity. The effective interest rate was 10.9% for the New Building Note at December 31, 2016. Interest is payable in kind from the Emergence Date through the earlier of September 30, 2020, 46 months from the Emergence Date or 90 days after the refinancing or repayment of the New First Lien Exit Facility and thereafter in cash. The New Building Note matures on October 4, 2021. On the Emergence Date, pursuant to the Plan, certain holders of the Unsecured Senior Notes purchased the New Building Note for $26.8 million in cash, net of certain fees and expenses.

Predecessor Company Indebtedness

Senior Credit Facility. The terms of the senior credit facility contained certain financial covenants, including maintenance of agreed upon levels for the (a) ratio of total secured debt under the senior credit facility to earnings before interest, taxes, depreciation and amortization ("EBITDA"), which could not exceed 2.00:1.00 at each quarter end and (b) ratio of current assets to current liabilities, which was required to be at least 1.0:1.0 at each quarter end. For the purpose of the current ratio calculation, any amounts available to be drawn under the senior credit facility were included in current assets and unrealized assets and liabilities that resulted from mark-to-market adjustments on the Company's commodity derivative contracts were disregarded. The senior credit facility matured by its terms on the earlier of March 2, 2020 and 91 days prior to the earliest date of any maturity under or mandatory offer to repurchase the Company's then outstanding notes.

The senior credit facility also contained various covenants that limited the ability of the Company and certain of its subsidiaries to: grant certain liens; make certain loans and investments; make distributions; redeem stock; redeem or prepay debt; merge or consolidate with or into a third party; or engage in certain asset dispositions, including a sale of all or substantially all of the Company's assets. The terms of the senior credit facility allowed the Company to redeem or purchase outstanding Senior

Unsecured Notes for up to $275.0 million in cash subject to certain limitations. Additionally, the senior credit facility limited the ability of the Company and certain of its subsidiaries to incur additional indebtedness with certain exceptions.

The obligations under the senior credit facility were guaranteed by certain Company subsidiaries and were required to be secured by first priority liens on all shares of capital stock of certain of the Company's material present and future subsidiaries, all of the Company's intercompany debt, and certain of the Company's other assets, including proved oil, natural gas and NGL reserves representing at least 80.0% of the discounted present value (as defined in the senior credit facility) of proved oil, natural gas and NGL reserves of the Company.

At the Company's election, interest under the senior credit facility, was determined by reference to (a) LIBOR plus an applicable margin between 1.750% and 2.750% per annum or (b) the "base rate," which is the highest of (i) the federal funds rate plus 0.5%, (ii) the prime rate published by Royal Bank of Canada under the senior credit facility or (iii) the one-month Eurodollar rate (as defined in the senior credit facility) plus 1.00% per annum, plus, in each case under scenario (b), an applicable margin between 0.750% and 1.750% per annum. Interest was payable quarterly for base rate loans and at the applicable maturity date for LIBOR loans, except that if the interest period for a LIBOR loan was six months or longer, interest was paid at the end of each three-month period. Quarterly, the Company paid commitment fees assessed at annual rates of 0.5% on any available portion of the senior credit facility.

On March 11, 2016, the administrative agent notified the Company that the lenders had elected to reduce the borrowing base to $340.0 million from $500.0 million pursuant to a special redetermination. On April 20, 2016, the Company submitted for consideration by its lenders additional properties to serve as collateral under the senior credit facility to support a borrowing base of $500.0 million. On May 11, 2016, in exchange for waivers from the requisite percentage of lenders with respect to certain specified defaults and events of defaults under the senior credit facility, the Company permanently repaid $40.0 million of borrowings to the lenders, which payment correspondingly reduced the lenders' commitments.

Senior Secured Notes. The Company issued $1.25 billion of 8.75% Senior Secured Notes due 2020 in June 2015. Net proceeds from the issuance were approximately $1.21 billion after deducting offering expenses, a portion of which was used to repay amounts outstanding at that time under the Company's senior credit facility.

Additionally, the Company issued $78.0 million par value of the PGC Senior Secured Notes in conjunction with the acquisition of and termination of a gathering agreement with PGC in October 2015. Because the PGC Senior Secured Notes were issued as partial consideration for the acquisition and termination, these notes were recorded at fair value of approximately $50.3 million, which included mandatory prepayment feature liabilities and a discount. Fair value at issuance was determined based upon the then-current market value of the Senior Secured Notes. The unamortized portions of the discount and the carrying value of the mandatory prepayment feature as of the date of the Chapter 11 filings, May 16, 2016, were written off to reorganization items on the accompanying consolidated statement of operations for the Predecessor 2016 Period as discussed in Note 1.

The Company accrued interest on its Senior Secured Notes at a fixed rate of 8.75% prior to the Chapter 11 filings, with no interest accrued subsequent to the filings. The Senior Secured Notes were by their terms redeemable, in whole or in part, prior to their maturity at specified redemption prices and were jointly and severally guaranteed unconditionally, in full, on a second-priority secured basis by certain of the Company's wholly owned subsidiaries.

The Senior Secured Notes were secured by second-priority liens on all of the Company's assets that secured the senior credit facility on a first-priority basis; provided, however, the security interest in those assets that secured the Senior Secured Notes and the guarantees were contractually subordinated to liens thereon that secured the credit facility and certain other permitted indebtedness. Consequently, the Senior Secured Notes and the guarantees were effectively subordinated to the credit facility and such other indebtedness to the extent of the value of such assets.

Pursuant to the indenture, the Senior Secured Notes by their terms matured on June 1, 2020; provided, however, that if on October 15, 2019, the aggregate outstanding principal amount of the unsecured 8.75% Senior Notes due 2020 exceeded $100.0 million, the Senior Secured Notes would mature on October 16, 2019. See further discussion of the mandatory prepayment feature at Note 6 and Note 12, which with respect to the PGC Senior Secured Notes was an embedded derivative that was accounted for separately from these notes, and was written off to reorganization items on the accompanying consolidated statement of operations for the Predecessor 2016 Period as discussed in Note 1.

The indenture governing the Senior Secured Notes contained covenants that restricted the Company's ability to pay dividends, incur indebtedness, create liens, enter into consolidations or mergers, purchase or redeem stock or subordinated or unsecured indebtedness, dispose of or transfer certain assets, transact with related parties, make investments and refinance certain indebtedness, among other actions. These indentures were canceled upon the Company's emergence from Chapter 11. See

Note 1 for additional details about the Company's Bankruptcy Petitions and the Chapter 11 proceedings.

Senior Unsecured Notes. The Company accrued interest on its Senior Unsecured Notes at a fixed rate through the date of the Chapter 11 filings, with no interest accrued subsequent to the filings. Certain of the Senior Unsecured Notes were issued at a discount or a premium. Prior to the Chapter 11 filings, the discount or premium was amortized to interest expense over the term of the respective series of Senior Unsecured Notes. The unamortized portions of the discount or premium as of the date of the Chapter 11 filings, May 16, 2016, were written off to reorganization items on the accompanying consolidated statement of operations for the Predecessor 2016 Period as discussed in Note 1.

Each of the indentures governing the Company's Senior Unsecured Notes contained covenants that restricted the Company's ability to pay dividends, incur indebtedness, make investments, sell certain assets, purchase certain assets, transact with related parties and enter into consolidations or mergers. These indentures were canceled upon the Company's emergence from Chapter 11.

Convertible Senior Unsecured Notes. The Convertible Senior Unsecured Notes were issued in conjunction with exchanges and repurchases of Senior Unsecured Notes that took place in August and October 2015. The transactions were determined to be an extinguishment of each of the Senior Unsecured Notes exchanged. As such, the newly-issued Convertible Senior Unsecured Notes were recorded at fair value on the date of issuance. The Convertible Senior Unsecured Notes were guaranteed by the same Guarantors that guaranteed the Senior Unsecured Notes and were subject to covenants and bore payment terms substantially identical to those of the corresponding series of Senior Unsecured Notes of similar tenor, other than the conversion features, described further below, and the extension of the final maturity by one day. The Company accrued interest on its Convertible Senior Unsecured Notes at a fixed rate through the date of the Chapter 11 filings, with no interest accrued subsequent to the filings.

During the Predecessor 2016 Period, holders of $200.5 million aggregate principal amount ($67.4 million net of discount and including holders' conversion feature) of 8.125% Convertible Senior Notes due 2022 and $31.6 million aggregate principal amount ($10.4 million net of discount and holders' conversion feature) of 7.5% Convertible Senior Notes due 2023 exercised conversion options applicable to those notes, resulting in the issuance of approximately 84.4 million shares of Company common stock and aggregate cash payments of $33.5 million for accrued interest and early conversion payments. The conversions resulted in a gain on extinguishment of debt totaling $41.3 million, including the write off of $4.3 million of net unamortized debt issuance costs, which is included in other income on the accompanying consolidated statement of operations for the Predecessor 2016 Period.

During the year ended December 31, 2015, holders of $186.6 million aggregate principal amount ($54.4 million net of discount and including holders' conversion feature) of 8.125% Convertible Senior Notes due 2022 and $68.7 million aggregate principal amount ($19.3 million net of discount and holders' conversion feature) of 7.5% Convertible Senior Notes due 2023 exercised conversion options applicable to those notes, resulting in the issuance of approximately 92.8 million shares of Company common stock and aggregate cash payments of $30.5 million for accrued interest and early conversion payments. The conversions resulted in a gain on extinguishment of debt totaling $6.1 million, including the write off of $5.2 million of net unamortized debt issuance costs, which is included in other income on the accompanying consolidated statement of operations for year ended December 31, 2015.

Maturities of Long-Term Debt

As of December 31, 2016, $268.8 million of long-term debt will contractually mature in 2020 and $35.0 million, plus any unpaid interest on the New Building Note, will mature in 2021.

12. Derivatives

The Company has not designated any of its derivative contracts as hedges for accounting purposes. The Company records all derivative contracts at fair value. Changes in derivative contract fair values are recognized in earnings.

Commodity Derivatives

The Company is exposed to commodity price risk, which impacts the predictability of its cash flows from the sale of oil and natural gas. The Company seeks to manage this risk through the use of commodity derivative contracts, which allow the Company to limit its exposure to commodity price volatility on a portion of its forecasted oil and natural gas sales. None of the Company’s commodity derivative contracts may be terminated prior to contractual maturity solely as a result of a downgrade in the credit rating of a party to the contract. Cash settlements and valuation gains and losses on commodity derivative contracts are included in loss (gain) on derivative contracts in the consolidated statements of operations. Commodity derivative contracts are settled on a monthly or quarterly basis. Derivative assets and liabilities arising from the Company's commodity derivative contracts with the same counterparty that provide for net settlement are reported on a net basis in the consolidated balance sheets. At December 31, 2016, the Company's commodity derivative contracts consisted of fixed price swaps under which the Company receives a fixed price for the contract and pays a floating market price to the counterparty over a specified period for a contracted volume.

The Company recorded loss on commodity derivative contracts of $25.7 million and $4.8 million for the Successor 2016 Period and the Predecessor 2016 Period, respectively, as reflected in the accompanying consolidated statements of operations, which includes net cash receipts upon settlement of $7.7 million and $72.6 million, respectively. The net receipts for the Predecessor 2016 Period include settlements of contracts prior to their contractual maturity ("early settlements") after the Chapter 11 filings occurred, resulting in $17.9 million of cash receipts.

The Company recorded gain on commodity derivative contracts of $73.1 million and $334.0 million for the years ended December 31, 2015 and 2014, respectively, as reflected in the accompanying consolidated statements of operations, which includes net cash (receipts) payments upon settlement of $(327.7) million and $32.3 million, respectively. Included in the net cash payments for 2014 are $69.9 million of cash payments related to early settlements primarily as a result of the sale of the Gulf Properties in February 2014.

Derivatives Agreements with Royalty Trusts. During the years ended December 31, 2015 and 2014, the Company was party to derivatives agreements with the Mississippian Trust I, Permian Trust and Mississippian Trust II to provide each Royalty Trust with the economic effect of certain oil and natural gas derivative contracts entered into by the Company with third parties. The derivatives agreements with the Mississippian Trust I and the Mississippian Trust II contained commodity derivative contracts that covered volumes of oil and natural gas production through December 31, 2015, and the derivatives agreement with the Permian Trust contained commodity derivative contracts that covered volumes of oil production through March 31, 2015. All activity related to the contracts underlying the derivatives agreements with the Royalty Trusts have been included in the Company's consolidated derivative disclosures.

Master Netting Agreements and the Right of Offset. The Company has master netting agreements with all of its commodity derivative counterparties and has presented its derivative assets and liabilities with the same counterparty on a net basis by commodity type in the consolidated balance sheets. As a result of the netting provisions, the Company's maximum amount of loss under commodity derivative transactions due to credit risk is limited to the net amounts due from its counterparties. As of December 31, 2016, the counterparties to the Company's open commodity derivative contracts consisted of four financial institutions, all of which are also lenders under the Company's New First Lien Exit Facility. The Company is not required to post additional collateral under its commodity derivative contracts as certain of the counterparties to the Company's commodity derivative contracts share in the collateral supporting the Company's New First Lien Exit Facility. The following tables summarize (i) the Company's commodity derivative contracts on a gross basis, (ii) the effects of netting assets and liabilities for which the right of offset exists based on master netting arrangements and (iii) for the Company's net derivative liability positions, the applicable portion of shared collateral under the New First Lien Exit Facility and senior credit facility (in thousands):

December 31, 2016 - Successor

	Gross Amounts	Gross Amounts Offset	Amounts Net of Offset	Financial Collateral	Net Amount
Assets					
Derivative contracts - current	$ —	$ —	$ —	$ —	$ —
Derivative contracts - noncurrent	—	—	—	—	—

Total	$ —	$ —	$ —	$ —	$ —
Liabilities					
Derivative contracts - current	$ 27,538	$ —	$ 27,538	$ (27,538)	$ —
Derivative contracts - noncurrent	2,176	—	2,176	(2,176)	—
Total	$ 29,714	$ —	$ 29,714	$ (29,714)	$ —

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

December 31, 2015 - Predecessor

	Gross Amounts	Gross Amounts Offset	Amounts Net of Offset	Financial Collateral	Net Amount
Assets					
Derivative contracts - current	$ 85,524	$ (1,175)	$ 84,349	$ —	$ 84,349
Derivative contracts - noncurrent	—	—	—	—	—
Total	$ 85,524	$ (1,175)	$ 84,349	$ —	$ 84,349
Liabilities					
Derivative contracts - current	$ 1,748	$ (1,175)	$ 573	$ (573)	$ —
Derivative contracts - noncurrent	—	—	—	—	—
Total	$ 1,748	$ (1,175)	$ 573	$ (573)	$ —

At December 31, 2016, the Company's open commodity derivative contracts consisted of the following:

Oil Price Swaps

	Notional (MBbls)	Weighted Average Fixed Price
January 2017 - December 2017	3,285	$ 52.24
January 2018 - December 2018	1,825	$ 55.34

Natural Gas Price Swaps

	Notional (MMcf)	Weighted Average Fixed Price
January 2017 - December 2017	32,850	$ 3.20
January 2018 - December 2018	3,650	$ 3.12

Predecessor Debt - Embedded Derivatives

Debt Holder Conversion Feature. As discussed further in Note 6 and Note 11, the Convertible Senior Unsecured Notes contained a conversion feature that was exercisable at the holders' option. This conversion feature was identified as an embedded derivative as the feature (i) possessed economic characteristics that were not clearly and closely related to the economic characteristics of the host contract, the Convertible Senior Unsecured Notes, and (ii) separate, stand-alone instruments with the same terms would have qualified as derivative instruments. As such, the holders' conversion feature was bifurcated and accounted for separately from the Convertible Senior Unsecured Notes. The holders' conversion feature was recorded at fair value each reporting period with changes in fair value included in interest expense in the accompanying consolidated statement of operations for the Predecessor 2016 Period and the year ended December 31, 2015. Subsequent to the Chapter 11 filings, the value of the debt holder conversion features was written off and is included in reorganization items in the accompanying consolidated statement of operations for the Predecessor 2016 Period.

Mandatory Prepayment Feature - PGC Senior Secured Notes. As discussed further in Note 6 and Note 11, the Senior Secured Notes contained a mandatory prepayment feature that was triggered if the outstanding principal amount of the unsecured 8.75% Senior Notes due 2020 exceeded $100.0 million on October 15, 2019. With respect to the PGC Senior Secured Notes, which were issued at a substantial discount, this mandatory prepayment feature was identified as an embedded derivative as the feature (i) possessed economic characteristics that were not clearly and closely related to the economic characteristics of the host contract, the PGC Senior Secured Notes, and (ii) separate, stand-alone instruments with the same terms would have qualified as derivative instruments. As such, the mandatory prepayment feature contained in the PGC Senior Secured Notes was bifurcated and accounted for separately from those notes. The mandatory prepayment feature contained in the PGC Senior Secured notes was recorded at fair value each reporting period with changes in fair value included in interest expense in the accompanying consolidated statements of operations for the Predecessor 2016 Period and the year ended December 31, 2015. Subsequent to the Chapter 11 filings, the value of the mandatory prepayment feature was written off and is included in reorganization items in the accompanying consolidated statement of operations for the Predecessor 2016 Period.

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

Fair Value of Derivatives

The following table presents the fair value of the Company’s derivative contracts on a gross basis without regard to same-counterparty netting (in thousands):

Type of Contract	Balance Sheet Classification	Successor December 31, 2016	Predecessor December 31, 2015
Derivative assets			
Oil price swaps	Derivative contracts - current	$—	$ 68,224
Oil collars—three way	Derivative contracts - current	—	17,300
Derivative liabilities			
Oil price swaps	Derivative contracts - current	(13,395)	—
Natural gas price swaps	Derivative contracts - current	(14,143)	—
Natural gas basis swaps	Derivative contracts - current	—	(1,748)
Debt holder conversion feature	Current maturities of long-term debt	—	(29,355)
Mandatory prepayment feature - PGC Senior Secured Notes	Current maturities of long-term debt	—	(2,941)
Oil price swaps	Derivative contracts - noncurrent	(2,105)	—
Natural gas price swaps	Derivative contracts - noncurrent	(71)	—
Total net derivative contracts		$(29,714)	$ 51,480

See Note 6 for additional discussion of the fair value measurement of the Company’s derivative contracts and Note 11 for discussion of the debt holder conversion and mandatory prepayment features.

13. Asset Retirement Obligations

The following table presents the balance and activity of the asset retirement obligations (in thousands):

	Successor Period from October 2, 2016 through December 31, 2016	Predecessor Period from January 1, 2016 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Beginning balance	$ 92,413	$ 103,578	$ 54,402	$ 424,117
Liability incurred upon acquiring and drilling wells	121	505	1,662	4,968
Revisions in estimated cash flows(1)	12,397	—	44,060	(5,848)
Liability settled or disposed in current period(2)	(540)	(36,979)	(1,023)	(377,927)
Accretion	2,090	4,365	4,477	9,092
Impact of fresh start accounting	—	20,944	—	—
Ending balance	106,481	92,413	103,578	54,402
Less: current portion	66,154	65,678	8,399	—
Asset retirement obligations, net of current	$ 40,327	$ 26,735	$ 95,179	$ 54,402

(1)

Revisions for the Successor 2016 Period and the year ended December 31, 2015 relate primarily to changes in estimated well lives.

(2) Liability settled or disposed for the Predecessor 2016 Period includes $34.1 million associated with the WTO Properties sold in January 2016. Liability settled or disposed for the year ended December 31, 2014, includes $366.0 million associated with the Gulf Properties sold in February 2014. For further discussion of the sale of properties see Note 5.

F-42

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

14. Commitments and Contingencies

Employee Termination Benefits. Certain employees received termination benefits, including severance and accelerated stock vesting, upon separation of service from the Company during the years ended December 31, 2016, 2015 and 2014. Employee termination benefits were $12.3 million for the Successor 2016 Period, with approximately $5.7 million accrued at December 31, 2016 for payment in the first quarter of 2017 and $18.4 million for the Predecessor 2016 Period, primarily as a result of reductions in workforce. For the years ended December 31, 2015 and 2014, employee termination benefits were $12.5 million and $8.9 million, respectively, primarily as a result of a reduction in workforce and executives' separation from employment, and the sale of the Gulf Properties.

Risks and Uncertainties. The Company's revenue, profitability and future growth are substantially dependent upon the prevailing and future prices for oil and natural gas, which depend on numerous factors beyond the Company's control such as overall oil and natural gas production and inventories in relevant markets, economic conditions, the global political environment, regulatory developments and competition from other energy sources. Oil and natural gas prices historically have been volatile, and may be subject to significant fluctuations in the future. The Company enters into commodity derivative arrangements in order to mitigate a portion of the effect of this price volatility on the Company's cash flows. See Note 12 for the Company's open oil and natural gas commodity derivative contracts.

The Company historically has depended on cash flows from operating activities and, as necessary, borrowings under its senior credit facility to fund its capital expenditures. Based on its cash balances, cash flows from operating activities and net borrowing availability under the New First Lien Exit Facility, the Company expects to be able to fund its planned capital expenditures budget, debt service requirements and working capital needs for 2017; however, oil or natural gas prices decline from current levels, they would have a material adverse effect on the Company's financial position, results of operations, cash flows and quantities of oil, natural gas and NGL reserves that may be economically produced. The Company subsequently refinanced the New First Lien Exit Facility in February 2017. See Note 21 for additional discussion.

Litigation and Claims

Chapter 11 Proceedings

The Plan in the Chapter 11 Cases discharged claims, including claims related to litigation proceedings against the Company that arose before such 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 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.

Successor Claims

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.

Predecessor Claims

As previously disclosed, on February 4, 2015, the staff of the Securities and Exchange Commission (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 as a result of 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 CO2 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.

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.

15. Equity

Successor Equity

New Common Stock. As discussed in Note 1, on the Emergence Date, the Company issued an aggregate of approximately 18.9 million shares of its New Common Stock, par value $0.001 per share, to the holders of allowed claims, as defined in the Plan, and approximately 0.4 million shares of New Common Stock were reserved for future distributions under the Plan. Additionally, during the Successor 2016 Period, voluntary conversions of New Convertible Notes resulted in the issuance of New Company Stock. See Note 11 for further discussion of the New Convertible Notes.

Warrants. As discussed in Note 1, on the Emergence Date, the Company issued approximately 4.9 million Series A Warrants, 4.5 million of which was issued immediately upon emergence and 2.1 million Series B Warrants, 1.9 million of which was issued immediately upon emergence, that were initially exercisable for one share of New Common Stock per Warrant at initial exercise prices of $41.34 and $42.03 per share, respectively, subject to adjustments pursuant to the terms of the Warrants, to certain holders of general unsecured claims as defined in the Plan. The Warrants are exercisable from the Emergence Date until October 4, 2022. The Warrants contain customary anti-dilution adjustments in the event of any stock split, reverse stock split, reclassification, stock dividend or other distributions.

Unregistered Sales of Equity Securities. The Company relied on Section 1145(a)(1) of the Bankruptcy Code as an exemption from the registration requirements of the Securities Act for the issuance of the New Common Stock, the New Convertible Notes and the Warrants. Section 1145(a)(1) of the Bankruptcy Code exempts the offer and sale of securities under a plan of reorganization from registration under Section 5 of the Securities Act and state laws if three principal requirements are satisfied:

- the securities must be issued under a plan of reorganization by the debtor, its successor under a plan, or an affiliate participating in a joint plan of reorganization with the debtor;
- the recipients of the securities must hold a claim against, an interest in, or a claim for administrative expense in the case concerning the debtor or such affiliate; and
- the securities must be issued either (a) in exchange for the recipient's claim against, interest in or claim for administrative expense in the case concerning the debtor or such affiliate or (b) principally in such exchange and partly for cash or property.

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

Treasury Stock. The Company makes required statutory tax payments on behalf of employees when their restricted stock awards vest and withhold a number of vested shares of common stock having a value on the date of vesting equal to the tax obligation. The number of shares withheld for taxes and the associated value of those shares for the Successor 2016 Period were insignificant. These shares were accounted for as treasury stock when withheld, and then immediately retired.

Predecessor Equity

Preferred Stock. As discussed in Note 1, on the Emergence Date the Company's authorized 7.0% and 8.5% convertible perpetual preferred stock was canceled and released under the Plan without receiving any recovery on account thereof.

Each outstanding share of convertible perpetual preferred stock was convertible at the holder's option at any time into shares of the Company's common stock at the specified conversion rate, subject to customary adjustments in certain circumstances. Each holder was entitled to an annual dividend payable semi-annually in cash, common stock or a combination thereof, at the Company's election. The Company could cause all outstanding shares of the convertible perpetual preferred stock to convert automatically into common stock at the prevailing conversion rate dependent on certain factors, including the Company's stock trading above specified prices for a set period. The convertible perpetual preferred stock was not redeemable by the Company at any time. For the year ended December 31, 2015, approximately 0.2 million shares were converted into approximately 3.0 million shares of the Predecessor Company's common stock. The following table summarizes information about each series of the Predecessor Company's convertible perpetual preferred stock outstanding at December 31, 2015:

	Convertible Perpetual Preferred Stock	
	8.5%	7.0%
Liquidation preference per share	$100.00	$100.00
Annual dividend per share	$8.50	$7.00
Conversion rate per share to common stock	12.4805	12.8791

Preferred Stock Dividends. Prior to the Chapter 11 petition filings, dividends on the Company's 8.5% and 7.0% convertible perpetual preferred stock could be paid in cash or with shares of the Company's common stock at the Company's election.

In the first quarter of 2016, prior to the February semi-annual dividend payment date, the Company announced the suspension of the semi-annual dividend on its 8.5% convertible perpetual preferred stock. The Company suspended payment of the cumulative dividend on its 7.0% convertible perpetual preferred stock during the third quarter of 2015. The final dividend payment for the previously outstanding 6.0% convertible preferred stock was made during 2014, as it fully converted to common stock in 2014. The Company ceased accruing dividends on its 8.5% and 7.0% convertible perpetual preferred stock as of May 16, 2016, in conjunction with the Chapter 11 petition filings.

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

Preferred stock dividend payments and accruals for the Company's 8.5%, 7.0% and 6.0% convertible perpetual preferred stock are as follows (in thousands):

	Predecessor Period from January 1, 2016 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
8.5% Convertible perpetual preferred stock			
Dividends paid in cash	$—	$ 11,262	$ 22,525
Dividends satisfied in shares of common stock(1)	$—	$ 11,262	$ —
Accrued dividends at period end	$—	$ 8,447	$ 8,447
Dividends in arrears	$11,262	$ —	$ —
7.0% Convertible perpetual preferred stock			
Dividends paid in cash	$—	$ —	$ 21,000
Dividends satisfied in shares of common stock(2)	$—	$ 10,500	$ —
Accrued dividends at period end	$—	$ 13,125	$ 2,625
Dividends in arrears	$21,000	$ 10,500	$ —
6.0% Convertible perpetual preferred stock			
Dividends paid in cash	$—	$ —	$ 12,000
Accrued dividends at period end	$—	$ —	$ —

(1) For the year ended December 31, 2015, the Company paid a semi-annual dividend by issuing approximately 18.6 million shares of common stock. For purposes of the dividend payment, the value of each share issued was calculated as 95% of the average volume-weighted share price for the 15 trading day period ending July 29, 2015. Based upon the common stock's closing price on August 17, 2015, the common stock issued had a market value of approximately $9.5 million, ($3.58 per outstanding share at the time the dividend was paid) that resulted in a difference between the fixed rate semi-annual dividend and the value of shares issued of approximately $1.8 million, which was recorded as a reduction to preferred stock dividends in the accompanying consolidated statement of operations.

(2) For the year ended December 31, 2015, the Company paid a semi-annual dividend by issuing approximately 5.7 million shares of common stock. For purposes of the dividend payment, the value of each share issued was calculated as 95% of the average volume-weighted share price for the 15 trading day period ending April 28, 2015. Based upon the common stock's closing price on May 15, 2015, the common stock issued had a market value of approximately $6.7 million, ($2.23 per outstanding share at the time the dividend was paid) that resulted in a difference between the fixed rate semi-annual dividend and the value of shares issued of approximately $3.8 million, which was recorded as a reduction to preferred stock dividends in the accompanying consolidated statement of operations.

Paid and unpaid dividends included in the calculation of (loss applicable) income available to the Company's common stockholders and the Company's basic (loss) earnings per share calculation for the Predecessor 2016 Period and years ended December 31, 2015 and 2014 are presented in the accompanying consolidated statements of operations.

See Note 19 for discussion of the Company's (loss) earnings per share calculation.

Common Stock. As discussed in Note 1, on the Emergence Date the Company’s authorized common stock was canceled and released under the Plan without receiving any recovery on account thereof.

In June 2015, the Company's stockholders approved an amendment to the Company's Certificate of Incorporation, to increase the number of shares of capital stock the Company is authorized to issue from 850.0 million (800.0 million shares of common stock and 50.0 million shares of preferred stock), par value $0.001 to 1.85 billion (1.80 billion shares of common stock and 50.0 million shares of preferred stock), par value $0.001. The Company had 2.1 million shares of common stock held in treasury at December 31, 2015.

Redemption of Senior Unsecured Notes. During the year ended December 31, 2015, the Company issued approximately 28.0 million shares of common stock in exchange for $50.0 million in Senior Unsecured Notes. See Note 11 for additional discussion of the redemption of Senior Unsecured Notes.

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

Conversions of Convertible Senior Unsecured Notes. During the Predecessor 2016 Period and year ended December 31, 2015, the Company issued approximately 84.4 million and 92.8 million shares, respectively, of common stock upon the exercise of conversion options by holders of approximately $232.1 million and $255.3 million in par value, respectively, of the Convertible Senior Unsecured Notes. The Company recorded the issuance of common shares at fair value on the various dates the exchanges occurred. See Note 11 for additional discussion of the Convertible Senior Unsecured Notes transactions.

See Note 16 for discussion of the Company’s share-based compensation.

Treasury Stock. The following table shows the number of shares withheld for taxes and the associated value of those shares (in thousands). These shares were accounted for as treasury stock when withheld, and then immediately retired.

	Predecessor Period from January 1, 2016 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Number of shares withheld for taxes	1,122	1,872	1,034
Value of shares withheld for taxes	$44	$ 2,428	$ 6,373

Prior to the Emergence Date, shares of Predecessor Company common stock held as assets in a trust for the Company’s non-qualified deferred compensation plan were accounted for as treasury shares. These shares were not included as outstanding shares of common stock for accounting purposes, and were canceled on the Emergence Date. No further matching contributions will be made to the non-qualified deferred compensation plan by the Successor Company.

Stockholder Receivable. The Predecessor Company was party to a settlement agreement relating to a third-party claim against its former CEO under Section 16(b) of the Securities Exchange Act of 1934, as amended. At December 31, 2015, the remaining $1.3 million receivable related to this settlement was classified as a component of additional paid-in capital in the accompanying consolidated balance sheet. In accordance with the Plan, the remaining balance of this receivable was fully discharged on the Emergence Date.

16. Share-Based Compensation

As discussed in Note 1, the Predecessor Company’s common stock was canceled and New Common Stock was issued on the Emergence Date. Accordingly, the Predecessor Company's then existing share-based compensation awards were also canceled, which resulted in the recognition of any previously unamortized expense related to the canceled awards on the date of cancellation. Share based compensation for the Predecessor and Successor periods are not comparable.

Successor Share-Based Compensation

Omnibus Incentive Plan. Pursuant to terms of the Plan, the SandRidge Energy, Inc. 2016 Omnibus Incentive Plan (the “Omnibus Incentive Plan”) became effective on the Emergence Date.

The Successor Company's board of directors or any committee duly authorized thereby, will administer the Omnibus Incentive Plan. The committee has broad authority under the Omnibus Incentive Plan to, among other things: (i) select participants; (ii) determine the types of awards that participants are to receive and the number of shares that are to be subject to such awards; and (iii) establish the terms and conditions of awards, including the price (if any) to be paid for the shares or the award.

Persons eligible to receive awards under the Omnibus Incentive Plan include non-employee directors, employees of the Successor Company or any of its affiliates, and certain consultants and advisors to the Successor Company or any of its affiliates. The types of awards that may be granted under the Omnibus Incentive Plan include stock options, restricted stock, performance awards and other forms of awards granted or denominated in shares of New Common Stock, as well as certain cash-based awards.

The maximum number of shares of New Common Stock that may be issued or transferred pursuant to awards under the Omnibus Incentive Plan is approximately 4.6 million. If any stock option or other stock-based award granted under the Omnibus Incentive Plan expires, terminates or is canceled for any reason without having been exercised in full, the number of shares of New Common Stock underlying any unexercised award shall again be available for the purpose of awards under the Omnibus Incentive Plan. If any shares of restricted stock, performance awards or other stock-based awards denominated in shares of New Common Stock awarded under the Plan are forfeited for any reason, the number of forfeited shares shall again be available for purposes of awards under the Omnibus Incentive Plan. Any award under the Omnibus Incentive Plan settled in cash shall not be counted against the maximum share limitation.

As is customary in incentive plans of this nature, each share limit and the number and kind of shares available under the Omnibus Incentive Plan and any outstanding awards, as well as the exercise or purchase prices of awards, and performance targets under certain types of performance-based awards, are subject to adjustment in the event of certain reorganizations, mergers, combinations, recapitalizations, stock splits, stock dividends or other similar events that change the number or kind of shares outstanding, and extraordinary dividends or distributions of property to the Company's stockholders.

Restricted Common Stock Awards. During October 2016, awards for approximately 1.4 million shares of restricted stock were granted under the Omnibus Incentive Plan. These restricted shares will vest over a three year period. The Successor Company recognized share-based compensation expense of $6.6 million, net of $0.3 million capitalized, for the Successor 2016 Period. Additionally, share-based compensation expense for the Successor 2016 Period includes $4.3 million for the accelerated vesting of 0.2 million restricted common stock awards related to the Successor Company's reduction in workforce during the fourth quarter of 2016. The following table presents a summary of the Successor Company's unvested restricted stock awards.

	Number of Shares	Weighted-Average Grant Date Fair Value
	(In thousands)	
Unvested restricted shares outstanding at October 1, 2016	—	$ —
Granted	1,448	$ 24.32
Vested	(14)	$ 24.32
Forfeited / Canceled	(27)	$ 24.32
Unvested restricted shares outstanding at December 31, 2016	1,407	$ 24.32

As of December 31, 2016, the Successor Company's unrecognized compensation cost related to unvested restricted stock awards was $27.1 million. The remaining weighted-average contractual period over which this compensation cost may be recognized is 2.8 years. The Successor Company's restricted stock awards are equity-classified awards.

Predecessor Share-Based Compensation

Restricted Common Stock Awards. The Predecessor Company's restricted common stock awards generally vested over a four-year period, subject to certain conditions, and were valued based upon the market value of the common stock on the date of grant. The following table presents a summary of the Predecessor Company's unvested restricted stock awards.

	Number of Shares	Weighted-Average Grant Date Fair Value
	(In thousands)	
Unvested restricted shares outstanding at December 31, 2013	7,643	$ 6.92
Granted	6,367	$ 6.17
Vested	(3,432)	$ 7.04
Forfeited / Canceled	(2,022)	$ 6.60
Unvested restricted shares outstanding at December 31, 2014	8,556	$ 6.39

Granted	2,928		$	0.88
Vested	(5,186	)	$	4.95
Forfeited / Canceled	(672	)	$	6.38
Unvested restricted shares outstanding at December 31, 2015	5,626		$	4.85
Granted	—		$	—
Vested	(3,034	)	$	5.34
Forfeited / Canceled	(2,592	)	$	4.31
Predecessor ending unvested restricted shares at October 1, 2016	—		$	—

The Predecessor Company issued share-based compensation awards including restricted common stock awards, restricted stock units, performance units and performance share units under the SandRidge Energy, Inc. 2009 Incentive Plan, (the “2009 Plan”). Total share-based compensation expense was measured using the grant date fair value for equity-classified awards and using the fair value at period end for liability-classified awards. The Predecessor Company recognized share-based compensation expense of $11.2 million, net of $1.7 million capitalized, for the Predecessor 2016 Period, and $21.7 million and $22.6 million, net of $5.9 million and $6.0 million capitalized for the years ended December 31, 2015 and 2014, respectively. Share-based compensation expense for the Predecessor 2016 Period includes $5.4 million for the accelerated vesting of 1.3 million restricted common stock awards related to the Predecessor Company’s reduction in workforce during the first quarter of 2016. There was no significant activity related to the Predecessor Company’s outstanding unvested restricted stock units, performance units and performance share units during the Predecessor 2016 Period.

In conjunction with the cancellation of the Predecessor Company’s common stock and termination of the 2009 Plan on the Emergence Date, the unrecognized compensation cost related to the Predecessor Company’s unvested restricted common stock awards of $5.9 million was expensed.

17. Incentive and Deferred Compensation Plans

Performance Incentive Plan. In January 2016, the Company implemented a performance incentive plan. The plan replaced, on a prospective basis, the Company’s previous annual incentive plan, including long-term incentive awards, and provided for quarterly cash payments at a target percentage to participants based upon corporate performance goals with aggregate annual payout opportunity ranging from 0% to 200%. The first three quarterly cash payments were limited to no greater than target payouts with a cash make up payment for above target performance based on the Company’s annual performance results to be made in the first quarter of 2017. Under this plan, the Predecessor Company paid out approximately $17.8 million during the first two quarters of 2016 and the Successor Company paid out approximately $7.1 million during the fourth quarter of 2016, with approximately $15.8 million accrued at December 31, 2016 for payment in the first quarter of 2017.

Annual Incentive Plan. Prior to January 2016, for certain members of management, the annual incentive plan incorporated objective performance criteria, individual performance goals and competitive target award levels for the 2015 performance year with payout percentages ranging from 0% to 200% of specified target levels based on actual performance. As of December 31, 2015, the Company had accrued approximately $21.6 million for the annual incentive for all employees, including an accrual for an annual incentive for specified members of management based on actual performance compared to target levels specified in the annual incentive plan, which was paid in the first quarter of 2016.

Deferred Compensation Plans. The Company maintains a 401(k) retirement plan for its employees. Under this plan, eligible employees may elect to defer a portion of their earnings up to the maximum allowed by Internal Revenue Service (“IRS”) regulations. For the Successor 2016 Period, the Successor Company made matching cash contributions to the plan equal to 100% on the first 10% employee deferred wages for the period totaling $0.9 million. For the Predecessor 2016 Period, the Predecessor Company made matching cash contributions to the plan equal to 100% on the first 10% employee deferred wages for the period totaling $4.9 million. For the years ended December 31, 2015 and 2014, the Predecessor Company made matching contributions to the plan through cash purchases of Predecessor Company stock equal to 100% on the first 10% employee deferred wages. Retirement plan expense for the years ended December 31, 2015 and 2014 was approximately $7.9 million and $8.7 million, respectively. Participants in the plan are immediately 100% vested in the discretionary employee contributions and related earnings on those contributions. The Company's matching contributions and related earnings vest based on years of service, with full vesting occurring on the fourth anniversary of employment.

The Company maintains a non-qualified deferred compensation plan that allowed eligible highly compensated employees to elect to defer income exceeding the IRS annual limitations on qualified 401(k) retirement plans through December 31, 2016. The Predecessor Company made insignificant matching contributions on non-qualified contributions for the Successor 2016 Period, the Predecessor 2016 Period and years ended December 31, 2015 and 2014. On December 31, 2016, the Successor Company began the process of terminating the non-qualified deferred compensation plan. No employee or employer contributions will be made to the plan after December 31, 2016 and in accordance with the plan termination procedures, the remaining assets held in the plan, of approximately $7.5 million as of December 31, 2016, will be fully distributed to participating employees throughout 2017 and the first quarter of 2018.

Any assets placed in trust by the Company to fund future obligations of the Company’s non-qualified deferred compensation plan are subject to the claims of creditors in the event of insolvency or bankruptcy, and participants are general creditors of the Company as to their own deferred compensation in, and the Company’s contributions to, the plan.

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

18. Income Taxes

The Company's income tax provision (benefit) consisted of the following components (in thousands):

	Successor Period from October 2, 2016 through December 31, 2016	Predecessor Period from January 1, 2016 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Current				
Federal	$ —	$—	$ —	$ (1,160)
State	9	11	123	(1,133)
	9	11	123	(2,293)
Deferred				
Federal	—	—	—	—
State	—	—	—	—
	—	—	—	—
Total provision (benefit)	9	11	123	(2,293)
Less: income tax provision attributable to noncontrolling interest	—	—	90	283
Total provision (benefit) attributable to SandRidge Energy, Inc.	$ 9	$11	$ 33	$ (2,576)

A reconciliation of the provision (benefit) for income taxes at the statutory federal tax rate to the Company's actual income tax provision (benefit) is as follows (in thousands):

	Successor Period from October 2, 2016 through December 31, 2016	Predecessor Period from January 1, 2016 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Computed at federal statutory rate	$(116,891)	$504,283	$(1,512,325)	$122,362
State taxes, net of federal benefit	(3,696)	10,512	(19,988)	4,145
Non-deductible expenses	144	462	816	1,895
Non-deductible debt costs	—	22,694	10,228	—
Stock-based compensation	306	5,884	6,700	1,467
Net effects of consolidating the non-controlling interests' tax provisions	—	—	218,196	(34,614)
Discharge of debt and other reorganization related items	—	359,278	—	—
Change in valuation allowance	120,144	(903,102)	1,296,405	(96,769)
Other	2	—	1	(1,062)
Total provision (benefit) attributable to SandRidge Energy, Inc.	$9	$11	$33	$(2,576)

Deferred income taxes are provided to reflect the future tax consequences of temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements. The Company's deferred tax assets have been reduced by a valuation allowance due to a determination made that it is more likely than not that some or all of the deferred assets will not be realized based on the weight of all available evidence. As of December 31, 2016, 2015 and 2014 the balance of the valuation allowance was $1.1 billion, $2.0 billion, and $649.6 million, respectively. The Company continues to closely monitor and weigh all available evidence, including both positive and negative, in making its determination whether to maintain a valuation allowance. As a result of the significant weight placed on the Company's cumulative negative earnings position, the Company continued to maintain the full valuation allowance against its net deferred tax asset at December 31, 2016. Thus, the Company's effective tax rate and tax expense for the Successor 2016 Period and Predecessor 2016 Period continue to be low as a result of the Company not recognizing an income tax benefit associated with its net (loss) income from the same periods.

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

Significant components of the Company's deferred tax assets and liabilities are as follows (in thousands):

	Successor December 31, 2016	Predecessor December 31, 2015
Deferred tax liabilities		
Investments(1)	$ 275,128	$ 138,310
Derivative contracts	—	30,989
Long-term debt	—	10,017
Total deferred tax liabilities	275,128	179,316
Deferred tax assets		
Property, plant and equipment	751,683	807,275
Derivative contracts	11,274	—
Allowance for doubtful accounts	1,487	18,702
Net operating loss carryforwards	527,079	1,190,799
Compensation and benefits	14,494	18,607
Alternative minimum tax credits and other carryforwards	43,770	44,302
Asset retirement obligations	40,399	38,314
CO_2 under-delivery shortfall penalty	—	40,654
Other	4,663	4,305
Total deferred tax assets	1,394,849	2,162,958
Valuation allowance	(1,119,721)	(1,983,642)
Net deferred tax liability	$ —	$ —

(1) Includes the Company's deferred tax liability resulting from its investment in the Royalty Trusts.

Internal Revenue Code ("IRC") Section 382 addresses company ownership changes and specifically limits the utilization of certain deductions and other tax attributes on an annual basis following an ownership change. As discussed in Note 1, on the Emergence Date the Company's existing convertible perpetual preferred stock and the Company's common stock were canceled and New Common Stock was issued resulting in the Company experiencing an ownership change under IRC Section 382. Further, certain of the transactions that occurred upon the Company's emergence from bankruptcy on October 4, 2016 materially impacted the Company's tax attributes. Cancellation of indebtedness income resulting from these transactions reduced the Company's tax attributes, including but not limited to federal net operating loss carryforwards, in the amount of $3.7 billion. The Company analyzed alternatives available within the IRC to taxpayers in Chapter 11 bankruptcy proceedings in order to minimize the impact of the October 4, 2016 ownership change and cancellation of indebtedness income on its tax attributes. Upon filing its 2016 U.S. Federal income tax return, the Company plans to elect an available alternative that does not subject existing tax attributes to an IRC Section 382 limitation. However, should an additional ownership change become likely to occur prior to filing its 2016 U.S. Federal income tax return, the Company will evaluate the remaining available alternative which would likely result in the Company experiencing a limitation that subjects existing tax attributes at emergence to an IRC Section 382 limitation which could result in some or all of the remaining net operating loss carryforwards expiring unused. The ownership change did not result in a current federal tax liability at December 31, 2016.

As of December 31, 2016, the Company had approximately $9.3 million of alternative minimum tax credits available that do not expire. In addition, the Company had approximately $1.3 billion of federal net operating loss carryovers after attribute reduction resulting from cancellation of indebtedness that expire during the years 2028 through 2036.

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

At December 31, 2016 and 2015, the Company had a liability of approximately $0.1 million for unrecognized tax benefits. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows (in thousands):

	Successor	Predecessor	
	Period from October 2, 2016 through December 31, 2016	Period from January 1, 2016 through October 1, 2016	Year Ended December 31, 2015
Unrecognized tax benefit at January 1	$ 81	$ 81	$ 77
Changes to unrecognized tax benefits related to a prior year	3	—	4
Unrecognized tax benefit at December 31	$ 84	$ 81	$ 81

Consistent with its policy to record interest and penalties on income taxes as a component of the income tax provision, the Company has included insignificant amounts of accrued gross interest with respect to unrecognized tax benefits in its accompanying consolidated statements of operations during the years ended December 31, 2016, 2015 and 2014. The Company does not expect a significant change in its gross unrecognized tax benefits balance within the next 12 months.

The Company’s only taxing jurisdiction is the United States (federal and state). The Company’s tax years 2013 to present remain open for federal examination. Additionally, tax years 2005 through 2012 remain subject to examination for the purpose of determining the amount of federal net operating loss and other carryforwards. The number of years open for state tax audits varies, depending on the state, but are generally from three to five years.

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

19. (Loss) Earnings per Share

As discussed in Note 1, on the Emergence Date, the Predecessor Company’s then-authorized common stock was canceled, the New Common Stock and Warrants were issued and the Omnibus Incentive Plan became effective.

The following table summarizes the calculation of weighted average common shares outstanding used in the computation of diluted (loss) earnings per share:

	Net (Loss) Income	Weighted Average Shares	(Loss) Earnings Per Share
	(In thousands, except per share amounts)		
Period from October 2, 2016 to December 31, 2016 (Successor)			
Basic loss per share	$(333,982)	18,967	$(17.61)
Effect of dilutive securities			
Restricted stock(1)	—	—	
Warrants(1)	—	—	
New Convertible Notes(2)	—	—	
Diluted loss per share	$(333,982)	18,967	$(17.61)
Period from January 1, 2016 to October 1, 2016 (Predecessor)			
Basic earnings per share	$1,424,476	708,928	$2.01
Effect of dilutive securities			
Restricted stock and units(3)	—	—	
Diluted earnings per share	$1,424,476	708,928	$2.01
Year Ended December 31, 2015 (Predecessor)			
Basic loss per share	$(3,735,495)	521,936	$(7.16)
Effect of dilutive securities			
Restricted stock and units(3)	—	—	
Convertible preferred stock(4)	—	—	
Convertible senior unsecured notes(5)	—	—	
Diluted loss per share	$(3,735,495)	521,936	$(7.16)
Year Ended December 31, 2014 (Predecessor)			
Basic earnings per share	$203,260	479,644	$0.42
Effect of dilutive securities			
Restricted stock	—	2,181	
Convertible preferred stock(4)	6,500	17,918	
Diluted earnings per share	$209,760	499,743	$0.42

(1) No incremental shares of potentially dilutive restricted stock awards or warrants were included for the Successor 2016 Period as their effect was antidilutive.

(2) Potential common shares related to the New Convertible Notes covering 14.6 million shares for the Successor 2016 Period were excluded from the computation of loss per share because their effect would have been antidilutive under the if-converted method.

(3) No incremental shares of potentially dilutive restricted stock awards or units were included for the Predecessor 2016 Period and the year ended December 31, 2015 as their effect was antidilutive under the treasury stock method.

(4) Potential common shares related to the Predecessor Company's then-outstanding 8.5% and 7.0% convertible perpetual preferred stock covering 71.2 million and 71.7 million shares for the years ended December 31, 2015 and 2014, respectively, were excluded from the computation of (loss) earnings per share because their effect would have been antidilutive under the if-converted method.

(5) Potential common shares related to the Predecessor Company's then-outstanding 8.125% and 7.5% Convertible Senior Unsecured Notes covering 48.5 million shares for the year ended December 31, 2015 were excluded from the computation of loss per share because their effect would have been antidilutive under the if-converted method.

See Note 15 for discussion of the Predecessor Company's convertible perpetual preferred stock. The remaining outstanding New Convertible Notes were converted into shares of New Common Stock as a result of the Company's entry into the refinanced credit facility on February 10, 2017. For further discussion see Note 21.

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

20. Related Party Transactions

The Company entered into transactions in the ordinary course of business with certain related parties. These transactions primarily consisted of sales of oil and natural gas. See Note 10 for accounts payable attributable to related party transactions.

2014 Divestiture. See Note 5 for discussion of the sale of the Gulf Properties to Fieldwood and the Company's guarantee on behalf of Fieldwood of certain associated plugging and abandonment obligations associated with the Gulf Properties. Fieldwood is a portfolio company of Riverstone Holdings LLC, affiliates of which owned a significant number of shares of the Predecessor Company's common stock at the time the transaction occurred.

21. Subsequent Events

Acquisition of Properties. On February 10, 2017, the Company acquired approximately 13,000 net acres in Woodward County, Oklahoma for approximately $47.8 million in cash. Also included in the acquisition were working interests in 4 wells previously drilled on the acreage.

Refinancing of New First Lien Exit Facility. On February 10, 2017, the New First Lien Exit Facility was refinanced into a new $600.0 million credit facility with a $425.0 million borrowing base. The amended credit facility agreement had the following impacts:

- increased the principal amount of commitments to $600.0 million from $425.0 million;
- extended the maturity date to March 31, 2020 from February 4, 2020;
- borrowing base determinations now include the Company's proportionately consolidated share of proved reserves held by the Royalty Trusts;
- reduced the interest rate from a flat base rate of LIBOR plus 4.75% per annum to a pricing grid tied to borrowing base utilization of (A) LIBOR plus an applicable margin that varies from 3.00% to 4.00% per annum, or (B) the base rate plus an applicable margin that varies from 2.00% to 3.00% per annum;
- reduced the LIBOR floor from 1% to 0%;
- eliminated the minimum proved developing producing reserves asset coverage ratio;
- removed the requirement to maintain $50.0 million in a cash collateral account controlled by the administrative agent;
- eliminated the holiday from borrowing base determinations and the maximum consolidated total net leverage ratio and the minimum consolidated interest coverage ratio covenants; and
- eliminated certain negative covenants, such as the $20.0 million liquidity requirement and the limitation on capital expenditures.

Conversions of New Convertible Notes to New Common Stock. During the period from January 1, 2017 to February 9, 2017, holders of approximately $5.1 million in aggregate principal amount of the New Convertible Notes exercised conversion options applicable to those notes, resulting in the issuance of approximately 0.3 million shares of New Common Stock.

In conjunction with the refinancing of the New First Lien Exit Facility that took place on February 10, 2017, the remaining $263.7 million par value of the New Convertible Notes mandatorily converted into approximately 14.1 million shares of New Common Stock.

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

22. Supplemental Information on Oil and Natural Gas Producing Activities (Unaudited)

The supplemental information includes capitalized costs related to oil and natural gas producing activities; costs incurred in oil and natural gas property acquisition, exploration and development; and the results of operations for oil and natural gas producing activities. Supplemental information is also provided for oil, natural gas and NGL production and average sales prices; the estimated quantities of proved oil, natural gas and NGL reserves; the standardized measure of discounted future net cash flows associated with proved oil, natural gas and NGL reserves; and a summary of the changes in the standardized measure of discounted future net cash flows associated with proved oil, natural gas and NGL reserves.

Capitalized Costs Related to Oil and Natural Gas Producing Activities

The Company's capitalized costs for oil and natural gas activities consisted of the following (in thousands):

	Successor	Predecessor	
	December 31,	December 31,	
	2016	2015	2014
Oil and natural gas properties			
Proved	$ 840,201	$12,529,681	$11,707,147
Unproved	74,937	363,149	290,596
Total oil and natural gas properties	915,138	12,892,830	11,997,743
Less accumulated depreciation, depletion and impairment	(353,030)	(11,149,888)	(6,359,149)
Net oil and natural gas properties capitalized costs	$ 562,108	$1,742,942	$5,638,594

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

Costs incurred in oil and natural gas property acquisition, exploration and development activities which have been capitalized are summarized as follows (in thousands):

	Successor	Predecessor		
	Period from October 2, 2016 through December 31, 2016	Period from January 1, 2016 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Acquisitions of properties				
Proved	$ 5,142	$3,897	$ 35,376	$73,370
Unproved	5,491	1,899	210,065	123,649
Exploration(1)	—	1,234	29,297	41,070
Development	27,429	149,924	571,562	1,288,395
Total cost incurred	$ 38,062	$156,954	$ 846,300	$1,526,484

(1) Includes seismic costs of $7.1 million and $10.8 million for the years ended December 31, 2015 and 2014, respectively.

SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements - (Continued)

Results of Operations for Oil and Natural Gas Producing Activities

The Company’s results of operations from oil and natural gas producing activities are shown in the following table (in thousands):

	Successor Period from October 2, 2016 through December 31, 2016	Predecessor Period from January 1, 2016 through October 1, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Revenues	$ 98,307	$279,971	$ 707,434	$1,420,879
Expenses				
Production costs	27,640	135,715	324,141	377,819
Depreciation and depletion	33,971	86,613	319,913	434,295
Accretion of asset retirement obligations	2,090	4,365	4,477	9,092
Impairment	319,087	657,392		