UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2020
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.)**
1 E. Sheridan Ave, Suite 500 Oklahoma City, Oklahoma	**73104**
(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	Trading Symbol	Name of each exchange on which registered
Common Stock, $0.001 par value	SD	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 ☑

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 ☑

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 ☑ No ☐

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

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

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

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

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7276(b)) by the registered public accounting firm that prepared or issued its audit report. ☐

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

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2020 was approximately $39.5 million based on the closing price as quoted on the New York Stock Exchange. As of February 25, 2021, there were 36,135,055 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company's definitive proxy statement for the 2021 Annual Meeting of Stockholders, which will be filed with the SEC within 120 days of December 31, 2020, are incorporated by reference in Part III.

SANDRIDGE ENERGY, INC.
2020 ANNUAL REPORT ON FORM 10-K
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GLOSSARY OF TERMS

References in this report to the "Company," "SandRidge," "we," "our," and "us" mean SandRidge Energy, Inc., including its consolidated subsidiaries and variable interest entities of which it is the primary beneficiary. In addition, the following is a description of the meanings of certain terms used in this report.

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

ASC. Accounting Standards Codification.

ASU. Accounting Standards Update.

Bankruptcy Code. United States Bankruptcy Code.

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

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

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

Bench. A geological horizon; a distinctive stratum useful for stratigraphic correlation.

Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil. Although an equivalent barrel of condensate or natural gas may be equivalent to a barrel of oil on an energy basis, it is not equivalent on a value basis as there may be a large difference in value between an equivalent barrel and a barrel of oil. For example, based on the commodity prices used to prepare the estimate of the Company's reserves at year-end 2020 of $39.57/Bbl for oil and $1.99/Mcf for natural gas, the ratio of economic value of oil to natural gas was approximately 22 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.

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

CO_2. Carbon dioxide.

Completion. The process of treating a drilled well, primarily through hydraulic fracturing, followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry well, the reporting to the appropriate authority that the well has been abandoned.

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

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

Developed acreage. The number of acres that are assignable to productive wells.

Developed oil, natural gas and NGL reserves. Reserves of any category that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development costs. Costs incurred to obtain access to proved reserves, complete wells and provide facilities for extracting, treating, gathering and storing the oil and natural gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to (i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building and relocating public roads, gas lines and power lines, to the extent necessary in developing the proved reserves, (ii) drill, equip and complete development wells, development-type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly, (iii) acquire, construct and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems, and (iv) provide improved recovery systems.

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry well. An exploratory, development or extension well that proves to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

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

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

ERISA. Employee Retirement Income Security Act of 1974.

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

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to produce oil or natural gas in another reservoir.

Extended-reach lateral (“XRL”). Extended-reach lateral wells are horizontal wells where the horizontal segment or lateral is at least approximately 9,000-9,500 feet in length and may extend further. When referencing lateral counts, XRL’s are counted as more than one lateral depending on the relationship of length to an SRL length. E.g. a 9,000 foot lateral would be counted as two laterals.

FASB. Financial Accounting Standards Board.

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

Horizontal well. A well that is turned horizontally at depth, providing access to oil and gas reserves at a wide range of angles.

Hydraulic fracturing. Procedure to stimulate production by forcing a mixture of fluid and proppant into the formation under high pressure. Hydraulic fracturing creates artificial fractures in the reservoir rock to increase permeability and porosity.

IRS. Internal Revenue Service.

Lease. A contract in which the owner of minerals gives a company or working interest owner temporary and limited rights to explore for, develop, and produce minerals from the property, or; any transfer where the owner of a mineral interest assigns all or a part of the operating rights to another party but retains a continuing nonoperating interest in production from the property.

MBbls. Thousand barrels of oil or other liquid hydrocarbons.

MBoe. Thousand barrels of oil equivalent.

Mcf. Thousand cubic feet of natural gas.

MMBbls. Million barrels of oil or other liquid hydrocarbons.

MMBoe. Million barrels of oil equivalent.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

MMcf/d. MMcf per day.

Mississippian Trust I. SandRidge Mississippian Trust I.

Mississippian Trust II. SandRidge Mississippian Trust II.

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

*New Credit Facility. C*redit facility dated November 30, 2020.

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

NYMEX. The New York Mercantile Exchange.

NYSE. New York Stock Exchange.

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

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%.

Prior Credit Facility. Senior credit facility dated February 10, 2017, as subsequently amended.

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

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

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

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

Proved oil, natural gas and NGL reserves. Those quantities of oil, natural gas and NGLs which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

For additional information, see the SEC's definition in Rule 4-10(a) (22) of Regulation S-X, a link for which is available at the SEC's website.

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

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

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

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

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

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

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

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

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

Ryder Scott. Ryder Scott Company, L.P.

SEC. Securities and Exchange Commission.

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

Securities Act. Securities Act of 1933, as amended.

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

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

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

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

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

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

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

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

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

Cautionary Note Regarding Forward-Looking Statements

This report includes "forward-looking statements" as defined by the SEC. These forward-looking statements may include projections and estimates concerning our capital expenditures, liquidity, capital resources and debt profile, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, elements of our business strategy, compliance with governmental regulation of the oil and natural gas industry, including environmental regulations, acquisitions and divestitures and the potential effects on our financial condition and other statements concerning our operations, financial performance and financial condition. Forward-looking statements are generally accompanied by words such as “estimate,” “assume,” “target,” “project,” “predict,” “believe,” “expect,” “anticipate,” “potential,” “could,” “may,” “foresee,” “plan,” “goal,” “should,” “intend” or other words that convey the uncertainty of future events or outcomes. These forward-looking statements are based on certain assumptions and analyses based on our experience and perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Such statements are not guarantees of future performance and actual results or developments may differ materially from those projected. The Company disclaims any obligation to update or revise these forward-looking statements unless required by law, and cautions readers not to rely on them unduly. While we consider these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties relating to, among other matters, the risks and uncertainties discussed in “Risk Factors” in Item 1A of this report, as well as the following:

- the impact of the COVID-19 pandemic and the effects thereof;
- risks associated with drilling oil and natural gas wells;
- the volatility of oil, natural gas and NGL prices;
- uncertainties in estimating oil, natural gas and NGL reserves;
- the need to replace the oil, natural gas and NGL reserves the Company produces;
- our ability to execute our growth strategy by drilling wells as planned;
- the amount, nature and timing of capital expenditures, including future development costs, required to develop our undeveloped areas;
- concentration of operations in the Mid-Continent region of the United States;
- limitations of seismic data;
- the potential adverse effect of commodity price declines on the carrying value of our oil and natural properties;
- severe or unseasonable weather that may adversely affect production;
- availability of satisfactory oil, natural gas and NGL marketing and transportation options;
- availability and terms of capital to fund capital expenditures;
- amount and timing of proceeds of asset monetizations;
- potential financial losses or earnings reductions from commodity derivatives;
- potential elimination or limitation of tax incentives;
- risks and uncertainties related to the adoption and implementation of regulations restricting oil and gas development in states where we operate;
- competition in the oil and natural gas industry;
- general economic conditions, either internationally or domestically affecting the areas where we operate;
- costs to comply with current and future governmental regulation of the oil and natural gas industry, including environmental, health and safety laws and regulations, and regulations with respect to hydraulic fracturing and the disposal of produced water; and
- the need to maintain adequate internal control over financial reporting.

PART I

Item 1. *Business*

GENERAL

We are an independent oil and natural gas company, organized in 2006, with a principal focus on acquisition, development and production activities in the U.S. Mid-Continent and North Park Basin of Colorado. Prior to February 5, 2021, we held assets in the North Park Basin of Colorado, which have been sold in their entirety.

As of December 31, 2020, we had an interest in 1,442 gross (837.0 net) producing wells, approximately 967 of which we operate, and approximately 666,000 gross (470,000 net) total acres under lease. As of December 31, 2020, we had no rigs drilling. Total estimated proved reserves as of December 31, 2020, were 36.9 MMBoe, of which 100% were proved developed.

Our principal executive offices are located at 1 E. Sheridan Ave, Suite 500, Oklahoma City, Oklahoma 73104 and our telephone number is (405) 429-5500. Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports are made available free of charge on our website at www.sandridgeenergy.com as soon as reasonably practicable after we file such material with, or furnish it to, the SEC. Any materials that we have filed with the SEC may be accessed via the SEC's website address at *www.sec.gov*.

Reorganization Under Chapter 11 and Emergence from Bankruptcy

On May 16, 2016, the Debtors filed Bankruptcy Petitions for reorganization under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court. The Bankruptcy Court confirmed the reorganization plan, and the Debtors' subsequently emerged from bankruptcy on October 4, 2016. Pursuant to the reorganization plan, all of the Predecessor Company's common stock and other equity and debt securities were cancelled and on October 4, 2016, the Successor Company issued an aggregate of 18.9 million shares of common stock at $.001 par value and commenced trading on the New York Stock Exchange.

Our Business Strategy

Our business strategy in 2021 will be focused on optimizing the cash return on our assets through a continued focus on cost and capital discipline, limiting our development capital expenditures to locations that we believe will provide high rates of return in the present commodity price environment and that allow for near-term payouts. We will continue our pursuit of acquisitions and business combinations that are accretive to economic value and debt-adjusted cash flow per share, and which provide high margin properties with attractive returns at current commodity prices. We will continue to exercise financial discipline and prudent capital allocation, and we will seek to use our net operating loss carry forwards to minimize income taxes and maximize cash flow.

PRIMARY BUSINESS OPERATIONS

Our primary operations are the development and acquisition of hydrocarbon resources. The following table presents information concerning our operations by geographic area as of December 31, 2020.

	Estimated Proved Reserves (MMBoe) (1)	Daily Production (MBoe/d)(2)	Reserves/ Production (Years)(3)	Gross Acreage	Net Acreage	Capital Expenditures (In millions) (4)
Area						
Mid-Continent	33.4	19.1	4.8	568,062	380,031	$ 6.8
North Park Basin	3.5	1.8	5.3	97,657	89,666	1.5
Total	36.9	20.9	10.1	665,719	469,697	$ 8.3

(1) Estimated proved reserves were determined using SEC prices, and do not reflect actual prices received or current market prices. All prices are held constant throughout the lives of the properties. The index prices and the equivalent weighted average wellhead prices used in the reserve reports are shown in the table below.
(2) Average daily net production for the month of December 2020.
(3) Estimated proved reserves as of December 31, 2020 divided by average daily net production for the month of December 2020, annualized.
(4) Capital expenditures for the year ended December 31, 2020, on an accrual basis and including acquisitions.

Properties

Mid-Continent

We held interests in approximately 568,000 gross (380,000 net) leasehold acres located in Oklahoma and Kansas at December 31, 2020. Associated proved reserves at December 31, 2020 totaled 33.4 MMBoe, 100.0% of which were proved developed reserves. Our interests in the Mid-Continent as of December 31, 2020 included 1,394 gross (789.0 net) producing wells with an average working interest of 57%. The interests are largely aggregated across the Mississippian Lime, Meramec and Osage formations. The Mississippian Lime formation is an expansive carbonate hydrocarbon system located on the Anadarko Shelf in northern Oklahoma and southern Kansas. The top of this formation is encountered between approximately 4,000 and 7,000 feet and stratigraphically between various formations of Pennsylvanian age and the Devonian-aged Woodford Shale formation. The Mississippian formation is approximately 350 to 650 feet in gross thickness across our lease position and has targeted porosity zone(s) ranging between 20 and 150 feet in thickness. The Meramec and Osage Formations are Mississippian in age, lying above the Woodford Shale and below Chester formations. The Meramec is composed of interbedded shales, sands, and carbonates while the Osage is composed of low porosity, fractured limestone and chert. The top of these target formations ranges in depth from about 5,800 feet at the northern edge of the basin to greater than 14,000 feet toward the interior of the basin. Meramec formation thickness ranges from about 50 feet to over 400 feet and the Osage formation thickness ranges from about 450 to 1,400 feet. The Woodford Shale is the primary hydrocarbon source for both the Meramec and Osage. During 2020, we did not have any drilling activity in the Mid-Continent.

North Park Basin

Prior to February 5, 2021, we held assets in the North Park Basin, which have been sold in their entirety. Our North Park Basin properties consisted of approximately 98,000 gross (90,000 net) acres, and 48 gross and net producing wells with a working interest of 100%, at December 31, 2020. Associated proved reserves at December 31, 2020 totaled approximately 3.5 MMBoe, of which 100% were proved developed reserves. The North Park Basin acreage is located in north central Colorado, and similar to the DJ Basin next to Colorado's Front Range, has multiple potential pay targets in addition to the Niobrara Shale play, where our activity was focused. Although untested, zones shallower and deeper than the Niobrara have indications of potentially commercial hydrocarbons. The Niobrara Shale is characterized by stacked pay benches at depths of 5,500 to 9,000 feet with overall reservoir thickness over 450 feet. During 2020, we did not have any drilling activity in North Park Basin.

Proved Reserves

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

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

Preparation of Reserves Estimates

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

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

Along with SandRidge’s reserve engineers the Vice President of Engineering and Reservoir serves as the primary technical professional providing oversight of our reserve estimate. The reserve engineers monitor well performance and make reserve estimate adjustments as necessary to ensure the most current information is reflected.

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, SandRidge has a comprehensive SEC-compliant internal controls framework and set of policies to determine, estimate and report proved reserves including:

- confirming that we include reserves estimates for all properties owned and that they are based upon proper working and net revenue interests;
- ensuring the information provided by other departments within the Company such as Accounting is accurate;
- communicating, collaborating, and analyzing with technical personnel;
- comparing and reconciling the internally generated reserves estimates to those prepared by third parties;
- utilizing experienced reservoir engineers or those under their direct supervision to prepare reserve estimates; and
- ensuring compensation for the reserve engineers is not tied to the amount of reserves recorded.

Key reserve information is reviewed and approved at least annually by the Company's Chief Executive Officer and Chief Financial Officer.

SandRidge's reserve engineers and the Vice President of Engineering and Reservoir works closely with independent petroleum consultants at each fiscal year end to ensure the integrity, accuracy and timeliness of annual independent reserves estimates. These independently developed reserves estimates are presented to the Audit Committee. In addition to reviewing the independently developed reserve reports, the Audit Committee also periodically meets with the independent petroleum consultants that prepare estimates of proved reserves.

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

	December 31,	
	2020	2019
Cawley, Gillespie & Associates, Inc.	73.6 %	50.2 %
Ryder Scott Company, L.P.	17.9 %	43.0 %
Total	91.5 %	93.2 %

The remaining 8.5% and 6.8% of estimated proved reserves as of December 31, 2020 and 2019, respectively, were based on internally prepared estimates, primarily for the Mid-Continent area.

Copies of the reports issued by our independent reserve consultants with respect to our oil, natural gas and NGL reserves as of December 31, 2020 are filed with this report as Exhibits 99.1 and 99.2. The geographic location of our estimated proved reserves prepared by each of the independent reserve consultants as of December 31, 2020 is presented below.

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

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

Cawley, Gillespie & Associates, Inc.:

- more than 25 years of practical experience in the estimation and evaluation of petroleum reserves;
- a registered professional engineer in the state of Texas; and
- Bachelor of Science Degree in Petroleum Engineering.

Ryder Scott Company, L.P.:

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

Reporting of Natural Gas Liquids

NGLs are recovered through further processing of a portion of our natural gas production stream. At December 31, 2020, NGLs comprised approximately 30% of total proved reserves on a barrel equivalent basis and represented volumes to be produced from properties where we have contracts in place for the extraction and sale of NGLs. NGLs are products sold by the gallon. In reporting proved reserves and production of NGLs, we have included production and reserves in barrels based on a conversion rate of 42 gallons per barrel. The extraction of NGLs in the processing of natural gas reduces the volume of natural gas available for sale. The amount of NGLs extracted from produced gas can vary with individual component prices and we have limited direct control over the extent to which NGLs are extracted from our natural gas, particularly light-end components such as ethane. 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, 2020 and 2019, over 90% of which were prepared by independent reserve engineers. The reserve reports were based on our drilling schedule at the time year-end reserve estimates were prepared. See "Critical Accounting Policies and Estimates" in Item 7 of this report for further discussion of uncertainties inherent to the reserves estimates.

	December 31,	
	2020	2019
Estimated Proved Reserves (1)		
Developed		
Oil (MMBbls)	8.5	14.1
NGL (MMBbls)	11.2	14.5
Natural gas (Bcf)	102.9	200.9
Total proved developed (MMBoe)	36.9	62.1
Undeveloped		
Oil (MMBbls)	—	21.2
NGL (MMBbls)	—	1.3
Natural gas (Bcf)	—	31.5
Total proved undeveloped (MMBoe)	—	27.8
Total Proved		
Oil (MMBbls)	8.5	35.3
NGL (MMBbls)	11.2	15.9
Natural gas (Bcf)	102.9	232.3
Total proved (MMBoe)	36.9	89.9
Standardized Measure of Discounted Net Cash Flows (in millions) (2)	$ 105.0	$ 364.3
PV-10 (in millions) (3)	$ 105.0	$ 364.3

(1) Estimated proved reserves, PV-10 and Standardized Measure were determined using SEC prices, and do not reflect actual prices received or current market prices. All prices are held constant throughout the lives of the properties.

The index prices and the equivalent weighted average wellhead prices used in the reserve reports are shown in the table below:

	Index prices (a)		Weighted average wellhead prices (b)		
	Oil (per Bbl)	Natural gas (per Mcf)	Oil (per Bbl)	NGL (per Bbl)	Natural gas (per Mcf)
December 31, 2020	$ 39.57	$ 1.99	$ 36.54	$ 6.40	$ 0.87
December 31, 2019	$ 55.69	$ 2.58	$ 50.63	$ 12.45	$ 1.16

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

(2) Standardized Measure differs from PV-10 as standardized measure includes the effect of future income taxes. At December 31, 2020 and 2019, the difference between the standardized measure and PV-10 was insignificant due to an excess of tax basis in oil and natural gas properties over projected undiscounted future cash flows from our proved reserves.

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

	December 31, 2020	December 31, 2019
	(In millions)	
Standardized Measure of Discounted Net Cash Flows	$ 105.0	$ 364.3
Present value of future income tax discounted at 10%	—	—
PV-10	$ 105.0	$ 364.3

Proved Reserves - Mid-Continent. Proved reserves in the Mid-Continent, primarily the Mississippian formation, decreased from 61.4 MMBoe at December 31, 2019 to 33.4 MMBoe at December 31, 2020. This reserve reduction is due to downward revisions of 21.3 MMBoe associated with the decrease in year-end SEC commodity pricing (5.5 MMBoe from removing PUDs, and 15.8 MMBoe from remaining proved reserves), 2020 production totaling 7.8 MMBoe, and well shut-ins, sales and other revisions amounting to 8.4 MMBboe. The COVID-19 Pandemic and resulting 2020 commodity price contraction necessitated numerous operational and other cost saving initiatives. These cost saving initiatives, while value additive, sometimes resulted in changes to artificial lift, or other well performance factors that reduce forward looking projections relative to previous estimates on a subset of wells. Partially offsetting these reductions was an 8.4 MMBoe increase associated with a reduction in expenses and other commercial improvements and acquisitions of 1.1 MMBoe of proved reserves.

Proved Reserves - North Park Basin. Prior to February 5, 2021, we held assets in the North Park Basin, which have been sold in their entirety. Our North Park Basin proved reserves in the Niobrara decreased from 28.5 MMBoe at December 31, 2019 to 3.5 MMBoe at December 31, 2020. This reserve reduction is due primarily to downward revisions of 23.7 MMBoe associated with the decrease in year-end SEC commodity pricing (22.3 MMBoe from removing PUDs and 1.4 MMBoe from remaining proved reserves), 2020 production totaling 0.9 MMBoe and 0.6 MMBoe of negative revisions to prior estimates stemming from changes in well performance. Offsetting these reductions was a 0.2 MMBoe increase associated with a reduction in expenses and other commercial improvements.

Our Niobrara proved developed reserves are attributed to 48 horizontal producing wells. Reservoir characteristics of the Niobrara in the North Park Basin are similar to those of the Niobrara in the DJ Basin, consisting of multiple stratigraphic benches. In the North Park Basin, production performance and reservoir data gathered from Niobrara producing wells confirm consistency in reservoir properties such as porosity, thickness and stratigraphic conformity.

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

	Year Ended December 31, 2020	Year Ended December 31, 2019
Reserves converted from proved undeveloped to proved developed (MMBoe)	—	3.7
Drilling and infrastructure capital expended to convert proved undeveloped reserves to proved developed reserves (in millions)	$ —	$ 95.3

There were no proved underdeveloped reserves at December 31, 2020, which was a decrease of 27.8 MMBoe from the prior year. This decrease was primarily due to the Company not having had any plans to drill any new wells in the then current commodity price environment.

Total estimated proved undeveloped reserves was 27.8 MMBoe at December 31, 2019, which was a decrease of 40.1 MMBoe from the prior year. This decrease was primarily due to 39.7 MMBoe associated with removing PUDs due to the decrease in year-end SEC commodity pricing consisting of 17.8 MMBoe of Mid-Continent PUD reserves and 21.9 MMBoe of North Park Basin PUD reserves.

For additional information regarding changes in proved reserves during each of the two years ended December 31, 2020 and 2019 see “Note 21—Supplemental Information on Oil and Natural Gas Producing Activities” to the accompanying consolidated financial statements in Item 8 of this report.

Significant Area

Oil, natural gas and NGL production for fields containing more than 15% of our total proved reserves at each year end are presented in the table below. The Mid-Continent area contained more than 15% of total proved reserves for both years ended December 31, 2020 and 2019.

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Year Ended December 31, 2020				
Mid-Continent	1,144	2,694	23,552	7,764
Year Ended December 31, 2019				
Mid-Continent	1,988	2,908	33,164	10,423

Mid-Continent. The mid-continent interest are largely aggregated across the Mississippian Lime, Meramec and Osage formations. Our interests in the Mid-Continent area as of December 31, 2020 included 1,394 gross (789.0 net) producing wells and a 57% average working interest in the producing area.

Production and Price History

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

	Year Ended December 31,	
	2020	2019
Production data (in thousands)		
Oil (MBbls)	2,084	3,519
NGL (MBbls)	2,694	2,910
Natural gas (MMcf)	23,552	33,164
Total volumes (MBoe)	8,703	11,956
Average daily total volumes (MBoe/d)	23.8	32.8
Average prices—as reported (1)		
Oil (per Bbl)	$ 35.33	$ 52.96
NGL (per Bbl)	$ 6.67	$ 12.23
Natural gas (per Mcf)	$ 0.97	$ 1.33
Total (per Boe)	$ 13.15	$ 22.26
Expenses per Boe		
Production costs (2)	$ 4.99	$ 7.60

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

Productive Wells

The following table presents the number of productive wells in which we owned a working interest at December 31, 2020. We operate substantially all of our wells. Productive wells consist of producing wells and wells capable of producing, including oil wells awaiting connection to production facilities and natural gas wells awaiting pipeline connections to commence deliveries. Gross wells are the total number of producing wells in which we have a working interest and net wells are the sum of the fractional working interests owned in gross wells. Prior to February 5, 2021, we held assets in the North Park Basin, which have been sold in their entirety.

	Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Area						
Mid-Continent	1,060	591	334	198	1,394	789
North Park Basin	48	48	—	—	48	48
Total	1,108	639	334	198	1,442	837

Drilling Activity

The following table presents information with respect to wells completed during the periods indicated. This information is not necessarily indicative of future performance, and should not be interpreted to present any correlation between the number of productive wells drilled and quantities or economic value of reserves found. Productive wells are those that produce commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return. During the year ended December 31, 2020, there were no wells drilled or completed.

	2019	
	Gross	Net
Completed Wells		
Development		
Productive	28	20.6
Dry	—	—
Total	28	20.6
Exploratory		
Productive	—	—
Dry	—	—
Total	—	—
Total		
Productive	28	20.6
Dry	—	—
Total	28	20.6

We had no third-party rigs operating on our Mid-Continent or North Park Basin acreage at December 31, 2020 or any wells awaiting completion.

Developed and Undeveloped Acreage

The following table presents information regarding our developed and undeveloped acreage at December 31, 2020. Prior to February 5, 2021, we held assets in the North Park Basin, which have been sold in their entirety.

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Area				
Mid-Continent	492,965	346,098	75,097	33,933
North Park Basin	18,676	18,443	78,981	71,223
Total	511,641	364,541	154,078	105,156

Approximately 0.94% of our gross total acreage in the Mid-Continent and 44.55% in North Park Basin is on federal lands.

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

As of December 31, 2020, the gross and net acres subject to leases in the undeveloped acreage above are set to expire as follows:

	Acres Expiring	
	Gross	Net
Twelve Months Ending		
December 31, 2021	4,280	2,638
December 31, 2022	3,181	2,370
December 31, 2023	—	—
December 31, 2024 and later	566	339
Other (1)	146,051	99,809
Total	154,078	105,156

(1) Leases remaining in effect until development efforts or production on the particular lease has ceased.

The acreage due to expire during the twelve months ending December 31, 2021, includes approximately 2,717 gross (1,271 net) acres in the Mid-Continent and 1,564 gross (1,367 net) acres in the North Park Basin. Prior to February 5, 2021, we held assets in the North Park Basin, which have been sold in their entirety.

Marketing and Customers

We sell our oil, natural gas and NGLs to a variety of customers, including utilities, oil and natural gas companies and trading and energy marketing companies. We had three customers that each individually accounted for more than 10% of our total revenue during the 2020 period. See "Note 1—Summary of Significant Accounting Policies" to the accompanying consolidated financial statements in Item 8 of this report for additional information on our major customers. The number of readily available purchasers in the areas where we sell our production makes it unlikely that the loss of a single customer would materially affect our sales. We do not have any material commitments to deliver fixed and determinable quantities of oil and natural gas in the future under existing sales contracts or sales agreements.

Title to Properties

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

COMPETITION

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

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

SEASONAL NATURE OF BUSINESS

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

ENVIRONMENTAL REGULATIONS

General

Our oil and natural gas development operations are subject to stringent and complex federal, state, tribal, regional and local laws and regulations governing, among other factors, worker safety and health, the discharge and disposal of substances into the environment, and the protection of the environment and natural resources. Numerous governmental entities, including the EPA and analogous state and local agencies, (and, under certain laws, private individuals) have the power to enforce compliance with these laws and regulations and any permits issued under them. These laws and regulations may, among other things: (i) require permits to conduct exploration, drilling, water withdrawal, wastewater disposal and other production related activities; (ii) govern the types, quantities and concentrations of substances that may be disposed or released into the environment or injected into formations in connection with drilling or production activities, and the manner of any such disposal, release, or injection; (iii) limit or prohibit construction or drilling activities or require formal mitigation measures in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered or threatened species; (iv) require investigatory and remedial actions to mitigate pollution conditions arising from the Company’s operations or attributable to former operations; (v) impose safety and health restrictions designed to protect employees and others 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. For example, on January 20, 2021, the Biden Administration placed a 60-day moratorium on new oil and gas leasing and drilling permits on federal land, and on January 27, 2021, the Department of Interior acting pursuant to an Executive Order from President Biden suspended the federal oil and gas leasing program indefinitely. These actions could have a material adverse effect on the Company and our industry. Prior to the North Park Basin sale, approximately 7.34% of our gross total acreage was on federal lands and post sale approximately 0.94% of our gross total acreage was on federal lands. Further, we may be unable to pass on increased environmental compliance costs to our customers. Moreover, accidental releases, including spills, may occur in the course of our operations, and there can be no assurance that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property and natural resources or personal injury. While we do not believe that compliance with existing environmental laws and regulations and that continued compliance with existing requirements will have an adverse material effect on us, we can provide no assurance that we will not incur substantial costs in the future related to revised or additional environmental regulations that could have a material adverse effect on our business, financial condition, and results of operations.

The following is a summary of the more significant existing and proposed environmental and occupational safety and health laws and regulations, as amended from time to time, to which our business operations are subject and for which compliance may have a material adverse impact on the Company.

Hazardous Substances and Wastes

We currently own, lease, or operate, and in the past have owned, leased, or operated, properties that have been used in the exploration and production of oil and natural gas. We believe we have utilized operating and disposal practices that were standard in the industry at the applicable time, but hazardous substances, hydrocarbons, and wastes may have been disposed or released on, from or under the properties owned, leased, or operated by us or on or under other locations where these substances and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose storage treatment and disposal or release of hazardous substances, hydrocarbons, and wastes were not under our control. These properties and the substances or wastes disposed or released on them may be subject to the Comprehensive Environmental Response, Compensation, and Liability Act, as amended ("CERCLA"), the federal Resource Conservation and Recovery Act, ("RCRA"), and analogous state laws. Under these laws, we could be required to investigate, monitor, remove or remediate previously disposed substances or wastes (including substances or wastes disposed of or released by prior owners or operators or third parties whose waste was commingled with ours), to investigate and clean up contaminated property, to perform corrective 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 "potentially responsible parties" 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. Although petroleum, natural gas and natural gas liquids are excluded from the definition of "hazardous substance" under CERCLA, despite this so-called "petroleum exclusion," certain products used in the course of our operations may be regulated as CERCLA hazardous substances. To date, no Company-owned or operated site has been designated as a Superfund site, and we have not been identified as a responsible party for any Superfund site.

We also generate wastes that are subject to the requirements of RCRA and comparable state statutes. RCRA imposes strict "cradle-to-grave" requirements on the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Drilling fluids, produced waters and other wastes associated with the exploration, production and/or development of oil and natural gas, including naturally-occurring radioactive material, if properly handled, are currently excluded from regulation as hazardous wastes under RCRA and, instead, are regulated under RCRA's less stringent non-hazardous waste requirements. However, it is possible that these wastes could be classified as hazardous wastes in the future. 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.

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. For example, 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 to be aggregated for permitting purposes, resulting in treatment as a major source, and thereby triggering more stringent air permitting requirements. The need to acquire such permits has the potential to delay or limit the development of our oil and natural gas projects.

Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues. For example, in October 2015, the EPA issued a final rule under the CAA, lowering the National Ambient Air Quality Standards for ground-level ozone to 70 parts per billion under both the primary and secondary standards to provide requisite protection of public health and welfare. The EPA was required to make attainment and non-attainment designations for specific geographic locations under the revised standards by October 1, 2017, but missed the deadline. Subsequently, in November 2017, the EPA published a list of areas that are in compliance with the new ozone standards and separately in December 2017 issued responses to state recommendation for designating non-attainment areas. In November 2018, the EPA issued final rules implementing the non-attainment area designations. While the EPA has determined that all counties in which we operate are in attainment with the new ozone standard, these determinations may be revised in the future. On December 31, 2020, EPA published its decision to retain the 2015 ozone standards; however, the Biden Administration has announced that it intends to review this rule under President Biden's *Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis*. Further reductions in the ozone National Ambient Air Quality Standards could affect our operations and result in the need to install new emissions controls, longer permitting timelines and significant increases in our capital or operating expenditures. Compliance with these and any future 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 of 1972, as amended, also known as the Clean Water Act (the "CWA"), and analogous state laws and implementing regulations, impose restrictions and strict controls regarding the discharge of pollutants into waters of the United States. Pursuant to these laws and regulations, the discharge of pollutants into regulated waters is prohibited unless it is permitted by the EPA, the Army Corps of Engineers ("Corps") or an analogous state or tribal agency. We do not presently discharge pollutants associated with the exploration, development and production of oil and natural gas into federal or state waters. The CWA and analogous state laws and regulations also impose restrictions and controls regarding the discharge of sediment via storm water run-off from a wide variety of construction activities. Such activities are generally prohibited from discharging sediment unless permitted by the EPA or an analogous state agency. The scope of EPA's and the Corps' regulatory authority under Section 404 of the CWA has been the subject of extensive litigation and frequently changing regulations. The EPA issued a final rule in September 2015 that attempted to clarify the federal jurisdictional reach over waters of the United States ("WOTUS") under Section 404 of the CWA. The EPA and the Corps then proposed a rulemaking in June 2017 to repeal the June 2015 WOTUS rule and also announced their intent to issue a new rule redefining the term WOTUS as used in the CWA. The EPA and the Corps issued a final rule in January 2018 staying implementation of the 2015 WOTUS rule for two years. On October 22, 2019, EPA and the Corps published a final rule repealing the 2015 WOTUS rule, and EPA and the Corps promulgated the Navigable Waters Protection Rule on April 21, 2020, which provides a revised definition of WOTUS and became effective on June 22, 2020. These regulations have been challenged in federal court, however, and the scope of the CWA's jurisdiction may remain fluid until all litigation is concluded. Further regulatory changes are likely, as the Biden Administration has announced that it intends to review the Navigable Waters Protection Rule under President Biden's *Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis*. The pending litigation and future regulations concerning the definition of WOTUS may result in an expansion of the scope of the CWA's jurisdiction, and we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas or other WOTUS in connection with our operations. Also, in June 2016, the EPA issued a final rule implementing wastewater pretreatment standards that prohibit onshore unconventional oil and natural gas extraction facilities from sending wastewater to publicly-owned treatment works. This restriction of disposal options for hydraulic fracturing waste and other changes to CWA requirements may result in increased costs.

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

Subsurface Injections

Underground injection operations performed by us are subject to the Safe Drinking Water Act ("SDWA"), as well as analogous state laws and regulations. Under the SDWA, the EPA established the Underground Injection Control ("UIC") program, which established the minimum program requirements for state and local programs regulating underground injection activities. The UIC program includes requirements for permitting, testing, monitoring, record keeping and reporting of injection well activities, as well as a prohibition against the migration of fluid containing any contaminant into underground sources of drinking water. State regulations require a permit from the applicable regulatory agencies to operate underground injection wells. Although the Company monitors the injection process of its wells, any leakage from the subsurface portions of the injection wells could cause degradation of fresh groundwater resources, potentially resulting in suspension of our UIC permit, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource and imposition of liability by third-parties claiming damages for alternative water supplies, property damages and personal injuries. Some states have considered laws mandating flowback and produced water recycling. Other states have undertaken studies, in some cases such as New Mexico in conjunction with the EPA, to assess the feasibility of recycling produced water on a large scale. If such laws are adopted in areas where we conduct operations, our operating costs may increase significantly.

Furthermore, in response to recent seismic events near underground disposal wells used for the disposal by injection of produced water resulting from oil and natural gas activities, federal and some state agencies are investigating whether such wells have caused increased seismic activity, and some states have restricted, suspended or shut down the use of such disposal wells. For example, in Oklahoma, the Oklahoma Corporation Commission (“OCC”) has implemented a variety of measures including adopting the National Academy of Science’s “traffic light system,” pursuant to which the agency reviews new disposal well applications for proximity to faults, seismicity in the area and other factors in determining whether such wells should be permitted, permitted only with special restrictions, or not permitted. The OCC also evaluates existing wells to assess their continued operation, or operation with restrictions, based on location relative to such faults, seismicity and other factors, with certain of such existing wells required to make frequent, or even daily, volume and pressure reports. In addition, the OCC has issued rules requiring operators of certain saltwater disposal wells in the state to, among other things, conduct mechanical integrity testing or make certain demonstrations of such wells’ depth that, depending on the depth, could require the plugging back of such wells and/or the reduction of volumes disposed in such wells. As a result of these measures, the OCC from time to time has developed and implemented plans calling for wells within areas of interest where seismic incidents have occurred to restrict or suspend disposal well operations in an attempt to mitigate the occurrence of such incidents. For example, in February 2016, the OCC issued a plan to reduce disposal well volume in the Arbuckle formation by 40 percent, covering approximately 5,281 square miles and 245 disposal wells injecting wastewater into the Arbuckle formation. In the plan, the OCC identified 76 SandRidge-operated disposals wells, prescribed a four stage volume reduction schedule and set April 30, 2016 as the final date for compliance with the tiered volume reduction plan. In March 2016, the OCC reduced the injection volume of additional Arbuckle disposal wells, including wells we operate. Following earthquakes in August, September and November 2016, the OCC and the EPA further limited the disposal volumes that can be disposed in Arbuckle wells, although these actions did not cover our disposal wells. While induced seismic events generally decreased in 2017, the OCC expanded restrictions on the use of existing Arbuckle disposal wells and imposed new reporting requirements related to disposal volumes on wells injecting produced water into the Arbuckle formation. In February 2018, the OCC instituted a new protocol to further address seismicity in the Sooner Trend Anadarko Basin Canadian and Kingfisher County and South Central Oklahoma Oil Province Plays which requires various actions, such as a pause in operations for several hours, when certain seismic data is observed. These and similar future protocols that may be adopted in response to future seismicity concerns may reduce the productivity of our operations in relevant areas.

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

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

Climate Change

In December 2009, the EPA published its findings that emissions of CO_2, methane and certain other “greenhouse gases” ("GHGs") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. Based on its findings, the EPA has adopted and implemented regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration ("PSD") construction and Title V operating permit requirements for GHG emissions from certain large stationary sources that already are major sources of criteria pollutants under the CAA. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that typically are GHG emissions could adversely affect our operations and restrict or delay our 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.

In June 2016, the EPA finalized rules to reduce methane emissions from new, modified or reconstructed sources in the oil and natural gas sector, including implementation of a leak detection and repair ("LDAR") program to minimize methane emissions, under the CAA's New Source Performance Standards in 40 C.F.R. Part 60, Subpart OOOOa ("Quad Oa"). On April 18, 2017, the EPA announced its intention to reconsider certain aspects of those regulations, and in June 2017, the EPA proposed a two-year stay of certain requirements of the Quad Oa regulations. In October 2018, the EPA proposed revisions to Quad Oa, such as changes to the frequency for monitoring fugitive emissions at well sites and changes to requirements that a professional engineer certify that meeting certain Quad Oa requirements is technically infeasible. The EPA proposed further revisions to Quad Oa on September 24, 2019, including rescinding the methane requirements in Quad Oa that apply to sources in the production and processing segments of the industry. In September 2020, the EPA finalized amendments to Quad Oa that rescind requirements for the transmission and storage segment of the oil and natural gas industry and rescind methane-specific limits that apply to the industry's production and processing segments, among other things. The Biden Administration has announced that it intends to review the September 2020 rules under President Biden's *Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis*, which review may result in the reinstatement of the now-rescinded standards or promulgation of more stringent standards. Regardless of the September 2020 amendments to Quad Oa, it is possible that these rules and future revisions thereto will continue to require oil and gas operators to expend material sums.

In addition, in November 2016, the U.S. Department of the Interior Bureau of Land Management ("BLM") issued final rules to reduce methane emissions from venting, flaring, and leaks during oil and natural gas operations on federal lands that are substantially similar to the EPA Quad Oa requirements. However, in December 2017, the BLM published a final rule to temporarily suspend or delay certain requirements contained in the November 2016 final rule until January 17, 2019, including those requirements relating to venting, flaring and leakage from oil and gas production activities. Further, in September 2018, the BLM published a final rule revising or rescinding certain provisions of the 2016 rule, which became effective on November 27, 2018. Both the 2016 and the 2018 rule were challenged in federal court. On July 21, 2020, a Wyoming federal court vacated almost all of the 2016 rule, including all provisions relating to the loss of gas through venting, flaring, and leaks, and on July 15, 2020, a California federal court vacated the 2018 rule. As a result of these decisions, the 1979 regulations concerning venting, flaring and lost production on federal land have been reinstated. The Biden Administration is likely to impose new regulations on GHG emissions from oil and natural gas production operations on federal land, given the long-term trend towards increasing regulation in this area. Moreover, several states where we operated as of December 31, 2020, including Colorado, have already adopted rules requiring operators of both new and existing sources to develop and implement a LDAR program and to install devices on certain equipment to capture 95 percent of methane emissions. Compliance with these rules could require us to purchase pollution control equipment and optical gas imaging equipment for LDAR inspections, and to hire additional personnel to assist with inspection and reporting requirements.

In addition, a number of state and regional efforts are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. On an international level, the United States is one of almost 200 nations that agreed in December 2015 to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measure each country will use to achieve its GHG emissions targets, (the "Paris Agreement"). However, the Paris Agreement does not impose any binding obligations on the United States. In June 2017, President Trump announced that the United States would withdraw from the Paris Agreement, which became effective November 4, 2020. President Joe Biden announced that the United States will rejoin the Paris Agreement as of January 20, 2021. Further, several states and local governments remain committed to the principles of the Paris Agreement in their effectuation of policy and regulations. It is not possible at this time to predict how or when the United States might impose restrictions on GHGs as a result of the Paris Agreement. The adoption and implementation of any laws or regulations imposing reporting obligations on, or limiting emissions of GHG from, our equipment and operations could require additional expenditures to reduce emissions of GHGs associated with its operations or could adversely affect demand for the oil and natural gas we produce, and thus possibly have a material adverse effect on our revenues, as well as having the potential effect of lowering the value of our reserves.

Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities or increase the costs of such funding. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and gas will continue to represent a substantial percentage of global energy use over that time.

Finally, to the extent increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events, such events could have a material adverse effect on the Company and potentially subject the Company to further regulation.

Endangered or Threatened Species

The federal Endangered Species Act (the "ESA") restricts activities that may affect endangered or threatened species or their habitats without first obtaining an incidental take permit and implementing mitigation measures. Similar protections are offered to migratory birds under the federal Migratory Bird Treaty Act and to bald and golden eagles under the Bald and Golden Eagle Protection Act. While compliance with the ESA has not had an adverse effect on our exploration, development and production operations in areas where threatened or endangered species or their habitat are known to exist, it may require us to incur increased costs to implement mitigation or protective measures and also may delay, restrict or preclude drilling activities in those areas or during certain seasons, such as breeding and nesting seasons. In addition, certain of our federal and state leases may contain stipulations that require us to take measures to safeguard certain species, including the sage grouse, and their habitats known to be located within the area of the lease. Although the U.S. Fish and Wildlife Service ("USFWS") declined to list the sage grouse under the ESA in 2015 and subsequently developed a conservation plan to protect existing habitat, some environmental groups have continued to raise concerns about sufficient protections for the sage grouse population. Under the plan, the USFWS committed to review the status of the species every five years to evaluate conservation actions, although USFWS has not yet completed the five-year review that was due to be completed in 2020. In addition, the U.S. Department of Interior ("DOI") proposed in December 2018 revisions to the existing sage grouse conservation plan that, amongst other things, was intended to give the DOI and individual states flexibility to allow for increased activity in grouse habitat management areas encompassing parts of Colorado, Idaho, Nevada, Northern California, Oregon, Utah and Wyoming. Several conservation groups challenged the rules, and on October 16, 2019, the U.S. District Court for the District of Idaho issued a preliminary injunction blocking implementation of the new rules in Idaho, Wyoming, Colorado, Utah, Nevada, Oregon, and part of California. In January 2021, the DOI issued Records of Decision for six Supplemental Environmental Impact Statements for management of sage grouse habitat on public lands in seven states to address the court's decision; however, the Biden Administration has announced that it intends to review these acts under President Biden's *Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis*. It is also possible that this review could result in the sage grouse being re-listed under the ESA in the future. 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.

Further, in February 2016, the USFWS published a final policy which alters how it identifies critical habitats for endangered and threatened species. In August 2019, the USFWS issued three final rules revising its ESA regulations, consisting of changes to the procedures and criteria for listing or delisting species and designating critical habitat, removal of the automatic take prohibition for species listed as threatened, and regulations for protection of threatened species, and new procedures and time frames for required consultations by other federal agencies. The USFWS also issued a final rule in December 2020 defining the term "habitat" for purposes of making critical habitat designations under the ESA. In general, these rules were designed to alleviate some of the burdens of the ESA and streamline its implementation, but the prospect of new species listings and critical habitat designations remains. The Biden Administration has announced that it intends to review these rules under President Biden's *Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis*.

The designation of previously unprotected species as threatened or endangered in areas where we operate could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce our reserves. 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.

Employee Health and Safety

Our operations are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act ("OSHA"), and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA Hazard Communication Standard requires us to maintain information concerning hazardous materials used or produced in our operations and to provide this information to employees and various entities. 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 must submit information regarding those chemicals by March 1 of each year to state and local authorities in order to facilitate emergency planning and response. That information is generally available to employees, state and local governmental authorities, and the public. We do not believe that compliance with applicable laws and regulations relating to worker health and safety will have a material adverse effect on our business and results of operations.

State and Other Regulation

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

Hydraulic Fracturing

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

Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process but, at this time, federal legislation related to hydraulic fracturing appears uncertain. At the state level, some states, including Oklahoma, Kansas and Colorado, have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, disclosure, operational or well construction requirements on hydraulic fracturing activities, or that prohibit hydraulic fracturing altogether. Local governments may also seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new laws or regulations that significantly restrict hydraulic fracturing are adopted at the local, state or federal level, 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 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 material environmental concerns.

OTHER REGULATION OF THE OIL AND NATURAL GAS INDUSTRY

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

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

Drilling and Production

Our operations are subject to various types of regulation at federal, state, local and Native American tribal levels that 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 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 and Oklahoma impose financial assurance requirements on operators. The Corps and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration.

Natural Gas Sales and Transportation

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

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

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

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

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

Oil and NGL Sales and Transportation Rates

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

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

EMPLOYEES

As of March 1, 2021, we had 103 full-time employees, including 87 field employees and 16 corporate employees. As of December 31, 2020, we had 114 full-time employees, including 98 field employees and 16 corporate employees. At December 31, 2019, we had 270 full-time employees, including 140 field employees and 130 corporate employees.

Health, Safety and Environment

Our people are a key driver to our success in Health, Safety and Environment ("HSE"). Our HSE policy includes a commitment to provide safe and healthy working conditions for the prevention of work-related injury and ill health and is appropriate for the purpose, size and context of the organization. As part of our HSE policy, we aim to identify and correct any work practices that pose an HSE risk to our employees. The Company is devoted to creating a sustainable environment and implementing process improvements for both health and safety and the environment. We evaluate our processes to ensure our protection schemes and work practices minimize these risks. Furthermore, we periodically evaluate our HSE objectives to ensure they remain aligned with our HSE goals and annually create a strategy focused on risk reduction to get us closer to zero incidents.

During 2020, our experience and continuing focus on workplace safety have enabled us to preserve business continuity without sacrificing our commitment to keeping our colleagues and workplace visitors safe during the COVID-19 pandemic.

Item 1A. *Risk Factors*

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

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

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

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

- changes in regional, domestic and foreign supply of, and demand for, oil, natural gas and NGLs, as well as perceptions of supply of, and demand for, oil, natural gas and NGLs generally;
- the price and quantity of foreign imports;
- the amount of exports from 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;
- the price and availability of alternative fuels; and
- the strength or weakness of the U.S. dollar to other currencies.

These factors and the volatility of the energy markets, which we expect will continue, make it extremely difficult to predict future oil, natural gas and NGL price movements with any certainty. For oil, from January 2016 through December 2020, the NYMEX settled price fluctuated between a high of $77.41 per Bbl and a low of $(36.98) per Bbl. For natural gas, from January 2016 through December 2020, the month-end NYMEX settled price fluctuated between a high of $4.84 per MMBtu and a low of $1.48 per MMBtu. In addition, the market price of natural gas is generally higher in the winter months than during other months of the year due to increased demand for natural gas for heating purposes during the winter season. For NGLs, prices exhibited similar volatility from January 2016 through December 2020.

A buildup in inventories, lower sustained global demand, or other unexpected factors could cause prices for U.S. oil, natural gas and NGLs to further weaken, which could negatively affect our cash flows and results of operations. For instance, crude oil prices have experienced downward pressure during the year ended 2020 as a result of decreasing demand from the growing impact of the coronavirus pandemic, among other factors. Under such conditions, revenues may be negatively affected, and the amount of oil, natural gas and NGLs we can produce economically may be reduced, causing us to make substantial downward adjustments to our estimated proved reserves and having a material adverse effect on our financial condition and results of operations.

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

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

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

Certain of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, environmental contamination or loss of wells and regulatory fines or penalties.

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

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

Future drilling activities face substantial uncertainties.

Our ability to drill and develop wells on our existing acreage depends on a number of uncertainties, including oil and natural gas and NGL prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering and midstream system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors. Because of these uncertain factors, we do not know if certain locations will ever drilled or if we will be able to produce natural gas or oil from any of our potential locations.

Our acreage must be drilled before lease expiration, generally within three to five years of the original date of the lease, 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 or economically desirable, 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 develop such acreage.

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

The oil and natural gas industry is capital intensive. Our future oil, natural gas and NGL reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current estimated proved reserves and finding or acquiring additional economically recoverable reserves. We make substantial capital expenditures in our business and operations for the acquisition, development and production of oil, natural gas and NGL reserves. Historically, we have financed capital expenditures primarily with cash generated by operations, borrowings on our New Credit Facility as well as our Prior Credit Facility and proceeds from asset sales. In particular, cash flow from operations was $36.2 million and $121.3 million for the years ended December 31, 2020 and 2019, respectively.

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 are not accessible or if our ability to draw on our New Credit Facility is compromised, we may be unable to implement our 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.

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, access to capital and results of operations.

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

Future price declines may result in reductions of the asset carrying values of our oil and natural gas properties.

We utilize the full cost method of accounting for costs related to our oil and natural gas properties. Under this accounting method, all costs for both productive and nonproductive properties are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the unit-of-production method. However, the amount of these costs that can be carried as capitalized assets is subject to a ceiling, which limits such pooled costs to the aggregate of the present value of future net revenues of proved oil, natural gas and NGL reserves attributable to proved properties, discounted at 10%, plus the cost of unproved properties. The full cost ceiling is evaluated at the end of each quarter using the SEC prices, adjusted for the impact of derivatives accounted for as cash flow hedges, if any. The Company incurred full cost ceiling impairment charges of $218.4 million and $409.6 million for the years ended December 31, 2020 and December 31, 2019, respectively. Cumulative full cost ceiling impairment from the Emergence Date through December 31, 2020 totaled $947.1 million. If oil, natural gas and NGL prices decline further in the near term, and without other mitigating circumstances, we may experience additional losses of future net revenues, including losses attributable to quantities that cannot be economically produced at lower prices, which would likely cause us to record additional write-downs of capitalized costs of 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.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities and present value of our reserves. Our current estimates of reserves could change, potentially in material amounts, in the future.

The process of estimating oil, natural gas and NGL reserves is complex and inherently imprecise, requiring interpretations of available technical data and many assumptions, including assumptions relating to production rates and economic factors such as historic oil and natural gas prices, drilling and operating expenses, capital expenditures, the assumed effect of governmental regulation and availability of funds for development expenditures. Inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves. See “Business—Primary Business Operations” in Item 1 of this report for information about our oil, natural gas and NGL reserves.

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

The ability to attract and retain key personnel is critical to the success of our business and the loss of senior management or technical personnel or our inability to hire additional qualified personnel could adversely affect our operations.

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

We are subject to litigation and adverse outcomes in such litigation could have a material effect on our financial condition.

We are, and from time to time may become, subject to litigation and various legal proceedings, including stockholder derivative suits, class action lawsuits and other matters, that involve claims for substantial amounts of money or for other relief or that might necessitate changes to our business or operations. Additionally, we remain a nominal defendant in certain litigation matters discussed in Item 3. “Legal Proceedings,” for the purposes of fulfilling indemnification obligations for legal expenses, including any settlement amounts, to certain former officers of the Company and the SandRidge Mississippian Trust

I. The defense of these actions has been and may continue to be both time consuming and expensive. We evaluate these litigation claims and legal proceedings to assess the likelihood of unfavorable outcomes and to estimate, if possible, the amount of potential losses. Based on these assessments and estimates, we may establish reserves and/or disclose the relevant litigation claims or legal proceedings, as and when required or appropriate. These assessments and estimates are based on information available to management at the time of such assessment or estimation and involve a significant amount of judgment. As a result, actual outcomes or losses could differ materially from those envisioned by our current assessments and estimates. Our failure to successfully defend or settle any litigation or legal proceedings could result in liability that, to the extent not covered by our insurance, could have a material effect on our business, financial condition and results of operations.

The agreements governing our New Credit Facility have restrictions and financial covenants, which could adversely affect our operations.

The agreements governing our New Credit Facility restrict our ability to, among other things, obtain additional financing, incurrence of liens, indebtedness, asset dispositions, fundamental changes, restricted payments and other customary covenants. The New Credit Facility also requires us to comply with certain financial covenants and ratios. See additional discussion of the New Credit Facility under *"Indebtedness—Credit Facilities."* Persistent depressed oil or natural gas prices or further declines in such prices, without other mitigating circumstances, could prevent us from complying with the financial covenants under the New Credit Facility. Our failure to comply with any of the restrictions and covenants under the New 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.

We may not have the financial resources in the future to make any mandatory principal prepayments under the New 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 New Credit Facility is incurred. If any future indebtedness under our New Credit Facility were to be accelerated, our assets may not be sufficient to repay such indebtedness in full.

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

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

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

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

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

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

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

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

The cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive or may suffer from declining production faster than anticipated. The use of seismic data and other technologies and the study of producing fields in the same area do not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. During 2020, we did not drill any wells.

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 may experience drought conditions from time to time. 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 access to capital and other 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 New Credit Facility. Adverse credit and capital market conditions may require us to reduce the carrying value of assets associated with any 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.

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, 2020, approximately 90.5% of our proved reserves and approximately 89.2% of our annual production was located in the Mid-Continent. We divested all of our North Park Basin assets in February 2021, making substantially all of our future proved reserves and production located in the Mid-Continent. This concentration could disproportionately expose us to operational and regulatory risk in this area. This relative lack of diversification in location of our key operations could expose us to adverse developments in the Mid-Continent or the oil and natural gas markets, including, for example, transportation or treatment capacity constraints, curtailment of production due to weather, electrical outages, treatment plant closures for scheduled maintenance, changes in the regulatory environment or other factors. These factors could have a significantly greater impact on our financial condition, results of operations and cash flows than if our properties were more diversified.

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

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

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

Shortages or increases in costs of equipment, services and qualified personnel could adversely affect our ability to execute our 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 development plans as projected.

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

The oil and natural gas industry is intensely competitive, and we compete with many companies that have greater financial and other resources than we do. Many of these companies not only explore for and produce oil and natural gas, but also conduct refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or identify, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration and development 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 economic results of drilling operations.

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

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

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

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

Laws and regulations governing oil and natural gas operations 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.

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.

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

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

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

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

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

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

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

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and additives under pressure into targeted subsurface formations to stimulate oil and natural gas production. We routinely have utilized hydraulic fracturing techniques in the majority of our drilling and completion programs. The process is typically regulated by state oil and gas commissions, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA published permitting guidance in February 2014 addressing the use of diesel fuel in fracturing operations; issued CAA final regulations in 2012 and additional CAA regulations in June 2016 governing performance standards for the oil and natural gas industry; and in June 2016 issued final effluent limitations guidelines under the CWA that waste-water from shale natural gas extraction operations must meet before discharging to a publicly-owned treatment plant. The EPA also issued an Advance Notice of Proposed Rulemaking under TSCA in 2014 regarding reporting of the chemical substances and mixtures used in hydraulic fracturing, but, to date, has taken no further action. Separately, the BLM published a final rule in March 2015 that establishes 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, and after various appeals and a presidential executive order directing it to review rules related to the energy industry, the BLM published a final rule rescinding the 2015 rule in December 2017.

From time to time, the U.S. Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process but, at this time, federal legislation related to hydraulic fracturing appears uncertain. 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 Item 1 of this report for additional discussion of the current and potential impacts of legislation or regulatory initiatives related to seismic activity on our operations.

Climate change laws and regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

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

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

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

In addition, there are a number of state and regional efforts that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. On an international level, the United States was one of almost 200 nations that agreed in December 2015 to the Paris Agreement. However, the Paris Agreement did not impose any binding obligations on the United States. In June 2017, President Trump announced that the United States would withdraw from the Paris Agreement, which became effective November 4, 2020. On January 20, 2021, President Joe Biden rejoined the Paris Agreement.

The adoption and implementation of any laws or regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and our operations could require us to incur additional costs to monitor, report and potentially reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas that we produce, and thus possibly have a material adverse effect on our revenues, as well as having the potential effect of lowering the value of our reserves. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for development and production activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and gas will continue to represent a substantial percentage of global energy use over that time. Finally, to the extent increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that could have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events, such events could have a material adverse effect on our assets and operations, and potentially subject us to greater regulation.

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, 2020, as further described in Part II "Item 9A—Controls and Procedures" and "Management's Report on Internal Control over Financial Reporting." Our efforts to develop and maintain our internal controls and to remediate any material weaknesses in our controls may not be successful, and we may be unable to maintain adequate controls over our financial processes and reporting in the future, including future compliance with the obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to develop or maintain effective controls, or difficulties encountered in their implementation, including those related to acquired businesses, or other effective improvement of our internal controls could harm our operating results. Ineffective internal controls could also cause investors to lose confidence in our reported financial information.

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

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

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

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

The full impact of the Dodd-Frank Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter and reduce our ability to monetize or restructure derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations. In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations. At this time, the impact of such regulations is not clear.

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

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

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

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

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 attacks. 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.

Risks Relating to COVID-19

The COVID-19 pandemic has adversely affected our business, and the ultimate effect on our operations and financial condition will depend on future developments, which are highly uncertain and cannot be predicted.

The COVID-19 pandemic has adversely affected the global economy, disrupted global supply chains and created significant volatility in the financial markets. In addition, the pandemic has resulted in travel restrictions, business closures and the institution of quarantining and other restrictions on movement in many communities. As a result, there has been a significant reduction in demand for and prices of crude oil, natural gas and NGL. If the reduced demand for and prices of crude oil, natural gas and NGL continue for a prolonged period, our operations, financial condition, cash flows, level of expenditures and the quantity of estimated proved reserves that may be attributed to our properties may be materially and adversely affected. Our operations also may be adversely affected if significant portions of our workforce are unable to work effectively, including because of illness, quarantines, government actions, or other restrictions in connection with the pandemic. We have implemented workplace restrictions, including guidance for our employees to work remotely if necessary, in our offices and work sites for health and safety reasons and are continuing to monitor national, state and local government directives where we have operations and/or offices. The extent to which the COVID-19 pandemic adversely affects our business, results of operations, and financial condition will depend on future developments, which are highly uncertain and cannot be predicted, including the scope and duration of the pandemic and actions taken by governmental authorities and other third parties in response to the pandemic.

Risks Relating to our Net Operating Loss Carryforwards ("NOLs")

Our ability to use our NOLs may be limited. We have adopted a Tax Benefits Preservation Plan that is designed to protect our NOLs but there is no assurance it will prevent an ownership change resulting in loss of the Company's NOLs.

As of December 31, 2020, we had U.S. federal NOLs of $1.4 billion, net of NOLs expected to expire unused due to the 2016 IRC Section 382 limitation, the majority of which will expire between 2025 and 2037, if not limited by additional triggering events prior to such time. Under the provisions of the Internal Revenue Code of 1986, as amended ("IRC"), changes in our ownership, in certain circumstances, will limit the amount of U.S. federal NOLs that can be utilized annually in the future to offset taxable income. In particular, Section 382 of the IRC imposes limitations on a company's ability to use NOLs upon certain changes in such ownership. Generally, an "ownership change" occurs if the percentage of the Company's stock owned by one or more of its "five-percent shareholders" (as such term is defined in Section 382 of the IRC) increases by more than 50 percentage points over the lowest percentage of stock owned by such stockholder or stockholders at any time over a three-year period. Calculations pursuant to Section 382 of the IRC can be very complicated and no assurance can be given that upon further analysis, our ability to take advantage of our NOLs may be limited to a greater extent than we currently anticipate. We may experience ownership changes in the future as a result of subsequent shifts in our stock ownership that we cannot predict or control that could result in further limitations being placed on our ability to utilize our federal NOLs. If we are limited in our ability to use our NOLs in future years in which we have taxable income, we will pay more taxes than if we were able to utilize our NOLs fully.

On July 1, 2020, our Board of Directors approved, and the Company adopted, a Tax Benefits Preservation Plan in order to protect shareholder value against a possible limitation on the Company's ability to use its tax NOLs and certain other tax benefits to reduce potential future U.S. federal income tax obligations. The Tax Benefits Preservation Plan is designed to reduce the likelihood of an "ownership change" in order to protect our NOLs by deterring any person or group from acquiring beneficial ownership of 4.9% or more of the Company's securities. However, there is no assurance that the Tax Benefits Preservation Plan will prevent all transfers that could result in such an "ownership change."

Risks Relating to our Common Stock

The exercise of all or any number of outstanding Warrants or the issuance of stock-based awards may dilute your holding of shares of our common stock.

As of the date of filing this report, we have outstanding Warrants to purchase approximately 6.7 million shares of our common stock at average exercise prices of either $41.34 and $42.03 per share. In addition, we have as of the date of this report, 1.0 million shares of common stock reserved for future issuance under the SandRidge Energy, Inc. 2016 Omnibus Incentive Plan (the, “Omnibus Incentive Plan”). The exercise of equity awards, including any stock options that we may grant in the future, the Warrants, and the sale of shares of our common stock underlying any such options or the Warrants, could have an adverse effect on the market for our common stock, including the price that an investor could obtain for their shares. Investors may experience dilution in the net tangible book value of their investment upon the exercise of the Warrants and any stock options that may be granted or issued pursuant to the Omnibus Incentive Plan in the future.

We have adopted a Tax Benefits Preservation Plan, which may discourage a corporate takeover.

On July 1, 2020, our Board of Directors adopted a Tax Benefits Preservation Plan and declared a dividend distribution of one right for each outstanding share of our common stock to stockholders of record at the close of business on July 13, 2020. Each share of our common stock issued thereafter will also include one right. Each right entitles its holder, under certain circumstances, to purchase from us one one-thousandth of a share of our Series A Junior Participating Preferred Stock at an exercise price of $5.00 per right, subject to adjustment.

The Board adopted the Tax Benefits Preservation Plan in an effort to protect stockholder value by attempting to protect against a possible limitation on our ability to use our NOLs. We may utilize these NOLs in certain circumstances to offset future United States taxable income and reduce our United States federal income tax liability. Because the Tax Benefits Preservation Plan could make it more expensive for a person to acquire a controlling interest in us, it could have the effect of delaying or preventing a change in control even if a change in control was in our stockholders’ interest.

Anti-takeover provisions in our charter documents and under Delaware corporate law may make it more difficult to acquire us, even though such acquisitions may be beneficial to our stockholders.

In addition to our Tax Benefits Preservation Plan, provisions of our certificate of incorporation and bylaws, as well as provisions of Delaware corporate law, could make it more difficult for a third party to acquire us, even though such acquisitions may be beneficial to our stockholders. These anti-takeover provisions include:

- lack of a provision for cumulative voting in the election of directors;
- the ability of our Board to authorize the issuance of “blank check” preferred stock to increase the number of outstanding shares and thwart a takeover attempt;
- advance notice requirements for nominations for election to the Board of Directors or for proposing matters that can be acted upon by stockholders at stockholder meetings; and
- limitations on who may call a special meeting of stockholders.

The provisions described above, our Tax Benefits Preservation Plan and provisions of Delaware corporate law relating to business combinations with interested stockholders may discourage, delay or prevent a third party from acquiring us. These provisions may also discourage, delay or prevent a third party from acquiring a large portion of our securities, or initiating a tender offer, even if our stockholders might receive a premium for their shares in the acquisition over the then current market price.

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

None.

Item 2. ***Properties***

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

Item 3. ***Legal Proceedings***

See "Note 13—Commitments and Contingencies" to the accompanying consolidated financial statements in Item 8 of this report.

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*

Since October 4, 2016, the Successor Company's common stock has been listed on the New York Stock Exchange ("NYSE") under the symbol "SD."

On February 25, 2021, there were 343 record holders of the Company's common stock, which does not reflect persons or entities that hold the common stock in nominee or "street" name through various brokerage firms and financial institutions.

Issuer Purchases of Equity Securities

None.

Item 6. *Selected Financial Data*

Not Applicable.

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 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

We are an independent oil and natural gas company with a principal focus on acquisition, development and production activities in the U.S. Mid-Continent and North Park Basin of Colorado. Prior to February 5, 2021, we held assets in the North Park Basin, which have been sold in their entirety.

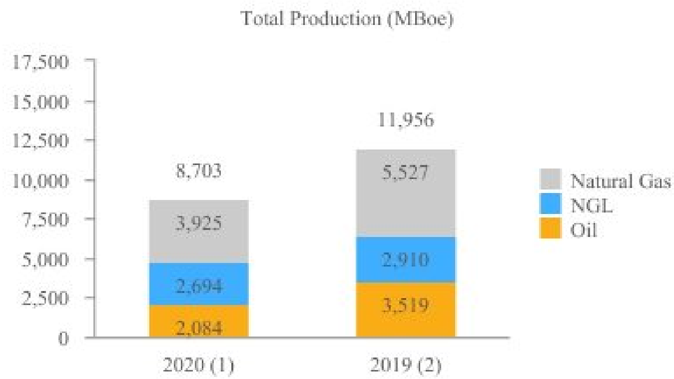
Operational Activities

There was no drilling activity during the year ended December 31, 2020. Operational activities for the year ended December 31, 2019 included the following:

	Year Ended December 31,		
	2019		
	Gross Wells Drilled	Net Wells Drilled	Average Rigs Drilling
Area			
Mid-Continent (1)	11	3.9	0.6
North Park Basin	10	10.0	0.4
Total	21	13.9	1.0

(1) Eight wells were drilled under our previous drilling participation agreement during the year ended December 31, 2019. Under this agreement, we receive a 20% net working interest after funding 10% of the drilling and completion costs related to the subject wells. The last well under this agreement was completed in the second quarter of 2019.

The chart below shows production by product for the years ended December 31, 2020 and 2019:



(1) For the year ended December 31, 2020, Mid-Continent production was 3,925 MBoe in natural gas, 2,694 MBoe in NGLs and 1,144 MBoe in oil totaling 7,763 MBoe. North Park Basin had 940 MBoe in oil.

(2) For the year ended December 31, 2019, Mid-Continent production was 5,527 MBoe in natural gas, 2,908 MBoe in NGLs and 1,988 MBoe in oil totaling 10,423 MBoe. North Park Basin had 1,531 MBoe in oil and 2 MBoe in NGLs totaling 1,533 MBoe.

Total production for 2020 was comprised of approximately 23.9% oil, 45.1% natural gas and 31.0% NGLs compared to 29.4% oil, 46.2% natural gas and 24.4% NGLs in 2019.

Recent Events

- On March 3, 2021, the Company named Mr. Grayson Pranin, formerly its Vice President for Reserves and Engineering, as Senior Vice President and Chief Operating Officer. The Company also named Mr. Salah Gamoudi, the Company's Chief Financial Officer and Chief Accounting Officer, as a Senior Vice President. It also named Mr. Dean Parrish, formerly its Director of Operations, as its Vice President of Operations.

- On February 5, 2021, we sold all of our oil and natural gas properties and related assets of the North Park Basin in Colorado for a purchase price of $47 million in cash. The sale closed for net proceeds of $39.7 million in cash, which is net of effective to closing date adjustments.

- SandRidge Mississippian Trust I: We are party to the Amended and Restated Trust Agreement of SandRidge Mississippian Trust I (the "SDT Trust"), dated April 12, 2011, by and among the Company, the Bank of New York Mellon Trust Company, N.A., and the Corporation Trust Company (the "Trust Agreement"). Pursuant to the Trust Agreement, we have a right of first refusal with respect to any sale of assets of the SDT Trust to a third party following the occurrence of certain events (a "Triggering Event"). On October 23, 2020, the SDT Trust announced the Trust will be required to dissolve and commence winding up beginning as of the close of business on November 13, 2020. At December 31, 2020, the market capitalization of the SDT Trust was $5.1 million of which we own approximately 26.9%.

- On September 10, 2020, the Company closed on the acquisition of the overriding royalty interests of SandRidge Mississippian Trust II for a gross purchase price of $5.25 million (net purchase price of $3.28 million, given the Company's 37.6% ownership of the Trust).

- On August 31, 2020, SandRidge Realty, LLC, a wholly owned subsidiary of the Company, closed on the sale of the Company's 30-story office tower and annex with parking and ancillary uses located at 123 Robert S. Kerr, Oklahoma City, Oklahoma 73102, for net proceeds of approximately $35.4 million.

- On July 1, 2020, the Board declared a dividend distribution of one right (a "Right") for each outstanding share of Company common stock, par value $0.001 per share to stockholders of record at the close of business on July 13, 2020. Each Right entitles its holder, under certain circumstances, to purchase from the Company one one-thousandth of a share of Series A Junior Participating Preferred Stock of the Company, par value $0.001 per share, at an exercise price of $5.00 per Right, subject to adjustment. The description and terms of the Rights are set forth in the tax benefits preservation plan, dated as of July 1, 2020, between the Company and American Stock Transfer & Trust Company, LLC, as rights agent (and any successor rights agent, the "Rights Agent").

Outlook

As discussed in "Business— Our Business Strategy" in Item 1 of this report, we will focus on maximizing free cash flow in 2021 through a combination of cost control measures and the continued exercise of financial discipline and prudent capital allocation, which includes limiting our drilling capital to locations we believe will provide high rates of return in the current commodity price environment. As a result, our planned capital expenditures for 2021 will be similar to our 2020 levels. Given this expected level of capital expenditures, our oil, natural gas and NGL production will likely decline in 2021. We will be prepared to expand our capital program after considering all factors including commodity prices. We will also continue our pursuit of acquisitions and business combinations which provide high margin properties with attractive returns at current commodity prices.

The COVID-19 pandemic and other pricing volatility caused by the announcement of production increases by Saudi Arabia-led OPEC and Russia caused a steep decline in oil prices in March 2020, which further decreased to historic lows in April 2020. Although we cannot reasonably estimate what the full impact of the COVID-19 pandemic and other market volatility will have on our business, it could have a material, adverse impact on near-term future revenues and overall profitability. Additionally, we have implemented several additional initiatives to maximize free cash flow, reduce our debt level, maximize our liquidity position and, ultimately realize greater shareholder value. These initiatives included personnel and non-personnel cost reductions, the sale of the company headquarters during 2020. Prior to February 5, 2021, we held assets in the North Park Basin, which have been sold in their entirety.

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, and our ability to find and economically develop and produce our reserves. 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,	
	2020	2019
Oil (per Bbl)	$ 39.19	$ 57.04
Natural gas (per Mcf)	$ 2.13	$ 2.53

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 to support our operations. During periods where the strike prices for our commodity derivative contracts are below market prices at the time of settlement, we may not fully benefit from increases in the market price of oil and natural gas. Conversely, during periods of declining market prices of oil and natural gas, our commodity derivative contracts may partially offset declining revenues and cash flow to the extent strike prices for our contracts are above market prices at the time of settlement. However, as of December 31, 2020, the Company had no remaining open commodity derivative contracts.

Acquisitions and Divestitures of Properties

2020 Acquisitions and Divestitures

On September 10, 2020, the Company acquired all of the overriding royalty interests held by SandRidge Mississippian Royalty Trust II ("the Trust") for a net purchase price of $3.28 million, given our 37.6% ownership of the Trust. The Company accounted for this transaction as an asset acquisition and allocated the purchase price of the acquisition plus the transactions costs to oil and gas properties.

On August 31, 2020, the Company closed on the previously announced sale of its corporate headquarters building located in Oklahoma City, OK, for net proceeds of approximately $35.4 million.

See "Note 22—Subsequent Event” to the accompanying consolidated financial statements in Item 8 of this report. for information related to the February 5, 2021 sale of our North Park Basin assets.

2019 Acquisitions and Divestitures

Nonmonetary transaction. During the three-month period ended September 30, 2019, the Company transferred its interest in certain proved oil and natural gas properties located in Comanche, Harper and Sumner counties in Kansas along with associated electrical infrastructure and an insignificant amount of accounts receivable with an aggregate estimated fair value of $5.4 million, for an interest in certain other proved oil and natural gas properties located in Comanche, Harper and Barber counties in Kansas. The fair value of the non-oil and gas assets given in the transaction approximated their carrying value, therefore no gain or loss was recognized on the transfer.

Oil, Natural Gas and NGL Production and Pricing

The table below presents production and pricing information for the years ended December 31, 2020, and 2019.

	Year Ended December 31,	
	2020	**2019**
Production data (in thousands)		
Oil (MBbls)	2,084	3,519
NGL (MBbls)	2,694	2,910
Natural gas (MMcf)	23,552	33,164
Total volumes (MBoe)	8,703	11,956
Average daily total volumes (MBoe/d)	23.8	32.8
Average prices—as reported (1)		
Oil (per Bbl)	$ 35.33	$ 52.96
NGL (per Bbl)	$ 6.67	$ 12.23
Natural gas (per Mcf)	$ 0.97	$ 1.33
Total (per Boe)	$ 13.15	$ 22.26
Average prices—including impact of derivative contract settlements (2)		
Oil (per Bbl)	$ 40.10	$ 53.30
NGL (per Bbl)	$ 6.67	$ 12.23
Natural gas (per Mcf)	$ 0.80	$ 1.48
Total (per Boe)	$ 13.83	$ 22.78

(1) Prices represent actual average prices for the periods presented and do not include the impact of derivative transactions.
(2) Excludes early settlements of commodity derivative contracts prior to their contractual maturity.

The table below presents production by area of operation for the years ended December 31, 2020 and 2019, and illustrates the impact of (i) natural declines in existing producing wells in the Mid-Continent, (ii) No new wells in 2020.

	Year Ended December 31,			
	2020		2019	
	Production (MBoe)	% of Total Production	Production (MBoe)	% of Total Production
Mid-Continent	7,763	89.2 %	10,423	87.2 %
North Park Basin	940	10.8 %	1,533	12.8 %
Total	8,703	100.0 %	11,956	100.0 %

Revenues

Consolidated revenues for the years ended December 31, 2020 and 2019 are presented in the table below (in thousands).

	Year Ended December 31,	
	2020	2019
Revenues		
Oil	$ 73,621	$ 186,360
NGL	17,962	35,598
Natural gas	22,867	44,146
Other	526	741
Total revenues	$ 114,976	$ 266,845

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, 2020 and 2019 are shown in the table below (in thousands):

2019 oil, natural gas and NGL revenues	$ 266,104
Change due to production volumes in 2020	(42,779)
Change due to average prices in 2020	(108,875)
2020 oil, natural gas and NGL revenues	$ 114,450

Oil, natural gas and NGL revenues decreased by a combined $151.7 million, or 57.0% for the year ended December 31, 2020, compared to 2019. The average prices for oil, natural gas and NGL's declined significantly during 2020, due largely to an increase in anticipated global supplies of these commodities after a pledged increase in oil production from Saudi Arabia-led OPEC, and the reduction in demand stemming from the COVID-19 pandemic. See “Item 1A. Risk Factors” included in Part I of this Annual Report for additional discussion of the potential impact these events may have on our future revenues.

The decline in production for the year ended December 31, 2020 compared to 2019, largely resulting from the absence of newly drilled wells in 2020 and natural production declines in our existing producing wells in the Mid-Continent and North Park Basin. North Park Basin ("NPB") represented $31.1 million, or 27.0% of the Company's $115.0 million total consolidated Revenues for the year ended December 31, 2020.

Operating Expenses

Operating expenses for the years ended December 31, 2020, and 2019 consisted of the following (in thousands):

	Year Ended December 31, 2020	Year Ended December 31, 2019
Lease operating expenses	$ 43,431	$ 90,938
Production, ad valorem, and other taxes	9,634	19,394
Depreciation and depletion—oil and natural gas	50,349	146,874
Depreciation and amortization—other	7,736	11,684
Total operating expenses	$ 111,150	$ 268,890
Lease operating expenses ($/Boe)	$ 4.99	$ 7.61
Production, ad valorem, and other taxes ($/Boe)	$ 1.11	$ 1.62
Depreciation and amortization—oil and natural gas ($/Boe)	$ 5.11	$ 12.28
Production, ad valorem, and other taxes (% of oil, natural gas, and NGL revenue)	8.4 %	7.3 %

Lease operating expenses for 2020 decreased $47.5 million, or $2.62/Boe from 2019. This decrease primarily resulted from field personnel reductions in force, in addition to the shut-in of wells that had become uneconomic due to natural production declines and deteriorating pricing during the year ended December 31, 2020. NPB represented $9.1 million, or 20.9% of the Company's $43.4 million consolidated Lease operating expense for the year ended December 31, 2020.

Production, ad valorem, and other taxes has decreased primarily due to declining production and revenues. Further, they have increased as a percentage of oil, natural gas, and NGL revenue for the year 2020 compared to 2019, primarily due to ad valorem taxes remaining consistent throughout 2020 while revenues have declined during 2020. NPB represented $1.8 million, or 18.7% of the Company's $9.6 million consolidated Production, ad valorem and other taxes for the year ended December 31, 2020.

Depreciation and depletion for oil and natural gas properties decreased by $96.5 million for the year ended December 31, 2020 compared to 2019 due to an decrease in the average depreciation and depletion rate to $5.11 per Boe in 2020 compared to an average rate of $12.28 in 2019. This rate decrease is primarily due to the full cost ceiling test impairments recorded in the third and fourth quarters of 2019, as well as the ceiling test impairments recorded in 2020.

Impairment

Impairment expense for the years ended December 31, 2020, and 2019 consisted of the following (in thousands):

	Year Ended December 31, 2020	Year Ended December 31, 2019
Impairment		
Full cost pool ceiling limitation	$ 218,399	$ 409,574
Other	38,000	—
Total impairment	$ 256,399	$ 409,574

Full cost pool impairment. Impairment for the year ended December 31, 2020 largely resulted from an impairment charge of $256.4 million, which included a full cost ceiling limitation impairment charge of $218.4 million, and an impairment charge of $38 million to write down the value of the Company's office headquarters to its estimated fair value less estimated costs to sell the building. For the quarter ended December 31, 2020, we recorded a full cost ceiling limitation impairment charge of $2.6 million.

Calculation of the full cost ceiling test is based on, among other factors, trailing twelve-month SEC prices as adjusted for price differentials and other contractual arrangements. The SEC prices utilized in the calculation of proved reserves included in the full cost ceiling test at December 31, 2020 were $39.57 per barrel of oil and $1.99 per Mcf of natural gas, before price differential adjustments.

Based on the SEC prices over the eleven months ended February 1, 2021, as well as the short-term pricing outlook for the remainder of the first quarter 2021, we anticipate the SEC prices utilized in the March 31, 2021 full cost ceiling test may be $39.42 per barrel of oil and $2.16 per Mcf of natural gas, (the "estimated first quarter prices"). Applying these estimated first quarter prices, and holding all other inputs constant to those used in the calculation of our December 31, 2020 ceiling test, no full cost ceiling limitation impairment is indicated for the first quarter of 2021.

However, a full cost ceiling limitation impairment may still be realized in the first quarter of 2021 and in subsequent quarters based on the outcome of numerous other factors such as additional declines in the actual trailing twelve-month SEC prices, lower NGL pricing, changes in estimated future development costs and operating expenses, and other adjustments to our levels of proved reserves. Any such ceiling test impairments in 2021 could be material to our net earnings.

Non-Operating Expenses

Non-operating expenses for the years ended December 31, 2020, and 2019 consisted of the following (in thousands):

	Year Ended December 31,	
	2020	2019
General and administrative	$ 15,327	$ 32,058
Restructuring expenses	2,733	—
Employee termination benefits	8,433	4,792
Gain on derivative contracts	(5,765)	(1,094)
Other operating expense (income)	206	(608)
Total non-operating expenses	$ 20,934	$ 35,148

General and administrative expenses decreased $16.7 million, or 52.2%, for the year ended December 31, 2020 compared to 2019 primarily from a reduction in compensation related costs after completing reductions in force during the second quarter of 2019 and the first three quarters of 2020. Part of the decrease is also due to reductions in professional costs such as legal expenses, technology, software, audit fees and consulting services.

Restructuring expenses represent fees and costs associated with our outsourcing and relocation of certain corporate specific functions that are of a non-recurring nature and expenses related to the 2016 bankruptcy.

Employee termination benefits for the year ended December 31, 2020, include cash and share-based severance costs incurred primarily as a result of the reduction in force. On July 1, 2020, the Company's then current Chief Financial Officer, Michael A. Johnson and Chief Operating Officer, John Suter, separated employment from the Company. As a result, the Company paid cash severance costs and incurred share-based compensation costs associated with these separations during 2020.

Employee termination benefits for the year ended December 31, 2019, include cash and share-based severance costs incurred related to (i) a reduction in force in the second quarter of 2019 and (ii) severance costs associated with the departure of our former Executive Vice President, General Counsel and Corporate Secretary, Phil Warman, and former CEO, Paul McKinney.

See "Note 19—Employee Termination Benefits" to the accompanying consolidated financial statements in Item 8 of this report for additional information.

We recorded a net gain on commodity derivative contracts of $5.8 million and $1.1 million for the years ended December 31, 2020, and 2019, respectively, as reflected in the accompanying consolidated statements of operations, which includes net cash receipts upon settlement of $5.9 million and $6.3 million, respectively.

Our derivative contracts are not designated as accounting hedges and, as a result, changes in the fair value of our commodity derivative contracts are recorded each quarter as a component of operating expenses. Internally, management views the settlement of commodity derivative contracts at contractual maturity as adjustments to the price received for oil and natural gas production to determine "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 commodity derivative contracts, and 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 commodity derivative contracts. See Item 7A. "Quantitative and Qualitative Disclosures about Market Risk" of this report for additional discussion of our commodity derivatives.

Other Income (Expense)

Other income (expense) for the years ended December 31, 2020, and 2019 is reflected in the table below (in thousands):

	Year Ended December 31,	
	2020	2019
Other (expense) income		
Interest expense, net	$ (1,998)	$ (2,974)
Other (expense) income , net	(2,494)	436
Total other (expense) income	$ (4,492)	$ (2,538)

Interest expense for the years ended December 31, 2020, and 2019 consisted of the following (in thousands):

	Year Ended December 31,	
	2020	2019
Interest expense		
Interest expense on debt	$ 2,387	$ 3,658
Interest expense on right of use assets	114	160
Write off of debt issuance costs	266	142
Amortization of debt issuance costs, premium and discounts	—	558
Capitalized interest	(750)	(1,453)
Total	2,017	3,065
Less: interest income	(19)	(91)
Total interest expense, net	$ 1,998	$ 2,974

Interest expense incurred during the year ended December 31, 2020 is primarily comprised of interest and fees paid on the Prior Credit Facility that was terminated on November 30, 2020. Interest expense incurred during the year ended December 31, 2019 is primarily comprised of interest and fees paid on the Prior Credit Facility.

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

The Other (expense) income, net line item for the year ended December 31, 2020 includes an allowance for doubtful accounts of $2.5 million that was recorded as a result of conducting an assessment of governmental and other regulatory receivable balances, which we have deemed as potentially uncollectible. This allowance is non-recurring in nature, and does not represent allowances for doubtful accounts related to joint interest billing receivables or other recurring items.

Liquidity and Capital Resources

At December 31, 2020, our cash and cash equivalents, excluding restricted cash, were $22.1 million. Additionally, we had a $20.0 million term loan outstanding and $10.0 million available under our $30.0 million New Credit Facility, which matures on November 30, 2023. See "Note—11 Long-Term Debt" to the accompanying consolidated financial statements in Item 8 of this report. for further discussion. As of March 1, 2021, the Company had, no outstanding balance under the New Credit Facility revolving line of credit, and a $20.0 million outstanding term loan under the New Credit Facility.

As discussed in "— Recent Events" and "— Outlook" above, we have undertaken several initiatives in 2020, which we believe have the potential to positively impact our liquidity. These initiatives are expected to maximize free cash flow and ultimately realize greater shareholder value to address the negative impact of the COVID-19 pandemic and commodity price volatility on our financial position and future liquidity. These initiatives included personnel and non-personnel cost reductions the sale of our corporate headquarters, and the signing of a purchase and sale agreement to sell our North Park Basin assets.

We are unable to project the full impact the COVID-19 pandemic will have on our financial position and results of operations at this time, but these measures, along with amounts available to be drawn on our New Credit Facility, cash on hand, and other cash flows from operations are expected to provide ample liquidity for the next 12 months.

Working Capital and Sources and Uses of Cash

Our principal sources of liquidity for 2020 included cash flow from operations, cash on hand and amounts available under our New Credit Facility, as discussed in "—Credit Facility" below. As discussed in "— Outlook" above to the accompanying audited consolidated financial statements and "Item 1A. Risk Factors" included in Part I of this Annual Report, we expect the COVID-19 pandemic and other market volatility factors to have a material, adverse impact on future revenue growth and overall profitability for the foreseeable future.

Our working capital deficit decreased to $18.1 million at December 31, 2020, compared to $49.8 million at December 31, 2019, the positive impact on working capital resulted primarily from an increase in cash and cash equivalents at December 31, 2020 as a result of proceeds from asset sales, cash from operations and the new term loan. In addition, accounts payable decreased due to a decline in drilling and completions activity in 2020, in addition to our cost reduction efforts..

We intend to spend between $5 million and $10 million in our 2021 capital budget plan, excluding any expenditures for acquisitions. We intend to fund capital expenditures and other commitments for the next 12 months using cash flows from our operations, borrowings under our New Credit Facility and cash on hand. We will endeavor to keep our capital spending within or very close to our projected cash flows from operations subject to changing industry conditions or events.

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, during the period from January 2016 through December 2020, the NYMEX settled price for oil fluctuated between a high of $77.41 per Bbl and a low of $(36.98) per Bbl, and the month-end NYMEX settled price for gas fluctuated between a high of $4.84 per MMBtu and a low of $1.48 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 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 years ended December 31, 2020, and 2019 are presented in the following table and discussed below (in thousands):

	Year Ended December 31,	
	2020	**2019**
Cash flows provided by operating activities	$ 36,162	$ 121,324
Cash flows provided by (used in) investing activities	25,093	(189,849)
Cash flows (used in) provided by financing activities	(38,957)	54,848
Net increase (decrease) in cash and cash equivalents	$ 22,298	$ (13,677)

Cash Flows from Operating Activities

The $85.2 million decrease in operating cash flows for the year ended December 31, 2020 compared to 2019, is primarily due the significant decline in revenues, which was partially offset by reductions in general and administrative costs and lease operating expenses as well as the other changes in working capital discussed previously.

See “—Consolidated Results of Operations” for further analysis of the changes in revenues and operating expenses, and see “Note 19—Employee Termination Benefits” to the accompanying consolidated financial statements included in Item 8 of this report for additional detail on cash paid for employee termination benefits.

Cash Flows from Investing Activities

During the year ended December 31, 2020, cash flows provided by investing activities primarily reflects $35.4 million of net cash proceeds primarily from the sale of the corporate office building, offset by cash payments made for capital expenditures coupled with the acquisition of $3.3 million primarily related to overriding royalty interests. See "Note 3— Acquisitions, Divestitures and Disposal of Assets and Oil and Gas Properties" to the accompanying consolidated financial statements included in Item 8 of this report for additional information.

During the year ended December 31, 2019, cash flows used in investing activities primarily consisted of capital expenditures for drilling and completion activities partially offset by proceeds from the sale of assets.

Capital Expenditures.

Our capital expenditures for the years ended December 31, 2020 and 2019, are summarized below (in thousands):

	Year Ended December 31,	
	2020	2019
Capital Expenditures		
Drilling, completion, and capital workovers	$ 3,563	$ 157,999
Leasehold and geophysical	1,005	3,790
Other - corporate	—	245
Capital expenditures, excluding acquisitions (on an accrual basis)	4,568	162,034
Acquisitions (1)	3,701	(236)
Current year total capital expenditures, including acquisitions	8,269	161,798
Change in capital accruals (2)	4,194	29,644
Total cash paid for capital expenditures	$ 12,463	$ 191,442

(1) Excludes $3.9 million and $5.4 million for the years ended December 31, 2020 and December 31, 2019, respectively, related to nonmonetary transactions.
(2) Reflects cash paid during the period presented for expenditures related to the prior year's capital program.

Capital expenditures, excluding acquisitions, for development and production activities decreased for the year ended December 31, 2020 compared to 2019, which is in line with the planned decrease in drilling and completion activity and related costs as reflected in our lower capital expenditures budget in 2020 and 2019.

Cash Flows from Financing Activities

Our financing activities used $39.0 in of cash for the year ended December 31, 2020, which consisted primarily of $57.5 million of net repayments of borrowings under the Prior Credit Facility partially offset by $20.0 million in proceeds from the New Credit Facility.

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Our financing activities provided $54.8 million of cash for the year ended December 31, 2019, which consisted primarily of proceeds from borrowings from our Prior Credit Facility during each period.

Indebtedness

Credit Facility

Credit Facility. On November 30, 2020, the Company entered into a $30 million New Credit Facility with the lenders party thereto and Icahn Agency Services LLC, as administrative agent (the "New Administrative Agent"). The New Credit Facility consists of a $10 million revolving loan facility and a $20 million term loan facility.

The New Credit Facility has two significant covenants, which require us to 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. These financial covenants are subject to customary cure rights. We were in compliance with all applicable financial covenants under the New Credit Facility as of December 31, 2020.

The New Credit Facility replaced the Company's Prior Credit Facility, dated as of February 10, 2017, as amended which was terminated effective November 30, 2020 and otherwise would have matured on April 1, 2021. The company used the $20.0 million term loan proceeds to repay the $12.0 million outstanding on the Prior Credit Facility on November 30, 2020.

We have approximately $10.0 million of available borrowing capacity under the New Credit Facility line of credit at December 31, 2020.

See "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 during 2020 and 2019.

Valuation Allowance

Upon emergence from bankruptcy and the application of fresh start accounting in 2016, our tax basis in property, plant, and equipment exceeded the book carrying value of our assets. Additionally, we had significant U.S. federal net operating losses remaining after the attribute reduction caused by the restructuring transactions. As such, the successor Company had significant deferred tax assets to consume upon emergence. We 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 fully realized and established a valuation allowance against our net deferred tax asset upon emergence and maintained the valuation allowance for the subsequent periods through December 31, 2020.

We continue to closely monitor all available evidence in considering whether to maintain a valuation allowance on our net deferred tax asset. Factors considered include, but are not limited to, the reversal periods of existing deferred tax liabilities and deferred tax assets, our historical earnings 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.

In determining whether to maintain the valuation allowance at December 31, 2020, we concluded that the objectively verifiable negative evidence of the presumption of cumulative negative earnings upon emergence and actual cumulative negative earnings for the Successor Company period ending December 31, 2020, is difficult to overcome with any forms of positive evidence that may exist. Accordingly, we have not changed our judgment regarding the need for a full valuation allowance against our net deferred tax asset for the period ending December 31, 2020.

See "Note 14—Income Taxes" to the accompanying consolidated financial statements for additional discussion of income tax related matters.

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 management 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. Estimates are based on historical experience and various other assumptions believed to be reasonable; however, actual results may differ significantly. The Company's critical accounting policies and additional information on significant estimates are discussed below. See "Note 1—Summary of Significant Accounting Policies" to the Company's accompanying consolidated financial statements in Item 8 of this report for additional discussion of significant accounting policies.

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. 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 91.5% of the Company's reserves were estimated by independent petroleum engineers for the year ended December 31, 2020. 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. 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, 2020 and 2019, the Company revised its proved reserves from prior years' reports by approximately (44.8) MMBoe and (58.5) MMBoe, respectively, due to decreases in SEC prices used to value reserves at the end of the applicable period, production performance indicating more (or less) reserves in place, 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 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.

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, unless it results in a greater than 10% change to the depletion rate.

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 and electrical infrastructure costs, net of accumulated depreciation, depletion and impairment, less related deferred income taxes, may not exceed an amount equal to the ceiling limitation. The Company calculates its full cost ceiling limitation using SEC prices adjusted for basis or location differentials, 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 Company recorded full cost ceiling impairment of $218.4 million for the year ended December 31, 2020 and $409.6 million for the year ended December 31, 2019. 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. For leases that do not have existing production that would otherwise extend the lease term, the Company estimates that any associated unproved costs will be evaluated and transferred to the amortization base of the full cost pool within a three to five year period from the original lease date. For leases that are held by production, the Company estimates that any associated unproved costs will be evaluated and transferred to the amortization base of the full cost pool within a 10-year period from the original lease date.

Property, Plant and Equipment, Net. Other capitalized costs including other property and equipment, such as electrical infrastructure assets and buildings, are carried at cost or the amortized fair value established on the 2016 bankruptcy emergence date. 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 7 to 39 years for buildings and 1 to 27 years for the electrical infrastructure assets and other 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. The carrying value of property and equipment is reviewed for possible impairment annually or 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.

See “—Consolidated Results of Operations” and “Note 9—Impairment” to the Company’s accompanying 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 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. Sales of oil, natural gas and NGLs are recorded at a point in time when control of the oil, natural gas and NGL production passes to the customer at the inlet of the processing plant or pipeline, or the delivery point for onloading to a delivery truck, net of royalties, discounts and allowances, as applicable. The Company deducts transportation costs from oil, natural gas and NGL revenues. Taxes assessed by governmental authorities on oil, natural gas and NGL sales are included in production, ad valorem and other taxes in the consolidated statements of operations. See "Note 16—Revenues" to the Company's accompanying consolidated financial statements in Item 8 of this report for further information on the Company's accounting policies related to revenues.

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, 2020, 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 1—Summary of Significant Accounting Policies” to the Company’s accompanying 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 our 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 we receive.

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, 2020, we had no open commodity derivative contracts.

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 a comparison of future prices to the contract price at the period-end.

The following table summarizes derivative activity for the years ended December 31, 2020 and 2019 (in thousands):

	Year Ended December 31,	
	2020	2019
(Gain) loss on commodity derivative contracts	$ (5,765)	$ (1,094)
Cash (received) paid on settlements	$ (5,879)	$ (6,266)

As of December 31, 2020, the Company had no derivative contracts.

See “Note 6—Derivatives” to the accompanying consolidated financial statements in Item 8 of this report for additional information regarding our commodity derivatives.

Credit Risk. We are exposed to credit risk related to counterparties to our derivative financial contracts. 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 have been with multiple counterparties to minimize exposure to any individual counterparty.

We do not require collateral or other security from counterparties to support derivative instruments. We have master netting agreements with each of our 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. Therefore, we are not required to post additional collateral under our commodity derivative contracts.

We are also exposed to credit risk related to the collection of receivables from our joint interest partners for their proportionate share of expenditures made on projects we operate. Historically, our credit losses on joint interest receivables have been immaterial.

Interest Rate Risk. We are exposed to interest rate risk on our New Credit Facility. This variable interest rate on our New Credit Facility fluctuates, and exposes us to short-term changes in market interest rates as our interest obligations on this instrument is periodically redetermined based on prevailing market interest rates, primarily LIBOR. We had $20.0 million in outstanding variable rate debt as of December 31, 2020.

Item 8. ***Financial Statements and Supplementary Data***

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, 2020. 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, 2020.

/s/ CARL F. GIESLER, JR.	/s/ SALAH GAMOUDI
Carl F. Giesler, Jr. **President and Chief Executive Officer**	**Salah Gamoudi** **Senior Vice President, Chief Financial Officer and Chief Accounting Officer**

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of SandRidge Energy, Inc. and subsidiaries (the "Company") as of December 31, 2020 and 2019, the related consolidated statement of operations, changes in stockholders' equity (deficit), and cash flows, for each of the two years in the period ended December 31, 2020, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2020, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

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

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

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

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Proved Oil and Natural Gas Properties, Depletion, and Impairment — Refer to Notes 1, 8, and 9 to the consolidated financial statements

Critical Audit Matter Description

The Company's proved and natural gas properties are amortized using the unit-of-production method and are evaluated for impairment using a ceiling limitation calculation. The development of the Company's oil and natural gas reserve quantities and the related future net revenues requires management to make significant estimates and assumptions related to the intent and ability to complete undeveloped proved reserves within a five-year development period, rates of production, and future development costs. As a result of changing market conditions, commodity prices and future development costs, assumptions can change from period to period, causing the estimates of proved reserves to change. The Company engages independent petroleum engineers to estimate oil and natural gas reserves using these estimates, assumptions, and engineering data. Changes in these assumptions could materially affect the Company's depreciation, depletion and impairment expenses. The proved oil and natural gas properties balance was $1.5 billion and the associated accumulated depreciation, depletion and impairment was $1.4 billion as of December 31, 2020. Depreciation, depletion- oil and natural gas expense was $50.3 million for the year ended December 31, 2020. Impairment was $218.4 million for the year ended December 31, 2020.

Given the significant judgments made by management, performing audit procedures to evaluate the Company's oil and natural gas reserve quantities and the related net revenues including management's estimates and assumptions related to forecasted rates of production requires a high degree of auditor judgment and an increased extent of effort.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures to address management's significant judgments and estimates associated with oil and natural gas reserves quantities and related future net revenues included the following, among others:

a. We evaluated the reasonableness of management's estimated reserve quantities by performing the following:

    i. Evaluating the experience, qualifications and objectivity of independent petroleum engineers.
    ii. For a sample of proved developed wells, we evaluated the well's expected forecasted production by comparing such the expected decline rate of production in future periods to historical production volumes and decline rates of the well.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 4, 2021

We have served as the Company's auditor since 2019.

SandRidge Energy, Inc. and Subsidiaries
Consolidated Balance Sheets

	December 31, 2020	December 31, 2019
	(In thousands)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 22,130	$ 4,275
Restricted cash - other	6,136	1,693
Accounts receivable, net	19,576	28,644
Derivative contracts	—	114
Prepaid expenses	2,890	3,342
Other current assets	80	538
Total current assets	50,812	38,606
Oil and natural gas properties, using full cost method of accounting		
Proved	1,463,950	1,484,359
Unproved	17,964	24,603
Less: accumulated depreciation, depletion and impairment	(1,375,692)	(1,129,622)
	106,222	379,340
Other property, plant and equipment, net	103,118	188,603
Other assets	680	1,140
Total assets	$ 260,832	$ 607,689
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued expenses	$ 51,426	$ 64,937
Asset retirement obligations	16,467	22,119
Other current liabilities	984	1,367
Total current liabilities	68,877	88,423
Long-term debt	20,000	57,500
Asset retirement obligations	40,701	52,897
Other long-term obligations	3,188	6,417
Total liabilities	132,766	205,237
Commitments and contingencies (Note 13)		
Stockholders' Equity		
Common stock, $0.001 par value; 250,000 shares authorized; 35,928 issued and outstanding at December 31, 2020 and 35,772 issued and outstanding at December 31, 2019	36	36
Warrants	88,520	88,520
Additional paid-in capital	1,062,220	1,059,253
Accumulated deficit	(1,022,710)	(745,357)
Total stockholders' equity	128,066	402,452
Total liabilities and stockholders' equity	$ 260,832	$ 607,689

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

SandRidge Energy, Inc. and Subsidiaries
Consolidated Statements of Operations

	Year Ended December 31,	
	2020	2019
	(In thousands, except per share amounts)	
Revenues		
Oil, natural gas and NGL	$ 114,450	$ 266,104
Other	526	741
Total revenues	114,976	266,845
Expenses		
Lease operating expenses	43,431	90,938
Production, ad valorem, and other taxes	9,634	19,394
Depreciation and depletion—oil and natural gas	50,349	146,874
Depreciation and amortization—other	7,736	11,684
Impairment	256,399	409,574
General and administrative	15,327	32,058
Restructuring expenses	2,733	—
Employee termination benefits	8,433	4,792
Gain on derivative contracts	(5,765)	(1,094)
Other operating (income) expense	206	(608)
Total expenses	388,483	713,612
Loss from operations	(273,507)	(446,767)
Other (expense) income		
Interest expense, net	(1,998)	(2,974)
Other (expense) income, net	(2,494)	436
Total other (expense) income	(4,492)	(2,538)
Loss before income taxes	(277,999)	(449,305)
Income tax benefit	(646)	—
Net loss	$ (277,353)	$ (449,305)
Loss per share		
Basic	$ (7.77)	$ (12.68)
Diluted	$ (7.77)	$ (12.68)
Weighted average number of common shares outstanding		
Basic	35,689	35,427
Diluted	35,689	35,427

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)

	Common Stock		Warrants		Additional Paid-In Capital	Accumulated Deficit	Total
	Shares	Amount	Shares	Amount			
				(In thousands)			
Balance at December 31, 2018	35,687	$ 36	6,604	$ 88,516	$ 1,055,164	$ (295,995)	$ 847,721
Issuance of stock awards, net of cancellations	40	—	—	—	—	—	—
Common stock issued for general unsecured claims	45	—	—	—	—	—	—
Stock-based compensation	—	—	—	—	4,460	—	4,460
Issuance of warrants for general unsecured claims	—	—	55	4	(4)	—	—
Cash paid for tax withholdings on vested stock awards	—	—	—	—	(367)	—	(367)
Cumulative effect of adoption of ASU 2016-02	—	—	—	—	—	(57)	(57)
Net loss	—	—	—	—	—	(449,305)	(449,305)
Balance at December 31, 2019	35,772	36	6,659	88,520	1,059,253	(745,357)	402,452
Issuance of stock awards, net of cancellations	96	—	—	—	—	—	—
Common stock issued for general unsecured claims	60	—	—	—	—	—	—
Stock-based compensation	—	—	—	—	3,031	—	3,031
Issuance of warrants for general unsecured claims	—	—	75	—	—	—	—
Cash paid for tax withholdings on vested stock awards	—	—	—	—	(64)	—	(64)
Net loss	—	—	—	—	—	(277,353)	(277,353)
Balance at December 31, 2020	35,928	$ 36	6,734	$ 88,520	$ 1,062,220	$ (1,022,710)	$ 128,066

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

SandRidge Energy, Inc. and Subsidiaries
Consolidated Statements of Cash Flows

	Year Ended December 31,	
	2020	2019
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net loss	$ (277,353)	$ (449,305)
Adjustments to reconcile net loss to net cash provided by operating activities		
Provision for doubtful accounts	3,202	16
Depreciation, depletion and amortization	58,085	158,558
Impairment	256,399	409,574
Debt issuance costs amortization	792	558
Write off of debt issuance costs	—	142
Gain on derivative contracts	(5,765)	(1,094)
Cash received (paid) on settlement of derivative contracts	5,879	6,266
Gain on sale of assets	(100)	—
Stock-based compensation	3,012	4,254
Other	149	(187)
Changes in operating assets and liabilities increasing (decreasing) cash		
Receivables	5,867	15,829
Prepaid expenses	452	(714)
Other current assets	458	(301)
Other assets and liabilities, net	1,134	(610)
Accounts payable and accrued expenses	(12,968)	(17,217)
Asset retirement obligations	(3,081)	(4,445)
Net cash provided by operating activities	36,162	121,324
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures for property, plant and equipment	(8,762)	(191,678)
Acquisitions of assets	(3,701)	236
Proceeds from sale of assets	37,556	1,593
Net cash provided by (used) in investing activities	25,093	(189,849)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from borrowings	59,000	211,096
Repayments of borrowings	(96,500)	(153,596)
Debt issuance costs	(160)	(911)
Reduction of financing lease liability	(1,233)	(1,374)
Cash paid for tax withholdings on vested stock awards	(64)	(367)
Net cash (used in) provided by financing activities	(38,957)	54,848
NET INCREASE (DECREASE) IN CASH, CASH EQUIVALENTS and RESTRICTED CASH	22,298	(13,677)
CASH, CASH EQUIVALENTS and RESTRICTED CASH, beginning of year	5,968	19,645
CASH, CASH EQUIVALENTS and RESTRICTED CASH, end of year	$ 28,266	$ 5,968

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

1. Summary of Significant Accounting Policies

Nature of Business. SandRidge Energy, Inc. is an oil and natural gas acquisition, development and production company headquartered in Oklahoma City, Oklahoma with a principal focus on developing and producing hydrocarbon resources in the United States.

Principles of Consolidation. The consolidated financial statements include the accounts of the Company and its wholly owned or majority owned subsidiaries, including its proportionate share of the Royalty Trust. All 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 NGL reserves; impairment tests of long-lived assets; the carrying value of unproved oil and natural gas properties; 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; valuation allowances for deferred tax assets; 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 from those estimates.

Going Concern Consideration. The accompanying consolidated financial statements are prepared in accordance with generally accepted accounting principles applicable to a going concern, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of business.

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. In addition, the Company maintains funds related to collateralize letters of credit and credit cards issued by lenders that were party to the Prior Credit Facility.

Accounts Receivable, Net. The Company has receivables for sales of oil, natural gas and NGLs, as well as receivables related to the drilling, completion, and production of 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 collectibility 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. Refer to Note 5 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, restricted cash, trade receivables, prepaid expenses, and trade payables and accrued expenses. The carrying values of cash, trade receivables and trade payables are considered to reflect fair values due to the short-term maturity of these instruments. See Note 4 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, third-party offers or prices of comparable assets with consideration of current market conditions to fair value its non-financial assets and liabilities when necessary.

Derivative Financial Instruments. The Company enters into oil and natural gas derivative contracts to manage risks related to fluctuations in prices of its expected oil and natural gas production. The Company considers current and anticipated market conditions, planned capital expenditures, and any debt service requirements when determining whether to enter into oil and gas derivative contracts. 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. The Company has elected not to designate price risk management activities as accounting hedges under applicable accounting guidance. 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 6 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, development, and production activities and capitalized interest. The Company capitalized gross internal costs of $0.7 million and $5.7 million during the years ended December 31, 2020 and 2019, 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 it has been determined that proved reserves exist or a lease is impaired. 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 amortized. The costs associated with unproved properties are primarily the costs to acquire unproved acreage. 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. 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 whether the proved reserves can be developed economically. 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 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 and electrical infrastructure assets, net of accumulated depreciation, depletion and impairment, less related deferred income taxes may not exceed the ceiling limitation. A ceiling limitation calculation is performed at the end of each quarter. If the ceiling limitation is exceeded, 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 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 SEC prices adjusted for basis or location differentials, held constant over the life of the reserves. If applicable, these 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. 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, unless it results in a greater than 10% change to the depletion rate.

Property, Plant and Equipment, Net. Other capitalized costs, including other property and equipment, such as electrical infrastructure assets and buildings, are carried at cost or the fair value established on the Emergence Date. 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 7 to 39 years for buildings and 1 to 27 years for the electrical infrastructure assets and other 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.

Realization of the carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that estimated future net operating cash flows directly related to the asset or asset group including disposal value 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 year ended December 31, 2020 the Company capitalized interest of approximately $0.7 million on unproved properties that were not currently being depreciated or depleted and on which exploration activities were in progress. During the year ended December 31, 2019 the Company capitalized interest of approximately $1.5 million on unproved properties that were not currently being depreciated or depleted and on which exploration activities were in progress.

Debt Issuance Costs. The Company includes unamortized line-of-credit debt issuance costs, if any, related to its New 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, if material. Debt issuance costs are amortized to interest expense over the term of the related debt. When debt is retired, any unamortized costs, if material are written off and included in gain or loss on extinguishment of debt.

Asset Retirement Obligations. The Company owns oil and natural gas assets that require expenditures to plug, abandon and remediate associated property at the end of their productive lives, in accordance with applicable federal and state laws. Liabilities for these asset retirement obligations are recorded at the estimated present value at the time the wells are drilled or acquired, 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 asset is sold and 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 are the timing of settlement and changes in the legal, regulatory, environmental and political environments, which are subject to change. See Note 12 for further discussion of the Company's asset retirement obligations.

Revenue Recognition and Natural Gas Balancing. Sales of oil, natural gas and NGLs are recorded at a point in time when control of the oil, natural gas and NGL production passes to the customer at the inlet of the processing plant or pipeline, or the delivery point for onloading to a delivery truck, net of royalties, discounts and allowances, as applicable. Additionally, the Company deducts transportation costs from oil, natural gas and NGL revenues. Taxes assessed by governmental authorities on oil, natural gas and NGL sales are included in production, ad valorem and other taxes in the consolidated statements of operations. See Note 16 for further information on the Company's accounting policies related to revenues.

The Company accounts for natural gas production imbalances using the sales method, which recognizes revenue on all natural gas sold even though the natural gas volumes sold may be more or less than the Company's ownership entitles it to sell. 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 of $1.1 million and $1.6 million at December 31, 2020 and 2019, respectively. The Company includes the gas imbalance positions in other long-term obligations in the consolidated balance sheets.

Allocation of Share-Based Compensation. 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.

Restructuring expenses. Restructuring expenses represent fees and costs associated with our outsourcing and relocation of certain corporate specific functions that are of a non-recurring nature, and expenses related to the 2016 bankruptcy.

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 resulting from the underpayment or late payment of income taxes due to a taxing authority or relating to income tax contingencies are presented as a component of the income tax provision, rather than as interest expense.

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 consist of unvested restricted stock awards, performance share units, warrants, and stock options using the treasury 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. 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 20 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. Environmental liabilities related to future costs are recorded on an undiscounted basis when assessments and/or remediation activities are probable and costs can be reasonably estimated. See Note 13 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, which 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 the credit ratings of its commodity derivative counterparties on an ongoing basis and considers their credit default risk ratings in determining the fair value of its commodity derivative contracts. The Company's commodity derivative contracts have been with multiple counterparties to minimize exposure to any individual counterparty.

The Company was not required to provide collateral to counterparties in order to secure commodity derivative instruments. The Company had master netting agreements with all of its commodity derivative counterparties, which allowed 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 was limited to the net amounts due from the counterparties under the commodity derivative contracts. The Company's loss was further limited as any amounts due from a defaulting counterparty that was a lender under the Prior Credit Facility could have been offset against any amounts owed to the same counterparty under the Prior Credit Facility.

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 are primarily 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.

Purchasers of the Company's oil, natural gas and NGL production consist primarily of independent marketers, large 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 its 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
December 31, 2020		
Plains Marketing, L.P.	$ 40,058	34.8 %
Targa Pipeline Mid-Continent West OK LLC	$ 38,287	33.3 %
Sinclair Crude Company	$ 36,375	31.6 %
December 31, 2019		
Targa Pipeline Mid-Continent West OK LLC	$ 85,780	32.1 %
Sinclair Crude Company	$ 74,810	28.0 %
Plains Marketing, L.P.	$ 69,214	25.9 %

Recently Adopted Accounting Pronouncements. Accounting Standards Updates ("ASU") 2016-13 - In March 2016, the FASB issued ASU 2016-13, "Financial Instruments —Credit Losses (Topic 326) Measurement of Credit Losses on Financial Instruments," which changes how entities will measure credit losses for most financial assets and certain other instruments that are not measured at fair value through net income. The standard replaced the previously required incurred loss approach with an expected loss model for instruments measured at amortized cost. The company adopted this ASU on January 1, 2020 using a modified retrospective approach; however, the impact was not material upon adoption.

Recent Accounting Pronouncements Not Yet Adopted. ASU 2020-04 - In March 2020, FASB issued ASU No. 2020-04, Reference Rate Reform (Topic 848), to facilitate the effects of reference rate reform on financial reporting. This ASU provides optional practical expedients and exceptions for applying US GAAP provisions to contracts, hedging relationships, and other transactions that reference LIBOR, or other reference rates expected to be discontinued because of reference rate reform, if certain criteria are met. The provisions of this ASU do not apply to contract modifications made and hedging transactions entered into or evaluated after December 31, 2022, except for hedging relationships existing as of December 31, 2022, that an entity has elected certain optional expedients for and that are retained through the end of the hedging relationship. The amendments in ASU 2020-04 are effective, for all entities, as of March 12, 2020 through December 31, 2022. The Company is currently reviewing the potential impact of the upcoming LIBOR reference rate change on its current contracts and hedging relationships and will determine the applicable provisions of ASU 2020-04.

ASU 2019-12 - In December 2019, the FASB issued ASU 2019-12, "Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes," which simplifies various aspects of accounting for income taxes, including requirements related to hybrid tax regimes, the tax basis step-up in goodwill obtained in a transaction that is not a business combination, separate financial statements of entities not subject to tax, the intraperiod tax allocation exception to the incremental approach, ownership changes in investments, interim-period accounting for enacted changes in tax laws, and year-to-date loss limitation in interim-period tax accounting. The standard is effective for interim and annual periods beginning after December 15, 2020, with early adoption permitted, and will be applied on a prospective basis. The Company is currently evaluating the effect the guidance will have on its consolidated financial statements.

2. Supplemental Cash Flow Information

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

	Year Ended December 31,	
	2020	2019
Supplemental Disclosure of Cash Flow Information		
Cash paid for interest, net of amounts capitalized	$ (1,260)	$ (2,157)
Cash received for income taxes	$ 616	$ —
Supplemental Disclosure of Noncash Investing and Financing Activities		
Purchase of PP&E in accounts payable	$ 396	$ 4,592
Right-of-use assets obtained in exchange for financing lease obligations	$ 67	$ 3,347
Carrying value of properties exchanged	$ 3,890	$ 5,384

3. Acquisitions, Divestitures and Disposal of Assets and Oil and Gas Properties

2020 Acquisitions and Divestitures

On September 10, 2020, the Company acquired all of the overriding royalty interests held by SandRidge Mississippian Royalty Trust II ("the Trust") for a net purchase price of $3.3 million, given our 37.6% ownership of the Trust. The Company accounted for this transaction as an asset acquisition and allocated the purchase price of the acquisition plus the transactions costs to oil and gas properties.

On August 31, 2020, the Company closed on the previously announced sale of its corporate headquarters building located in Oklahoma City, OK, for net proceeds of approximately $35.4 million. See Note 9 for additional discussion on the sale of the building.

2019 Acquisitions and Divestitures

Nonmonetary transaction. During the third quarter of 2019, the Company transferred its interest in certain proved oil and natural gas properties located in Comanche, Harper and Sumner counties in Kansas along with associated electrical infrastructure and an insignificant amount of accounts receivable with an aggregate estimated fair value of $5.4 million, for an interest in certain other proved oil and natural gas properties located in Comanche, Harper and Barber counties in Kansas. The fair value of the assets given in the transaction approximated their carrying value, therefore no gain or loss was recognized on the transfer.

4. 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 levels of the fair value hierarchy noted below. The carrying values of cash, restricted cash, accounts receivable, prepaid expenses, certain other current and non-current assets, accounts payable and accrued expenses and other current liabilities and other long-term obligations included in the consolidated balance sheets approximated fair value at December 31, 2020 and December 31, 2019. Additionally, the carrying amount of debt associated with borrowings outstanding under the New Credit Facility approximates fair value as borrowings bear interest at variable rates. As a result, these financial assets and liabilities are not discussed below.

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 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 Level 2 of the hierarchy as of December 31, 2019, as described below.

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.

Fair Value - Recurring Measurement Basis

There are no open commodity derivatives contracts as of December 31, 2020. The following table summarizes the Company’s assets and liabilities measured at fair value on a recurring basis by the fair value hierarchy (in thousands):

December 31, 2019

	Fair Value Measurements				
	Level 1	Level 2	Level 3	Netting(1)	Assets/Liabilities at Fair Value
Assets					
Commodity derivative contracts	$ —	$ 114	$ —	$ —	$ 114
	$ —	$ 114	$ —	$ —	$ 114

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

Transfers. During the years ended December 31, 2020 and 2019, the Company did not have any transfers between Level 1, Level 2 or Level 3 fair value measurements.

Fair Value of Non-Financial Assets and Liabilities

See Note 9 for discussion of the Company’s impairment valuations.

5. Accounts Receivable

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

	December 31,	
	2020	2019
Oil, natural gas and NGL sales	$ 12,757	$ 22,281
Joint interest billing	6,421	5,165
Other	4,754	2,315
Total accounts receivable	23,932	29,761
Less: allowance for doubtful accounts	(4,356)	(1,117)
Total accounts receivable, net	$ 19,576	$ 28,644

The following table presents the balance and activity in the allowance for doubtful accounts for the years ended December 31, 2020 and 2019 (in thousands):

	Year Ended December 31,	
	2020	2019
Beginning balance	$ 1,117	$ 1,295
Additions charged to costs and expenses (1)	3,239	6
Deductions (2)	—	(184)
Ending balance	$ 4,356	$ 1,117

(1) The Company performed an assessment of receivable balances related to governmental and other regulatory items during the year ended December 31, 2020, and recorded a $2.5 million allowance that is non-recurring in nature.

(2) Deductions represent the write-off of receivables and collections of amounts for which an allowance had previously been established.

6. Derivatives

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. On occasion, the Company has attempted to manage this risk on a portion of its forecasted oil or natural gas production sales through the use of commodity derivative contracts. The Company has not designated any of its derivative contracts as hedges for accounting purposes. All derivative contracts are recorded at fair value with changes in derivative contract fair values recognized as gain or loss on derivative contracts in the consolidated statements of operations. 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. Commodity derivative contracts are settled on a monthly basis, and the commodity derivative contract valuations are adjusted to the mark-to-market valuation on a quarterly basis.

The following table summarizes derivative activity for the years ended December 31, 2020 and 2019 (in thousands):

	Year Ended December 31,	
	2020	2019
Gain on commodity derivative contracts	$ (5,765)	$ (1,094)
Cash received on settlements	$ (5,879)	$ (6,266)

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, 2019, the counterparties to the Company’s open commodity derivative contracts consisted of three financial institutions, all of which were also lenders under the Company’s Prior Credit Facility. The Company was not required to post additional collateral under its commodity derivative contracts as all of the counterparties to the Company’s commodity derivative contracts shared in the collateral supporting the Company’s Prior Credit Facility.

There are no open commodity derivatives contracts as of December 31, 2020. The following table summarizes (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 Prior Credit Facility as of December 31, 2019 (in thousands):

December 31, 2019

	Gross Amounts	Gross Amounts Offset	Amounts Net of Offset	Financial Collateral	Net Amount
Assets					
Derivative contracts - current	$ 114	$ —	$ 114	$ —	$ 114
Total	$ 114	$ —	$ 114	$ —	$ 114

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	December 31, 2019
Derivative assets		
Oil price swaps	Derivative contracts - current	$ 114
Natural gas price swaps	Derivative contracts - current	$ —
Total net derivative contracts		$ 114

See Note 4 for additional discussion of the fair value measurement of the Company's derivative contracts.

7. Leases

Topic 842 provides practical expedients to assist with the transition to the new standard. The Company elected the 'package of practical expedients,' and therefore did not have to reassess prior conclusions about lease identification, lease classification and initial indirect costs. The Company also elected the land easement practical expedient and short-term lease recognition exemption, under which leases with initial terms less than 12 months are not required to be presented on the balance sheet. The Company further elected the practical expedient to combine lease and non-lease components for asset classes including drilling rigs, compressors and various office equipment.

The Company determines if an arrangement is or contains a lease at inception. A lease is defined as a contract, or part of a contract, that conveys the right to control the use of identified property, plant or equipment for a period of time in exchange for consideration. Lease liabilities were recognized based on the present value of the lease payments not yet paid over the lease term at January 1, 2019 for existing leases and at the commencement date for any new leases entered into subsequent to January 1, 2019. As most of the Company's leases do not provide an implicit rate, the Company's incremental borrowing rate was used as the discount rate when determining the present value of future payments. Lease assets are recognized based on the lease liability plus any prepaid lease payments and excluding lease incentives and initial direct costs incurred for the same periods. The Company's lease terms may include options to extend or terminate the lease when it is reasonably certain that option will be exercised. Lease expense for minimum lease payments is recognized on a straight-line basis over the lease term.

Operating leases are included in other assets, other current liabilities and other long-term obligations, and finance leases are included in other property, plant and equipment, other current liabilities and other long-term obligations on the accompanying consolidated balance sheet as of December 31, 2020.

The Company had operating and financing leases for vehicles and equipment outstanding during the year ended December 31, 2020, which were not significant to the consolidated financial statements.

The components of lease costs recognized for the Company's ROU leases are shown below (in thousands):

	Year Ended December 31, 2020	Year Ended December 31, 2019
Short-term lease cost (1)	$ 1,880	$ 9,994
Financing lease cost	1,220	1,397
Operating lease cost	169	188
Total lease cost	$ 3,269	$ 11,579

(1) There were no short-term lease costs capitalized as part of oil and natural gas properties during the year ended December 31, 2020 and $4.8 million in 2019. Portions of these costs were reimbursed to the Company by other working interest owners.

8. Property, Plant and Equipment

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

	December 31,	
	2020	2019
Oil and natural gas properties		
Proved	$ 1,463,950	$ 1,484,359
Unproved	17,964	24,603
Total oil and natural gas properties	1,481,914	1,508,962
Less accumulated depreciation, depletion and impairment	(1,375,692)	(1,129,622)
Net oil and natural gas properties capitalized costs	106,222	379,340
Land	200	4,400
Electrical infrastructure	121,819	126,482
Non-oil and natural gas equipment	1,563	12,665
Buildings and structures	3,603	77,148
Financing Leases	1,051	2,109
Total	128,236	222,804
Less accumulated depreciation and amortization	(25,118)	(34,201)
Other property, plant and equipment, net	103,118	188,603
Total property, plant and equipment, net	$ 209,340	$ 567,943

The average rates used for depreciation and depletion of oil and natural gas properties were $5.11 per Boe in 2020 and $12.28 per Boe in 2019.

See Note 9 for discussion of impairment of other property, plant and equipment.

Costs Excluded from Amortization

The costs excluded from amortization was related to unproved properties, which were excluded from oil and natural gas properties subject to amortization at December 31, 2020 and 2019 were $18.0 million and $24.6 million, respectively.

For leases that do not have existing production that would otherwise extend the lease term, the Company estimates that any associated unproved costs will be evaluated and transferred to the amortization base of the full cost pool within a three to five year period from the original lease date. For leases that are held by production, the Company estimates that any associated unproved costs will be evaluated and transferred to the amortization base of the full cost pool within a 10-year period from the original lease date. In addition, the Company’s internal engineers evaluate all properties on a quarterly basis.

9. Impairment

The Company assesses the need to impair its oil and gas properties during its quarterly full cost pool ceiling limitation calculation. The Company analyzes various property, plant and equipment for impairment when certain triggering events occur by comparing the carrying values of the assets to their estimated fair values. The full cost pool ceiling limitation and estimated fair values of drilling, midstream, and other assets were determined in accordance with the policies discussed in Note 1.

Impairment for the years ended December 31, 2020 and 2019 consists of the following (in thousands):

	Year Ended December 31,	
	2020	2019
Full cost pool ceiling limitation	$ 218,399	$ 409,574
Other	38,000	—
	$ 256,399	$ 409,574

The ceiling limitation impairment charges recorded for the year ended December 31, 2020 resulted from various factors, including a decrease in proved reserve value driven by a significant decline in the trailing twelve-month weighted average oil and natural gas prices in the first, second and third quarters of 2020. Impairment recorded in the year ended December 31, 2019 largely resulted from a decrease in the trailing twelve-month weighted average SEC prices for oil and natural gas prices in 2019, lower NGL prices, increases in expected operating expenses, and other less significant inputs. See Note 21 for additional discussion of our oil and gas producing properties. For the quarter ended December 31, 2020, we recorded a full cost ceiling limitation impairment charge of $2.6 million.

The asset impairment charge of $38.0 million recorded for the year ended December 31, 2020 resulted from the write down of the net carrying amount of the office headquarters building assets to their estimated fair value less estimated costs to sell the building. In May 2020, the Company entered into an agreement for the sale of its corporate headquarters building located in Oklahoma City, OK. The building sale closed on August 31, 2020.

In accordance with the applicable accounting guidance, FASB ASC 360-10-45-9, the Company reclassified its corporate headquarters building net carrying amount from Other property, plant and equipment, net, to Assets held for sale on the Consolidated Balance Sheet at June 30, 2020. The Company also reclassified the liabilities associated with the corporate headquarters building from Accounts payable and accrued expenses to Liabilities held for sale on the Consolidated Balance Sheet at June 30, 2020. Further, the Company recorded an impairment charge of $38.0 million in the three-month period ended June 30, 2020 to write down the net carrying amount of the office headquarters building assets to their estimated fair value less estimated costs to sell the building. No impairment charges were recorded for the corporate headquarters building assets for the year ended December 31, 2019.

Prior to the sale of the corporate headquarters building, the carrying amount of the building was assessed for recoverability and impairment using undiscounted cash flow measures of the consolidated Company as prescribed under ASC 360-10-35, rather than fair value as prescribed under ASC 360-10-45-9.

10. Accounts Payable and Accrued Expenses

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

	December 31,	
	2020	2019
Accounts payable and other accrued expenses	$ 23,017	$ 29,423
Production payable	15,367	22,530
Payroll and benefits	5,640	7,021
Taxes payable	6,864	4,988
Drilling advances	477	514
Accrued interest	61	461
Total accounts payable and accrued expenses	$ 51,426	$ 64,937

11. Long-Term Debt

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

	December 31,	
	2020	2019
New Credit Facility - Term Loan	$ 20,000	$ —
Prior Credit Facility	—	57,500
Total debt	20,000	57,500
Less: current maturities of long-term debt	—	—
Long-term debt	$ 20,000	$ 57,500

Credit Facility. On November 30, 2020 the Company entered into a $30 million credit facility with a related party and affiliate of Icahn Enterprises and Icahn Agency Services LLC, as administrative agent (the "New Administrative Agent"). The New Credit Facility matures on November 30, 2023. The New Credit Facility consists of a $10 million revolving loan facility and a $20 million term loan facility. At December 31, 2020, the Company had a $20.0 million term loan outstanding under the New Credit Facility and $10.0 million available to be drawn under the New Credit Facility.

The New Credit Facility replaced the Company's Prior Credit Facility, dated February 10, 2017, as amended which was terminated effective November 30, 2020 and otherwise would have matured on April 1, 2021. The company used the $20.0 million term loan proceeds to repay the $12.0 million outstanding on the Prior Credit Facility on November 30, 2020.

There are no scheduled borrowing base redeterminations under the New Credit Facility. The outstanding borrowings under the New Credit Facility bear interest at a rate tied to a utilization ratio of (a) LIBOR plus an applicable margin that varies from 200 to 300 basis points or (b) the base rate plus an applicable margin that varies from 100 basis points to 200 basis points. During the year ended December 31, 2020, the weighted average interest rate paid for borrowings outstanding under both the outstanding Prior Credit Facility and the New Credit Facility was approximately 3.2%.

The Company has the right to prepay loans under the New Credit Facility at any time without a prepayment penalty, other than customary "breakage" costs with respect to LIBOR loans.

Furthermore, the New Credit Facility is secured by (i) first-priority mortgages on at least 95% of the PV-9 pricing of the 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 (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 Credit Facility includes events of default and certain customary affirmative and negative covenants. The Company is required maintain certain financial covenants, commencing with the first full quarter ending after the effective date thereof to, 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. As of December 31, 2020, the Company was in compliance with all applicable covenants and had a consolidated total net leverage ratio of (0.15) and consolidated interest coverage ratio of 26.71.

During the year ended December 31, 2020, the Company paid a related party, an affiliate of Icahn Enterprises, an immaterial amount of interest expense which is included on the Interest expense, net line item on the Consolidated Statement of Operations. The total outstanding balance of the New Credit facility is recorded in long-term debt on the consolidated balance sheet as of December 31, 2020.

The Prior Credit Facility was amended and restated on June 21, 2019 and had a borrowing base of $75.0 million when it was terminated. The interest rate on outstanding borrowings under the restated credit facility was determined by a pricing grid tied to borrowing base utilization of (a) LIBOR plus an applicable margin that varies from 2.00% to 3.00% per annum, or (b) the base rate plus an applicable margin that varies from 1.00% to 2.00% per annum. Quarterly, the Company paid commitment fees assessed at annual rates of 0.50% on any available portion of the Prior Credit Facility.

12. Asset Retirement Obligations

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

	Year Ended December 31,	
	2020	2019
Beginning balance	$ 75,016	$ 60,064
Liability incurred upon acquiring and drilling wells	309	2,771
Revisions in estimated cash flows (1)	(17,192)	12,208
Liability settled or disposed in current period	(6,866)	(5,379)
Accretion	5,901	5,352
Ending balance	57,168	75,016
Less: current portion	16,467	22,119
Asset retirement obligations, net of current	$ 40,701	$ 52,897

(1) Revisions for the years ended December 31, 2020 and 2019 relate primarily to changes in estimated well lives due to changes in oil and natural gas prices and changes in plugging cost estimates.

13. Commitments and Contingencies

Included below is a discussion of the Company's various future commitments and contingencies as of December 31, 2020. The commitments and contingencies under these arrangements are not recorded in the accompanying consolidated balance sheets. At December 31, 2020 the Company's only material commitment in each of the next five years and beyond is its asset retirement obligations. See Note 12. for additional discussions.

Legal Proceedings. As previously disclosed, on May 16, 2016, the Company and certain of its direct and indirect subsidiaries (collectively, the "Debtors") filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court"). The Bankruptcy Court confirmed the joint plan of organization (the "Plan") of the Debtors on September 9, 2016, and the Debtors subsequently emerged from bankruptcy on October 4, 2016.

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

- *In re SandRidge Energy, Inc. Securities Litigation*, Case No. 5:12-cv-01341-LRW, USDC, Western District of Oklahoma; and

- *Ivan Nibur, Lawrence Ross, Jase Luna, Matthew Willenbucher, and the Duane & Virginia Lanier Trust v. SandRidge Mississippian Trust I, et al*., Case No. 5:15-cv-00634-SLP, USDC, Western District of Oklahoma

The lead plaintiffs in both In re SandRidge Energy, Inc. Securities Litigation and Lanier Trust assert claims on behalf of themselves and (i) in In re SandRidge Energy, Inc. Securities Litigation, a class of all purchasers of SandRidge common stock from February 24, 2011 and November 8, 2012 under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, and Rule 10b-5 promulgated thereunder, and (ii) in Lanier Trust, a putative class of purchasers of SandRidge Mississippian Trust I and SandRidge Mississippian Trust II common units between April 7, 2011 and November 8, 2012 under Sections 11, 12(a)(2), and 15 of the Securities Act of 1933 and Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, and Rule 10b-5 promulgated thereunder, both based on allegations that defendants, which include certain former officers of the Company and the SandRidge Mississippian Trust I, made misrepresentations or omissions concerning various topics including the performance of wells operated by the Company in the Mississippian region.

Discovery in each of the Cases closed on June 19, 2019. Following a hearing on class certification in each of the Cases on September 6, 2019, the court granted class certification in In re SandRidge Energy, Inc. Securities Litigation on September

30, 2019. The motion for class certification in Lanier Trust remains pending. On April 2, 2020, the individual defendants and SandRidge Mississippian Trust I filed motions for summary judgment seeking the dismissal of all claims asserted against them in the Lanier Trust matter. On the same date, the individual defendants filed motions for summary judgment seeking the dismissal of all claims asserted against them In re SandRidge Energy, Inc. Securities Litigation. The motions remain pending.

In each of the Cases, lead plaintiffs seek to recover unspecified damages, interest, costs and expenses incurred in the litigation on behalf of themselves and class members. Although the claims against the Company in each Case have been discharged pursuant to the Plan, the Company remains a nominal defendant. The Company may also be contractually obligated to indemnify two former officers who are defendants and the SandRidge Mississippian Trust I against losses, claims, damages, liabilities and expenses, including reasonable costs of investigation and attorney's fees and expenses, which it is required to advance, arising out of the Cases, although the Company disputes any such obligations. Such indemnification is not covered by insurance with respect to the Trust. As of October 2020, we have exhausted all remaining insurance coverage for the costs of indemnification and expect no further reimbursements.

In light of the status of the Cases, and the facts, circumstances and legal theories relating thereto, the Company is not able to determine the likelihood of an outcome in either case or provide an estimate of any reasonably possible loss or range of possible loss related thereto. However, considering the exhaustion of insurance coverage available to the Company, such losses, if incurred, could be material. The Company has not established any liabilities relating to the Cases and believes that the plaintiffs' claims are without merit. The Company intends to continue to vigorously defend against the Cases in its capacity as a nominal defendant.

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.

14. Income Taxes

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

	Year Ended December 31,	
	2020	2019
Current		
Federal	$ (646)	$ —
State	—	—
	(646)	—
Deferred		
Federal	—	—
State	—	—
	—	—
Total (benefit) provision	$ (646)	$ —

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

	Year Ended December 31,	
	2020	2019
Computed at federal statutory rate	$ (58,574)	$ (94,354)
State taxes, net of federal benefit	(10,898)	(20,500)
Non-deductible expenses	18	137
Stock-based compensation	643	602
Return to provision adjustments	(945)	(6,096)
Refund of AMT Sequestration	(646)	—
Change in valuation allowance	69,285	120,211
Other	471	—
Total (benefit) provision	$ (646)	$ —

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. 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 remaining net deferred tax asset at December 31, 2019 and December 31, 2020.

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

	December 31, 2020	December 31, 2019
Deferred tax liabilities		
Investments (1)	$ 34,816	$ 109,289
Derivative contracts	—	29
Total deferred tax liabilities	34,816	109,318
Deferred tax assets		
Property, plant and equipment	317,063	300,704
Net operating loss carryforwards	365,772	383,418
Tax credits and other carryforwards	33,538	34,148
Asset retirement obligations	15,216	18,747
Other	2,500	2,290
Total deferred tax assets	734,089	739,307
Valuation allowance	(699,273)	(629,989)
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 a result of the Chapter 11 reorganization and related transactions, the Company experienced an ownership change within the meaning of IRC Section 382 during 2016 that subjected certain of the Company’s tax attributes, including net operating losses ("NOLs"), to an IRC Section 382 limitation. This limitation has not resulted in cash taxes for any period subsequent to the ownership change. Since the 2016 ownership change, the Company has generated additional NOLs and other tax attributes that are not currently subject to an IRC Section 382 limitation. The Company's ability to use NOLs and other tax attributes to reduce taxable income and income taxes could be materially impacted by a future IRC 382 ownership change. Future transactions involving the Company's stock including those outside of the Company's control could cause an IRC 382 ownership change resulting in a limitation on tax attributes currently not limited and a more restrictive limitation on tax attributes currently subject to the previous IRC 382 limitation.

As of December 31, 2020, the Company had approximately $1.4 billion of federal NOL carryforwards, net of NOLs expected to expire unused due to the 2016 IRC Section 382 limitation. Of the $1.4 billion of federal NOL carryforwards, $0.8 billion expire during the years 2025 through 2037, while $0.6 billion do not have an expiration date. Additionally, the Company had federal tax credits in excess of $33.5 million which begin expiring in 2029.

The Company did not have unrecognized tax benefits at December 31, 2020 or 2019.

The Company’s only taxing jurisdiction is the United States (federal and state). The Company’s tax years 2016 to present remain open for federal examination. Additionally, tax years 2005 through 2016 remain subject to examination for the purpose of determining the amount of federal NOL and other carryforwards. The number of years open for state tax audits varies, depending on the state, but is generally from three to five years.

On March 27, 2020, the President of the United States signed into law the Coronavirus Aid, Relief, and Economic Security (“CARES”) Act. The CARES Act provides relief to corporate taxpayers by permitting a five year carryback of 2018-2020 NOLs, removing the 80% limitation on the carryback of those NOLs, increasing the Section 163(j) 30% limitation on interest expense deductibility to 50% of adjusted taxable income for 2019 and 2020, and accelerates refunds for minimum tax credit carryforwards. Further, on December 27, 2020, the President of the United States signed into law the Consolidated Appropriations Act, 2021 (“Appropriations Act”). During the year ended December 31, 2020, no material adjustments were made to provision amounts recorded as a result of the enactment of the CARES Act or the Appropriations Act.

In July 2020, the U.S. Treasury Department released final and proposed regulations on IRC Section 163(j) which limits business interest expense deductions. These regulations apply to tax years beginning January 1, 2021. However, taxpayers may choose to apply these regulations to tax years beginning after December 31, 2017. The Company plans to adopt the final regulations for the year ended December 31, 2020. This does not result in any material impact to the provision.

15. Equity

Common Stock and Performance Share Units. At December 31, 2020, the Company had 35.9 million shares of common stock, par value $0.001 per share, issued and outstanding, including 0.1 million shares of unvested restricted stock awards, and 250.0 million shares of common stock authorized. The Company also has 0.2 million of performance share units and 0.1 million stock options outstanding at December 31, 2020 as discussed further in Note 17.

Warrants. Since the fourth quarter of 2016, the Company has issued approximately 4.7 million Series A warrants and 2.0 million Series B warrants to certain holders of general unsecured claims as defined in the 2016 bankruptcy reorganization plan. These warrants are exercisable until October 4, 2022 for one share of 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. The warrants contain customary anti-dilution adjustments in the event of any stock split, reverse stock split, reclassification, stock dividend or other distributions.

The Tax Benefits Preservation Plan. On July 1, 2020, the Board declared a dividend distribution of one right (a "Right") for each outstanding share of Company common stock, par value $0.001 per share to stockholders of record at the close of business on July 13, 2020. Each Right entitles its holder, under certain circumstances, to purchase from the Company one one-thousandth of a share of Series A Junior Participating Preferred Stock of the Company, par value $0.001 per share, at an exercise price of $5.00 per Right, subject to adjustment. The description and terms of the Rights are set forth in the tax benefits preservation plan, dated as of July 1, 2020, between the Company and American Stock Transfer & Trust Company, LLC, as rights agent (and any successor rights agent, the "Rights Agent").

The Company adopted the Tax Benefits Preservation Plan in order to protect shareholder value against a possible limitation on the Company's ability to use its tax net operating losses (the "NOLs") and certain other tax benefits to reduce potential future U.S. federal income tax obligations. The NOLs are a valuable asset to the Company, which may inure to the benefit of the Company and its stockholders. However, if the Company experiences an "ownership change," as defined in Section 382 of the Internal Revenue Code of 1986, as amended (the "Code"), its ability to fully utilize the NOLs and certain other tax benefits will be substantially limited and the timing of the usage of the NOLs and such other benefits could be substantially delayed, which could significantly impair the value of those assets. Generally, an "ownership change" occurs if the percentage of the Company's stock owned by one or more of its "five-percent shareholders" (as such term is defined in Section 382 of the Code) increases by more than 50 percentage points over the lowest percentage of stock owned by such stockholder or stockholders at any time over a three-year period. The Tax Benefits Preservation Plan is intended to prevent against such an "ownership change" by deterring any person or group from acquiring beneficial ownership of 4.9% or more of the Company's securities.

Subject to certain exceptions, the Rights become exercisable and trade separately from Common Stock only upon the "Distribution Time," which occurs upon the earlier of:

- the close of business on the tenth (10th) day after the "Stock Acquisition Date," which is (a) the first date of public announcement that a person or group of affiliated or associated persons (with certain exceptions, an "Acquiring Person") has acquired, or obtained the right or obligation to acquire, beneficial ownership of 4.9% or more of the outstanding shares of Common Stock (with certain exceptions) or (b) such other date, as determined by the Board, on which a person or group has become an Acquiring Person, or

- the close of business on the tenth (10th) business day (or later date as may be determined by the Board prior to such time as any person or group becomes an Acquiring Person) following the commencement of a tender offer or exchange offer which, if consummated, would result in a person or group becoming an Acquiring Person.

Any existing stockholder or group that beneficially owns 4.9% or more of Common Stock has been grandfathered at its current ownership level, but the Rights will not be exercisable if, at any time after the announcement of the Tax Benefits Preservation Plan, such stockholder or group increases its ownership of Common Stock by one share of Common Stock. Certain synthetic interests in securities created by derivative positions, whether or not such interests are considered to be ownership of the underlying Common Stock or are reportable for purposes of Regulation 13D of the Securities Exchange Act of 1934, as amended, are treated as beneficial ownership of the number of shares of Common Stock equivalent to the economic exposure created by the derivative position, to the extent actual shares of Common Stock are directly or indirectly held by counterparties to the derivatives contracts.

Until the earlier of the Distribution Time and the Expiration Time, the surrender for transfer of any shares of Common Stock will also constitute the transfer of the Rights associated with those shares. As soon as practicable after the Distribution Time, separate rights certificates will be mailed to holders of record of Common Stock as of the close of business on the Distribution Time. From and after the Distribution Time, the separate rights certificates alone will represent the Rights. Except as otherwise provided in the Tax Benefits Preservation Plan, only shares of Common Stock issued prior to the Distribution Time will be issued with Rights. The Rights are not exercisable until the Distribution Time.

The Tax Benefits Preservation Plan will expire on the earliest of: (i) the close of business on the day following the certification of the voting results of the Company's 2021 annual meeting of stockholders or any prior special meeting of stockholders, if at such stockholder meeting a proposal to approve this Agreement has not been passed by the affirmative vote of the holders of at least majority of the shares of Common Stock entitled to vote at the 2021 annual meeting of stockholders or any other meeting of the stockholders of the Company duly held prior to such meeting, (ii) the time at which the Rights are redeemed pursuant to the Tax Benefits Preservation Plan, (iii) the time at which the Rights are exchanged pursuant to the Tax Benefits Preservation Plan, (iv) the closing of any merger or other acquisition transaction involving the Company pursuant to an agreement of the type described in Section 13(f) of the Tax Benefits Preservation Plan, at which time, the Rights are terminated, (v) the time at which the Board determines that the NOLs are utilized in all material respects or that an ownership change under Section 382 would not adversely impact in any material respect the time period in which the Company could use the NOLs, or materially impair the amount of the NOLs that could be used by the Company in any particular time period, for applicable tax purposes and (vi) the Close of Business on July 1, 2023 (the earliest of (i), (ii), (iii), (iv), (v), and (vi) being herein referred to as the "Expiration Time").

In the event that any person or group (other than certain exempt persons) becomes an Acquiring Person (a "Flip-in Event"), each holder of a Right (other than any Acquiring Person and certain related parties, whose Rights automatically become null and void) will have the right to receive, upon exercise, shares of Common Stock having a value equal to two times the exercise price of the Right.

In the event that, at any time following the Stock Acquisition Date, any of the following occurs (each, a "Flip-over Event"):

- the Company consolidates with, or merges with and into, any other entity, and the Company is not the continuing or surviving entity
- any entity engages in a share exchange with or consolidates with, or merges with or into, the Company, and the Company is the continuing or surviving entity and, in connection with such share exchange, consolidation or merger, all or part of the outstanding shares of Common Stock are changed into or exchanged for stock or other securities of any other entity or cash or any other property; or
- the Company sells or otherwise transfers, in one transaction or a series of related transactions, fifty percent (50%) or more of the Company's assets, cash flow or earning power, each holder of a Right (except Rights which previously have been voided as described above) will have the right to receive, upon exercise, common stock of the acquiring company having a value equal to two times the exercise price of the Right.

Shares Withheld for Taxes. 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.

	Year Ended December 31,	
	2020	2019
Number of shares withheld for taxes	51	56
Value of shares withheld for taxes	$ 64	$ 367

16. Revenues

The following table disaggregates the Company's revenue by source for the years ended December 31, 2020 and 2019 (in thousands):

	Year Ended December 31,	
	2020	2019
Oil	$ 73,621	$ 186,360
NGL	17,962	35,598
Natural gas	22,867	44,146
Other	526	741
Total revenues	$ 114,976	$ 266,845

Oil, natural gas and NGL revenues. A majority of the Company's revenues come from sales of oil, natural gas and NGLs. In accordance with the contracts governing these sales, performance obligations to customers are satisfied and revenues are recorded at a point in time when control of the oil, natural gas and NGL production passes to the customer at the inlet of the processing plant or pipeline, or the delivery point for onloading to a delivery truck. As the Company's customers obtain control of the production prior to selling it to other end customers, the Company presents its revenues on a net basis, rather than on a gross basis.

Pricing for the Company's oil, natural gas and NGL contracts is variable and is based on volumes sold multiplied by either an index price, net of deductions, or a percentage of the sales price obtained by the customer, which is also based on index prices. The transaction price is allocated on a pro-rata basis to each unit of oil, natural gas or NGL sold based on the terms of the contract. Oil, natural gas and NGL revenues are also recorded net of royalties, discounts and allowances, and transportation costs, as applicable. Taxes assessed by governmental authorities on oil, natural gas and NGL sales are presented separately from revenues and are included in production, ad valorem, and other taxes expense in the consolidated statements of operations.

Revenues Receivable. The Company records an asset in accounts receivable, net on its consolidated balance sheet for revenues receivable from contracts with customers at the end of each period. Pricing for revenues receivable is estimated using current month crude oil, natural gas and NGL prices, net of deductions. Revenues receivable are typically collected the month after the Company delivers the related production to its customers. As of December 31, 2020 and 2019 the Company had revenues receivable of $12.8 million and $22.3 million, respectively, and did not record any bad debt expense on revenues receivable during the year ended December 31, 2020.

17. Share-Based Compensation

Share-Based Compensation

Omnibus Incentive Plan. The Omnibus Incentive Plan became effective on October 4, 2016 and authorizes the issuance of up to 4.6 million shares of SandRidge common stock.

Persons eligible to receive awards under the Omnibus Incentive Plan include non-employee directors of the Company, employees of the Company or any of its affiliates, and certain consultants and advisors to the 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 common stock, as well as certain cash-based awards. At December 31, 2020, the Company had restricted stock awards, restricted stock units, performance share units and stock options outstanding under the Omnibus Incentive Plan. Forfeitures for these awards are recognized as they occur.

Restricted Stock Awards. The Company's restricted stock awards are equity-classified awards and are valued based upon the market value of the Company's common stock on the date of grant. Outstanding restricted shares at December 31, 2020 will generally vest over either a one-year period or three-year period with a remaining weighted average contractual period of 0.5 years and have $0.3 million of associated unrecognized compensation cost.

The following table presents a summary of the Company’s unvested restricted stock awards:

	Number of Shares (In thousands)	Weighted-Average Grant Date Fair Value
Unvested restricted shares outstanding at December 31, 2018	365	$ 16.07
Granted	93	$ 8.06
Vested	(210)	$ 16.29
Forfeited / Canceled	(15)	$ 16.25
Unvested restricted shares outstanding at December 31, 2019	233	$ 12.66
Granted	105	$ 2.15
Vested (1)	(174)	$ 11.53
Forfeited / Canceled	(50)	$ 15.97
Unvested restricted shares outstanding at December 31, 2020	114	$ 3.26

(1) The aggregate intrinsic value of restricted stock that vested during 2020 was approximately $0.2 million based on the stock price at the time of vesting.

Restricted Stock Units. The Company’s restricted stock units awards are equity-classified awards and are valued based upon the market value of the Company’s common stock on the date of grant. Outstanding restricted stock units at December 31, 2020 will generally vest over a three-year period with a remaining weighted average contractual period of 2.42 years and have $1.2 million associated unrecognized compensation cost at year in December 31, 2020. Compensation expense was $0.3 million. The following table presents a summary of the Company's restricted stock units:

	Number of Units (In thousands)	Weighted-Average Grant Date Fair Value
Unvested restricted stock units outstanding at December 31, 2019	—	—
Granted	1,410	1.10
Unvested restricted stock units outstanding at December 31, 2020	1,410	$ 1.10

Performance Share Units. In September 2018, the Company granted an immaterial number of additional performance share units. The vesting for the performance share units issued in 2018 was accelerated in connection with executive terminations in third quarter of 2020. In August 2020, the Company granted additional performance share units. Outstanding performance share units at December 31, 2020 will generally vest over a three year period with a remaining weighted average contractual period of 2.69 years and $0.3 million unrecognized compensation cost at year in December 31, 2020. Compensation expense was immaterial. The following table presents a summary of the Company's performance share units:

	Number of Units (In thousands)	Weighted-Average Grant Date Fair Value
Unvested performance share units outstanding at December 31, 2018	111	$ 20.41
Vested	(19)	15.11
Unvested performance share units outstanding at December 31, 2019	92	20.41
Granted	205	1.66
Vested (1)	(92)	$ 20.41
Unvested performance share units outstanding at December 31, 2020	205	$ 1.66

(1) The aggregate intrinsic value of performance share units that vested during 2020 was approximately $0.1 million.

Stock Options

The fair value of stock options is estimated on the date of the grant using a Black-Scholes valuation model that uses the weighted average assumptions noted in the following table. Expected volatility is based on historical volatility of the Company's common stock and other factors. The Company uses historical data on the exercise of stock options, post-vesting forfeitures and other factors to estimate the expected term of the stock-based payments granted. The risk-free interest rate is based on the U.S. Treasury yield curve in effect at the time of grant. Generally, stock options granted to employees and directors vest ratably over three years from the grant date and expire seven years from the date of grant.

Assumptions	For the Year Ended December 31, 2020
Risk-free interest rate	1.4 %
Expected dividend yield	— %
Expected volatility	46.2 %
Expected term	2.75

The following table presents a summary of the Company's stock option activity for the year ended December 31, 2020:

	Number of Shares (In thousands)	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term(years)	Aggregate Intrinsic Value (in millions)
Outstanding at December 31, 2019	—	$ —	—	$ —
Granted	245	—		
Forfeited / Canceled	(154)	—		
Outstanding at December 31, 2020 (1)	91	$ —	2.68	$ 0.24
Exercisable at December 31, 2020	—	$ —	—	$ —

(1) All outstanding stock options as of December 31, 2020, are expected to vest.

In February 2020, the Company, granted nonqualified stock options. As of December 31, 2020, the total unrecognized compensation expense was immaterial and will be recognized over a weighted average period of 2.18 years. No options vested during the year ended December 31, 2020.

The following tables summarize the Company's share and incentive-based compensation for the years ended December 31, 2020 and 2019 (in thousands):

	Recurring Compensation Expense(1)	Executive Terminations(2)	Reduction in Force(2)	Accelerated Vesting(3)	Total
Year Ended December 31, 2020					
Equity-classified awards:					
Restricted stock awards and units	$ 974	$ 508	$ 40	$ —	$ 1,522
Performance share units	211	1,276	—	—	1,487
Stock options	22	—	—	—	22
Total share-based compensation expense	1,207	1,784	40	—	3,031
Less: Capitalized compensation expense	(19)	—	—	—	(19)
Share and incentive-based compensation expense, net	$ 1,188	$ 1,784	$ 40	$ —	$ 3,012
Year Ended December 31, 2019					
Equity-classified awards:					
Restricted stock awards	$ 2,526	$ 197	$ 500	$ —	$ 3,223
Performance share units	282	281	—	—	563
Stock options	661	12	—	—	673
Total share-based compensation expense	3,469	490	500	—	4,459
Less: Capitalized compensation expense	(204)	—	—	—	(204)
Share and incentive-based compensation expense, net	$ 3,265	$ 490	$ 500	$ —	$ 4,255

(1) Recorded in general and administrative expense in the accompanying consolidated statements of operations.
(2) Recorded in employee termination benefits in the accompanying consolidated statements of operations.
(3) Recorded in accelerated vesting of employment compensation in the accompanying consolidated statements of operations.

18. Incentive and Deferred Compensation Plans

Annual Incentive Plan. The Annual Incentive Plan ("AIP") incorporates quantitative performance measures, strategic qualitative goals and competitive target award levels for management and employees for the 2020 and 2019 performance years. Incentive bonus awards for 2020 will be provided at the discretion of the Board of Directors and will be paid in 2021. As of December 31, 2020, the Company had accrued approximately $2.6 million for the 2020 AIP. AIP Payments totaling $1.1 million were paid in 2020 for the 2019 performance year.

401(k) Plan. 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 the IRS. For the years ended December 31, 2020 and 2019, the Company made matching contributions to the plan equal to 100% on the first 10% of employee deferred wages, excluding incentive compensation, totaling $1.1 million and $2.2 million, respectively. The decrease in contributions is due primarily to reductions in force that occurred in each of those years. 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.

19. Employee Termination Benefits

The following table presents a summary of employee termination benefits for the years ended December 31, 2020 and 2019 (in thousands):

	Cash	Share-Based Compensation (4)	Number of Shares	Total Employee Termination Benefits
Year Ended December 31, 2020				
Executive Employee Termination Benefits (1)	$ 1,009	$ 1,784	159	$ 2,793
Other Employee Termination Benefits	5,600	40	4	5,640
	$ 6,609	$ 1,824	163	$ 8,433
Year Ended December 31, 2019				
Executive Employee Termination Benefits (2)	$ 1,194	$ 490	37	$ 1,684
Other Employee Termination Benefits (3)	2,608	500	44	3,108
	$ 3,802	$ 990	81	$ 4,792

(1) On July 1, 2020, the Company's then current Chief Financial Officer, Michael A. Johnson and Chief Operating Officer, John Suter, separated employment from the Company. As a result, the Company paid cash severance costs and incurred share-based compensation costs associated with these separations during 2020.

(2) On December 12, 2019, the Company's then current CEO, Paul McKinney, separated employment from the Company, and on June 14, 2019, the Company's then current Executive Vice President, General Counsel and Corporate Secretary, Philip Warman, separated employment from the Company. As a result, the Company paid cash severance costs and incurred share-based compensation costs associated with these separations during 2019.

(3) As a result of a reduction in workforce in the second quarter of 2019, certain employees received termination benefits including cash severance and accelerated share-based compensation upon separation of service from the Company.

(4) Share-based compensation recognized in connection with the accelerated vesting of restricted stock awards and performance share units upon the departure of certain executives and the reductions in workforce in 2020 and 2019 reflects the remaining unrecognized compensation expense associated with these awards at the date of termination. The unrecognized compensation expense was calculated using the grant date fair value for restricted stock awards and performance share units. One share of the Company's common stock was issued per performance share unit.

As of December 31, 2020 there were no longer any legacy employment contracts.

See Note 17 for additional discussion of the Company's share-based compensation awards.

20. Loss per Share

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

	Net Loss	Weighted Average Shares	Loss Per Share
	(In thousands, except per share amounts)		
Year Ended December 31, 2020			
Basic loss per share	$ (277,353)	35,689	$ (7.77)
Effect of dilutive securities			
Restricted stock awards (1)	—	—	—
Performance share units (1)	—	—	—
Warrants (1)	—	—	—
Diluted loss per share	$ (277,353)	35,689	$ (7.77)
Year Ended December 31, 2019			
Basic loss per share	$ (449,305)	35,427	$ (12.68)
Effect of dilutive securities			
Restricted stock awards (1)	—	—	—
Performance share units (1)	—	—	—
Warrants (1)	—	—	—
Diluted loss per share	$ (449,305)	35,427	$ (12.68)

(1) No incremental shares of potentially dilutive restricted stock awards, performance share units or warrants were included for the year ended December 31, 2020 and 2019, as their effect was antidilutive under the treasury stock method.

See Note 17 for discussion of the Company's share-based compensation awards.

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

The supplemental information below 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):

	December 31,	
	2020	2019
Oil and natural gas properties		
Proved	$ 1,463,950	$ 1,484,359
Unproved	17,964	24,603
Total oil and natural gas properties	1,481,914	1,508,962
Less accumulated depreciation, depletion and impairment	(1,375,692)	(1,129,622)
Net oil and natural gas properties capitalized costs	$ 106,222	$ 379,340

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):

	Year Ended December 31,	
	2020	2019
Acquisitions of properties		
Proved	$ 3,701	$ (210)
Unproved	—	2,653
Exploration	1,005	2,900
Development	3,563	156,210
Total cost incurred	$ 8,269	$ 161,553

Results of Operations for Oil and Natural Gas Producing Activities

The following table presents the Company's results of operations from oil and natural gas producing activities (in thousands), which exclude any interest costs or indirect general and administrative costs and, therefore, are not necessarily indicative of the impact the Company's operations have on actual net earnings.

	Year Ended December 31,	
	2020	2019
Revenues	$ 114,450	$ 266,104
Expenses		
Production costs	53,474	110,711
Depreciation and depletion	50,349	146,874
Impairment	218,399	409,574
Total expenses	322,222	667,159
Loss before income taxes	(207,772)	(401,055)
Income tax benefit (1)	(51,750)	(105,477)
Results of operations for oil and natural gas producing activities (excluding corporate overhead and interest costs)	$ (156,022)	$ (295,578)

(1) Income tax (benefit) expense is hypothetical and is calculated by applying the Company's statutory tax rate to (loss) income before income taxes attributable to our oil and natural gas producing activities, after giving effect to permanent differences and tax credits.

Oil, Natural Gas and NGL Reserve Quantities

Proved oil, natural gas and NGL reserves are those quantities, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, based on oil, natural gas and NGL prices used to estimate reserves, from a given date forward from known reservoirs, and under existing economic conditions, operating methods, and government regulation 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 NGLs actually recovered will equal or exceed the estimate. To achieve reasonable certainty, the Company's engineers and independent petroleum consultants relied on technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used to estimate the Company's proved reserves include, but are not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. 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 mandated economic assumptions; and
- the judgment of the personnel preparing the estimates.

Proved developed reserves are proved reserves expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well. Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively large major expenditure is required for recompletion.

The following table represents the Company's estimate of proved oil, natural gas and NGL reserves attributable to the Company's net interest in oil and natural gas properties, all of which are located in the continental United States, based upon the evaluation by the Company and its independent petroleum engineers of pertinent geoscience and engineering data in accordance with the SEC's regulations. Over 90% of the Company's proved reserves estimates have been prepared by independent reservoir engineers and geoscience professionals and are reviewed by members of the Company's senior management with professional training in petroleum engineering to ensure that the Company consistently applies rigorous professional standards and the reserve definitions prescribed by the SEC.

Cawley, Gillespie & Associates and Ryder Scott, independent oil and natural gas consultants, prepared the estimates of proved reserves of oil, natural gas and NGLs for over 90% of the Company's net interest in oil and natural gas properties as of the end of one or more of 2020 and 2019. Cawley, Gillespie & Associates and Ryder Scott are independent petroleum engineers, geologists, geophysicists and petrophysicists and do not own an interest in the Company or its properties and are not employed on a contingent basis. The remaining proved reserves were based on Company estimates.

The Company believes the geoscience and engineering data examined provides reasonable assurance that the proved reserves are economically producible in future years from known reservoirs, and under existing economic conditions, operating methods and governmental regulations. Estimates of proved reserves are subject to change, either positively or negatively, as additional information is available and contractual and economic conditions change.

2020 Activity. Proved reserves decreased from 89.9 MMBoe at December 31, 2019 to 36.9 MMBoe at December 31, 2020, primarily as a result of downward revisions of 45.0 MMBoe associated with the decrease in year-end SEC commodity prices for oil and natural gas consisting of (27.8 MMBoe from removing PUDs, and 17.3 MMBoe from remaining proved reserves). The Company also recorded 2020 production totaling 8.7 MMBoe and a decrease of 9.0 MMBoe attributable to well shut-ins, sales and other revisions. These reductions were partially offset by an 8.6 MMBoe increase associated with reduction in expenses and other commercial improvements, and purchases of 1.1 MMBoe of proved reserves.

2019 Activity. Proved reserves decreased from 160.2 MMBoe at December 31, 2018 to 89.9 MMBoe at December 31, 2019, primarily as a result of downward revisions of 50.9 MMBoe associated with the decrease in year-end SEC prices for oil and natural gas consisting of (i) 39.8 MMBoe from downgrading PUDs, and (ii) 11.1 MMBoe from remaining proved reserves. The Company also recorded a decrease of 10.9 MMBoe attributable to increased commodity price differentials, and a decrease of 3.2 MMBoe attributable to well performance. These reductions were partially offset by a 12.6 MMBoe increase associated with converting undeveloped well locations from SRLs to planned XRLs as well as reduced future estimated development capital on these undeveloped locations.

The summary below presents changes in the Company’s estimated reserves.

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)(1)	Total MBoe
Proved developed and undeveloped reserves				
As of December 31, 2018	64,019	28,175	407,891	160,176
Revisions of previous estimates	(25,530)	(9,277)	(142,239)	(58,514)
Extensions and discoveries	635	94	2,127	1,084
Sales of reserves in place	(297)	(223)	(2,308)	(905)
Production	(3,519)	(2,910)	(33,164)	(11,956)
As of December 31, 2019	35,308	15,859	232,307	89,885
Revisions of previous estimates	(24,650)	(2,246)	(107,426)	(44,800)
Acquisitions of new reserves	74	437	3,391	1,076
Sales of reserves in place	(163)	(111)	(1,827)	(579)
Production	(2,084)	(2,694)	(23,552)	(8,703)
As of December 31, 2020	8,485	11,245	102,893	36,879
Proved developed reserves				
As of December 31, 2019	14,078	14,532	200,853	62,086
As of December 31, 2020	8,485	11,245	102,893	36,879
Proved undeveloped reserves				
As of December 31, 2019	21,230	1,327	31,454	27,799
As of December 31, 2020	—	—	—	—

(1) Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

Standardized Measure of Discounted Future Net Cash Flows (Unaudited)

The standardized measure of discounted cash flows and summary of the changes in the standardized measure computation from year to year are prepared in accordance with ASC Topic 932, Extractive Activities—Oil and Gas, ("ASC Topic 932"). The assumptions underlying the computation of the standardized measure of discounted cash flows may be summarized as follows:

- the standardized measure includes the Company’s estimate of proved oil, natural gas and NGL reserves and projected future production volumes based upon economic conditions;
- pricing is applied based upon SEC prices at December 31, 2020 and 2019, adjusted for fixed or determinable contracts that are in existence at year-end. The calculated weighted average per unit prices for the Company’s proved reserves and future net revenues were as follows:

	At December 31, 2020	At December 31, 2019
Oil (per Bbl)	$ 36.54	$ 50.63
NGL (per Bbl)	$ 6.40	$ 12.45
Natural gas (per Mcf)	$ 0.87	$ 1.16

- future development and production costs are determined based upon actual cost at year-end;
- the standardized measure includes projections of future abandonment costs based upon actual costs at year-end; and
- a discount factor of 10% per year is applied annually to the future net cash flows.

The summary below presents the Company's future net cash flows relating to proved oil, natural gas and NGL reserves based on the standardized measure in ASC Topic 932 (in thousands).

	December 31,	
	2020	2019
Future cash inflows from production	$ 471,038	$ 2,254,530
Future production costs	(270,512)	(1,028,695)
Future development costs (1)	(81,687)	(536,081)
Future income tax expenses (2)	—	—
Undiscounted future net cash flows	118,839	689,754
10% annual discount	(13,853)	(325,464)
Standardized measure of discounted future net cash flows	$ 104,986	$ 364,290

(1) Includes abandonment costs.
(2) The future income tax expenses have been computed using statutory tax rates, giving effect to allowable tax deductions and tax credits under current laws, including expected tax benefits to be realized from the utilization of net operating loss carryforwards.

The following table represents the Company's estimate of changes in the standardized measure of discounted future net cash flows from proved reserves (in thousands):

	Year Ended December 31,	
	2020	2019
Beginning present value	$ 364,290	$ 1,045,603
Changes during the year		
Revenues less production	(61,407)	(155,772)
Net changes in prices, production and other costs	(135,652)	(491,035)
Development costs incurred	—	90,591
Net changes in future development costs (1)	(2,167)	450,162
Extensions and discoveries	—	11,921
Revisions of previous quantity estimates (1)	(99,533)	(478,238)
Accretion of discount	36,429	101,778
Purchases of reserves in-place	4,744	—
Sales of reserves in-place	(1,067)	(3,331)
Timing differences and other (2)	(651)	(207,389)
Net change for the year	(259,304)	(681,313)
Ending present value (3)	$ 104,986	$ 364,290

(1) The change in estimated future development costs and revisions of previous quantity estimates primarily reflect a decrease in planned PUD development due to declining year end SEC prices for oil and natural gas. The elimination of PUD development for the year ended December 31, 2020 resulted in a decrease of $73.8 million.
(2) The change in timing differences and other are related to revisions in the Company's estimated time of production and development.
(3) Standardized Measure was determined using SEC prices, and does not reflect actual prices received or current market prices.

22. Subsequent Events

On March 3, 2021, the Company named Mr. Grayson Pranin, formerly its Vice President for Reserves and Engineering, as Senior Vice President and Chief Operating Officer. The Company also named Mr. Salah Gamoudi, the Company’s Chief Financial Officer and Chief Accounting Officer, as a Senior Vice President. It also named Mr. Dean Parrish, formerly its Director of Operations, as its Vice President of Operations.

On February 5, 2021, the Company sold all of our oil and natural gas properties and related assets of the North Park Basin in Colorado for a purchase price of $47 million. The sale closed for net proceeds of $39.7 million in cash, which is net of effective to closing date adjustments.

North Park Basin ("NPB") for the year ended December 31, 2020, represented $31.1 million, or 27.0% of the Company's $115.0 million total consolidated Revenues, NPB represented $9.1 million, or 20.9% of the Company's $43.4 million consolidated Lease operating expense, it represented $1.8 million, or 18.7% of the Company's $9.6 million consolidated Production, ad valorem and other taxes, it represented $1.5 million or 18.1% of the Company's consolidated capital expenditures of $8.3 million and NPB represented 0.9 MMBoe, or 10.3% of the Company's consolidated total production volumes of 8.7 MMBoe.

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, 2020 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, 2020 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 April 30, 2021: "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 April 30, 2021: "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 April 30, 2021: "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 April 30, 2021: "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 April 30, 2021.

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 57.

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*

EXHIBIT INDEX

		Incorporated by Reference				
Exhibit No.	**Exhibit Description**	**Form**	**SEC File No.**	**Exhibit**	**Filing Date**	**Filed Herewith**
2.1	Amended Joint Chapter 11 Plan of Reorganization of SandRidge Energy, Inc., et al., dated September 19, 2016	8-A	001-33784	2.1	10/4/2016	
3.1	Amended and Restated Certificate of Incorporation of SandRidge Energy, Inc.	8-A	001-33784	3.1	10/4/2016	
3.2	Amended and Restated Bylaws of SandRidge Energy, Inc.	8-A	001-33784	3.2	10/4/2016	
3.3	Certificate of Designations of Series B Participating Preferred Stock of SandRidge Energy, Inc.	8-K	001-33784	3.1	11/27/2017	
3.4	Certificate of Designation of Series A Junior Participating Preferred Stock of SandRidge Energy, Inc., as filed with the Secretary of State of Delaware	8-A	001-33784	3.1	44014	
4.1	Form of specimen Common Stock certificate of SandRidge Energy, Inc.	8-K	001-33784	4.1	10/7/2016	
4.2	Warrant Agreement, dated as of October 4, 2016, between SandRidge Energy, Inc. and American Stock Transfer & Trust Company, LLC, as warrant agent	8-K	001-33784	10.6	10/7/2016	
4.3	Registration Rights Agreement dated as of October 4, 2016, among SandRidge Energy, Inc. and the holders party thereto	8-A	001-33784	10.1	10/4/2016	
4.4	Stockholder Rights Agreement, dated as of November 26, 2017, between SandRidge Energy, Inc. as the Company, and American Stock Transfer & Trust Company, LLC as Rights Agent	8-K	001-33784	4.1	11/27/2017	
4.5	First Amendment to Stockholder Rights Agreement, dated as of January 22, 2018, by and between SandRidge Energy, Inc. and American Stock Transfer & Trust Company, LLC, as Rights Agent	8-K	001-33784	4.1	1/23/2018	
4.6	Description of Registrant's Securities					*
10.1†	SandRidge Energy, Inc. 2016 Omnibus Incentive Plan	8-K	001-33784	10.8	10/7/2016	
10.1.1†	Form of Restricted Stock Award Certificate and Agreement for SandRidge Energy, Inc. 2016 Omnibus Incentive Plan	10-K	001-33784	10.1.4	3/3/2017	

Exhibit No.	Exhibit Description	Incorporated by Reference Form	SEC File No.	Exhibit	Filing Date	Filed Herewith
10.1.1.1†	Form of Amendment No. 1 to the Restricted Stock Award Certificate and Agreement for SandRidge Energy, Inc. 2016 Omnibus Incentive Plan	10-Q	001-33784	10.1.4.1	11/3/2017	
10.1.2†	Form of Performance Share Unit Award Certificate and Agreement for SandRidge Energy, Inc. 2016 Omnibus Incentive Plan	10-K	001-33784	10.1.5	3/3/2017	
10.1.3†	Form of Non-employee Director Restricted Stock Award Certificate and Agreement for SandRidge Energy, Inc. 2016 Omnibus Incentive Plan	10-Q	001-33784	10.1.6	8/7/2017	
10.1.3.1†	Form of Amendment No. 1 to the Non-employee Director Restricted Stock Award Certificate and Agreement for SandRidge Energy, Inc. 2016 Omnibus Incentive Plan	10-Q	001-33784	10.1.6.1	11/3/2017	
10.1.4†	Form of Restricted Stock Award Certificate and Agreement (Double Trigger) for SandRidge Energy, Inc. 2016 Omnibus Incentive Plan	10-K	001-33784	10.1.7	2/22/2018	
10.1.5†	Form of Non-employee Director Restricted Stock Award Agreement for SandRidge Energy, Inc. 2016 Omnibus Incentive Plan, dated July 17, 2018	10-Q	001-33784	10.1.1	11/8/2018	
10.2†	Amended and Restated SandRidge Energy, Inc. 2016 Omnibus Incentive Plan, dated August 8, 2018	10-Q	001-33784	10.1	11/8/2018	
10.2.1†	Form of Executive Restricted Stock Award Agreement for Amended and Restated SandRidge Energy, Inc. 2016 Omnibus Incentive Plan	10-Q	001-33784	10.1.2	11/8/2018	
10.2.2†	Form of Performance Share Unit Award Agreement for Amended and Restated SandRidge Energy, Inc. 2016 Omnibus Incentive Plan	10-Q	001-33784	10.1.3	11/8/2018	
10.2.3†	Form of Option Award Agreement for Amended and Restated SandRidge Energy, Inc. 2016 Omnibus Incentive Plan	10-K	001-33784	10.2.3	3/4/2019	
10.3†	2015 Form of Employment Agreement for Executive Vice Presidents and Senior Vice Presidents of SandRidge Energy, Inc.	10-Q	001-33784	10.3.4	11/5/2015	
10.4†	The SandRidge Energy, Inc. Special Severance Plan	10-Q	001-33784	10.3.7	5/09/2019	
10.4.1†	First Amendment to the SandRidge Energy, Inc. Special Severance Plan	10-Q	001-33784	10.3.8	5/09/2019	
10.4.2†	Second Amendment to the SandRidge Energy, Inc. Special Severance Plan	10-K	001-33784	10.4.2	2/27/2020	
10.5†	Form of Indemnification Agreement for directors and officers	8-K	001-33784	10.9	10/7/2016	
10.6	Amended and Restated Credit Agreement, dated as of June 21, 2019, among SandRidge Energy, Inc., Royal Bank of Canada, as Administrative Agent, and the other lenders party thereto filed as Exhibit A to the Refinancing Amendment No. 2 to the Existing Credit Agreement	8-K	001-33784	10.1	6/27/2019	
10.7	Pledge and Security Agreement, dated as of October 4, 2016, by SandRidge Energy, Inc., the other grantors party thereto, and Royal Bank of Canada, as Administrative Agent	10-K	001-33784	10.6	3/3/2017	
10.8	Intercreditor and Subordination Agreement, dated as of October 4, 2016, among SandRidge Energy, Inc., Royal Bank of Canada, as priority lien agent, and Wilmington Trust, National Association, as the subordinated collateral trustee	8-K	001-33784	10.4	10/7/2016	

Exhibit No.	Exhibit Description	Incorporated by Reference Form	SEC File No.	Exhibit	Filing Date	Filed Herewith
10.9	Collateral Trust Agreement, dated as of October 4, 2016, among SandRidge Energy, Inc., the guarantors from time to time party thereto, Wilmington Trust, National Association, as Trustee under the Indenture, the other Parity Lien Representatives from time to time party thereto and Wilmington Trust, National Association, as Collateral Trustee	8-K	001-33784	10.5	10/7/2016	
10.10.1	Settlement Agreement, dated June 19, 2018, by and among SandRidge Energy, Inc., Carl C. Icahn, Icahn Partners LP, Icahn Partners Master Fund LP, Icahn Enterprises G.P. Inc., Icahn Enterprises Holdings L.P., IPH GP LLC, Icahn Capital L.P., Icahn Onshore LP, Icahn Offshore LP, Beckton Corp., High River Limited Partnership, Hopper Investments LLC and Barberry Corp. and Bob Alexander, Sylvia K. Barnes, Jonathan Christodoro, William M. Griffin, Jr., John “Jack” Lipinski and Randolph Read	8-K	001-33784	10.1	6/19/2018	
10.10.2	Confidentiality Agreement, dated June 22, 2018, by and among SandRidge Energy, Inc., Carl C. Icahn, High River Limited Partnership, Hopper Investments LLC, Barberry Corp., Icahn Partners LP, Icahn Partners Master Fund LP, Icahn Enterprises G.P. Inc., Icahn Enterprises Holdings L.P., IPH GP LLC, Icahn Capital LP, Icahn Onshore LP, Icahn Offshore LP, Beckton Corp, Jesse Lynn and Louie Pastor	8-K	001-33784	10.2	6/19/2018	
10.11**†	Letter Agreement, dated February 21, 2020, by and between the Company and John Suter	10-K	001-33784	10.11	2/27/2020	
10.11	Letter Agreement, dated April, 2020, by and between the Company and Carl F. Giesler, Jr.	8-K	001-33784	10.1	4/7/2020	
10.13	Real Estate Purchase and Sale Agreement, dated May 15, 2020, by and between Robinson Park, LLC and SandRidge Realty LLC	8-K	001-33784	10.1	5/19/2020	
10.14	Tax Benefits Preservation Plan, dated July 1, 2020, between SandRidge Energy, Inc. and American Stock Transfer & Trust Company, LLC as Rights Agent	8-K	001-33784	4.1	7/2/2020	
10.15	Letter Agreement, dated April 24, 2020, by and between the Company and Salah Gamoudi	8-K	001-33784	10.1	7/2/2020	
10.16	Credit Agreement, by and among SandRidge Energy, Inc. and Icahn Agency Services LLC dated as of November 30, 2020.	8-K	001-33784	10.1	12/1/2020	
10.17	Purchase and Sale Agreement by and between SandRidge Energy, Inc. and Gondola Resources, LLC, dated December 11, 2020	8-K	001-33784	2.1	12/14/2020	
21.1	Subsidiaries of SandRidge Energy, Inc.					*
22.1	Subsidiary Guarantors and Issuers of Guaranteed Securities					*
23.1	Consent of Deloitte & Touche LLP					*
23.2	Consent of Cawley, Gillespie & Associates					*
23.3	Consent of Ryder Scott Company, L.P.					*
31.1	Section 302 Certification-Chief Executive Officer					*
31.2	Section 302 Certification-Chief Financial Officer					*
32.1	Section 906 Certifications of Chief Executive Officer and Chief Financial Officer					*
99.1	Report of Cawley, Gillespie & Associates					*
99.2	Report of Ryder Scott Company, L.P.					*

Exhibit No.	Exhibit Description	Incorporated by Reference Form	SEC File No.	Exhibit	Filing Date	Filed Herewith
101.INS	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.					*
101.SCH	XBRL Taxonomy Extension Schema Document					*
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document					*
101.DEF	XBRL Taxonomy Extension Definition Document					*
101.LAB	XBRL Taxonomy Extension Label Linkbase Document					*
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document					*

** Portions of this exhibit have been redacted pursuant to a confidential treatment request filed with the SEC.

† Management contract or compensatory plan or arrangement

Item 16. ***Form 10-K Summary***

Not Applicable.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

SANDRIDGE ENERGY, INC.

By /s/ Carl F. Giesler, Jr.

Carl F. Giesler, Jr.
President and Chief Executive Officer

March 4, 2021

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Carl F. Giesler, Jr. and Salah Gamoudi and each of them severally, his true and lawful attorney or attorneys-in-fact and agents, with full power to act with or without the others and with full power of substitution and resubstitution, to execute in his name, place and stead, in any and all capacities, any or all amendments to this report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents and each of them, full power and authority to do and perform in the name of on behalf of the undersigned, in any and all capacities, each and every act and thing necessary or desirable to be done in and about the premises, to all intents and purposes and as fully as they might or could do in person, hereby ratifying, approving and confirming all that said attorneys-in-fact and agents or their substitutes may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ CARL F. GIESLER, JR. **Carl F. Giesler, Jr.**	President and Chief Executive Officer (Principal Executive Officer)	March 4, 2021
/s/ SALAH GAMOUDI **Salah Gamoudi**	Senior Vice President, Chief Financial Officer and Chief Accounting Officer (Principal Financial and Accounting Officer)	March 4, 2021
/s/ PATRICIA A. AGNELLO **Patricia A. Agnello**	Director	March 4, 2021
/s/ JONATHAN CHRISTODORO **Jonathan Christodoro**	Director	March 4, 2021
/s/ JONATHAN FRATES **Jonathan Frates**	Chairman	March 4, 2021
/s/ JOHN J. LIPINSKI **John J. Lipinski**	Director	March 4, 2021
/s/ RANDOLPH C. READ **Randolph C. Read**	Director	March 4, 2021

Exhibit 4.6

DESCRIPTION OF THE REGISTRANT'S SECURITIES REGISTERED PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

The following summary describes the securities of SandRidge Energy, Inc., ("we," "our," and "us") registered under Section 12 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). As of December 31, 2020, we have one class of securities; common stock.

Description of Common Stock

The following summary of the material terms of our securities is not intended to be a complete summary of the rights and preferences of such securities securities and is qualified in its entirety by reference to our Certificate of Incorporation and our Bylaws, and by applicable provisions of the Delaware General Corporation Law (the "DGCL"). We urge you to read our Amended and Restated Certificate of Incorporation (the "Certificate of Incorporation") and our Amended and Restated Bylaws (the "Bylaws") in their entirety for a complete description of the rights and preferences of our securities, copies of which have been filed with the SEC, as well as the applicable provisions of the DGCL for additional information. The Certificate of Incorporation and Bylaws are also incorporated by reference as an exhibit to the Annual Report on Form 10-K of which this Exhibit 4.6 is a part.

Authorized Capitalization

Our authorized capital stock consists of 300,000,000 shares, which include 250,000,000 shares of common stock, par value $0.001 par value per share (the "common stock") and 50,000,000 shares of preferred stock, par value $0.001 per share (the "preferred stock").

As of December 31, 2020, there were approximately 35,928,429 issued and outstanding shares of common stock and no shares of preferred stock issued and outstanding. All of the shares of common stock are duly authorized, validly issued, fully paid and non-assessable. Pursuant to the Bylaws and subject to any resolution of the stockholders, the Board is authorized to issue any of our authorized but unissued capital stock.

Common Stock

Dividends

Subject to the rights granted to any holders of the preferred stock, holders of the common stock will be entitled to dividends in the amounts and at the times declared by our Board in our discretion out of any assets or our funds legally available for the payment of dividends.

Voting

Each holder of shares of the common stock is entitled to one vote for each share of the common stock on all matters presented to our stockholders (including the election of directors). Our common stock does not have cumulative voting rights. Uncontested elections of directors are decided by a majority of the votes cast with respect to that director's election, and contested elections of directors are decided by a plurality of the votes cast present in person or represented by proxy,

Liquidation

The holders of the common stock will share equally and ratably in our assets on liquidation after payment or provision for all liabilities and any preferential liquidation rights of any preferred stock then outstanding.

Other Rights

The holders of the common stock do not have preemptive rights to purchase shares of our common stock. The common stock is not convertible, redeemable, assessable or entitled to the benefits of any sinking or repurchase fund. The rights, preferences and privileges of holders of the common stock will be subject to those of the holders of any shares of preferred stock that we may issue in the future.

Under the terms of the Certificate of Incorporation and the Bylaws, we are prohibited from issuing any non-voting equity securities to the extent required under Section 1123(a)(6) of the Bankruptcy Code and only for so long as Section 1123 of the Bankruptcy Code is in effect and applicable to us.

Listing

The common stock is traded on the New York Stock Exchange under the trading symbol "SD."

Change in Control Effects of Certain Provisions

Our Certificate of Incorporation, Bylaws, and the DGCL contain certain provisions that could delay, defer, or prevent a change in control by means of merger, reorganization, liquidation, tender offer, sale, transfer of substantially all of our assets, or otherwise.

Advance Notice of Director Nominations and Matters to be Acted Upon at Meetings

Our Bylaws contain advance notice requirements for nominations for directors to our Board of Directors and for proposing matters that can be acted upon by stockholders at stockholder meetings.

Amendment to Bylaws

Our Certificate of Incorporation provides that our Bylaws may be adopted, amended, restated, or repealed by the Board of Directors; provided no bylaw adopted by the stockholders can be amended, repealed, or readopted by the Board of Directors if such bylaw provides that it may not be amended, repealed, or readopted by the Board of Directors. The Certificate of Incorporation also provides that that the Bylaws may not be adopted, amended, restated or repealed by the stockholders except by the vote of holders of a majority in voting power of the outstanding shares of stock entitled to vote, voting together as a single class.

Special Meeting of Stockholders

Our Certificate of Incorporation provides that a special meeting of our stockholders may be called only by the Chief Executive Officer, the Chairman of the Board of Directors, the Board of Directors pursuant to a resolution adopted by a majority of the total number of directors that the Corporation would have if there were no vacancies or by the Secretary of the Corporation at the written request or requests of holders of record of at least twenty-five percent (25%) of the voting power of the outstanding capital stock entitled to vote at the time of such written request pursuant to the procedures set forth in the Bylaws.

Limits on Ability of Stockholders to Act by Written Consent

Our Bylaws provide that any action required or permitted to be taken at any annual or special meeting of stockholders may be taken only upon the vote of stockholders at an annual or special meeting duly noticed and called in accordance with the Bylaws, the Certificate of Incorporation, and the DGCL and may not be taken by written consent of the stockholders without a meeting.

Exhibit 21.1

SANDRIDGE ENERGY, INC. SUBSIDIARIES

Entity Name	State of Organization
Lariat Services, Inc.	Texas
SandRidge Exploration and Production, LLC	Delaware
SandRidge Holdings, Inc.	Delaware
SandRidge Midstream, Inc.	Texas
SandRidge Operating Company	Texas
SandRidge Realty, LLC	Oklahoma

Exhibit 22.1

SANDRIDGE ENERGY INC.
SUBSIDIARY GUARANTORS AND ISSUERS OF GUARANTEED SECURITIES

Guaranteed Securities
$30 million Credit Facility

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-232769 on Form S-3 and Registration Statement No. 333-214383 on Form S-8 of our report dated March 4, 2021 relating to the consolidated financial statements of SandRidge Energy, Inc. and subsidiaries appearing in this Annual Report on Form 10-K for the year ended December 31, 2020.

/s/ Deloitte & Touche LLP
Houston, Texas
March 4, 2021

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the use by SandRidge Energy, Inc. (the “Company”), of our name and to the inclusion of information taken from the reports listed below in the Company’s Annual Report on Form 10-K for the year ended December 31, 2020, including any amendments thereto, filed with the U.S. Securities and Exchange Commission on or about March 4, 2021, as well as to the incorporation by reference thereof into the Company’s Registration Statement on Form S-8 (File No. 333-214383) and Form S-3 (File No. 333-232769), including any amendments thereto, in accordance with the requirements of the Securities Act of 1933, as amended:

December 31, 2020, SandRidge Energy, Inc. Interest in Certain Properties located in the United States — SEC Price Case

December 31, 2019, SandRidge Energy, Inc. Interest in Certain Properties located in the United States — SEC Price Case

December 31, 2018, SandRidge Energy, Inc. Interest in Certain Properties located in the United States — SEC Price Case

December 31, 2017, SandRidge Energy, Inc. Interest in Certain Properties located in the United States — SEC Price Case

CAWLEY, GILLESPIE & ASSOCIATES, INC.

J. Zane Meekins
Executive Vice President

Fort Worth, Texas
March 4, 2021

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580

633 17 STREET, SUITE 1700 DENVER, COLORADO 80202 (303) 339-8110

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the use by SandRidge Energy, Inc. (the "Company"), of our name and to the inclusion of information taken from the reports listed below in the Company's Annual Report on Form 10-K for the year ended December 31, 2020, filed with the U.S. Securities and Exchange Commission on or about March 4, 2021, as well as to the incorporation by reference thereof into the Company's Registration Statement on Form S-8 (File No. 333-214383) and Form S-3 (File No. 333-232769), including any amendments thereto, in accordance with the requirements of the Securities Act of 1933, as amended:

December 31, 2020, SandRidge Energy, Inc. Interest in Certain Properties located in the United States — SEC Price Case
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December 31, 2017, SandRidge Energy, Inc. Interest in Certain Properties located in the United States — SEC Price Case

Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.

Denver, Colorado

March 4, 2021

Exhibit 31.1

Certification of the Company's Chief Executive Officer Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241)

I, Carl F. Giesler, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of SandRidge Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Carl F. Giesler, Jr.

Carl F. Giesler, Jr.

President and Chief Executive Officer

Date: March 4, 2021

Exhibit 31.2

Certification of the Company's Chief Financial Officer Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241)

I, Salah Gamoudi, certify that:

1. I have reviewed this annual report on Form 10-K of SandRidge Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Salah Gamoudi

Salah Gamoudi
Senior Vice President, Chief Financial Officer and Chief Accounting Officer

Date: March 4, 2021

Exhibit 32.1

Certification of the Company's Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)

Pursuant to 18 U.S.C. § 1350, the undersigned officers of SandRidge Energy, Inc. (the "Company"), hereby certify that the Company's Annual Report on Form 10-K for the year ended December 31, 2020 (the "Report"), fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934 and that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

March 4, 2021

/s/ Carl F. Giesler, Jr.
Carl F. Giesler, Jr.
President and Chief Executive Officer

March 4, 2021

/s/ Salah Gamoudi
Salah Gamoudi
Senior Vice President, Chief Financial Officer and Chief Accounting Officer

Exhibit 99.1

CAWLEY, GILLESPIE & ASSOCIATES, INC.
PETROLEUM CONSULTANTS

302 FORT WORTH CLUB BUILDING
306 WEST SEVENTH STREET
FORT WORTH, TEXAS 76102-4987
(817) 336-2461

January 21, 2021

Mr. Grayson R. Pranin
SandRidge Energy, Inc.
1 East Sheridan Avenue
Oklahoma City, Oklahoma 73104

Re: Evaluation Summary
SandRidge Energy, Inc. Interests
Proved Reserves
As of January 1, 2021

Dear Mr. Pranin:

As requested, we are submitting our estimates of proved reserves and our forecasts of the resulting economics attributable to the SandRidge Energy, Inc. ("SandRidge") interests in certain oil and gas properties located in Kansas and Oklahoma. The net reserves and future net revenue for SandRidge have been estimated using the proportional consolidation method with respect to the SandRidge Mississippian Trust I. Under the proportional consolidation method and for the properties in which the Trust has an interest, SandRidge's interest share of revenues, expenses, investments and liabilities includes both Sandridge's direct interest in the properties and SandRidge's revenue interest share of the Trust. It is our understanding that the proved reserves estimated in this report constitute approximately 74 percent of all proved reserves owned by SandRidge. This report, completed on January 25, 2021, has been prepared for use in filings with the U.S. Securities and Exchange Commission by SandRidge.

Composite reserve estimates and economic forecasts for the proved reserves to the SandRidge proportional consolidation interests are summarized below:

		Proved Developed Producing	Proved Developed Non-Producing	Proved
Net Reserves				
Oil/Condensate	- Mbbl	3,361	93	3,454
Gas	- MMcf	82,238	2,716	84,953
NGL	- Mbbl	9,258	274	9,532
Revenue				
Oil/Condensate	- M$	127,935	3,523	131,457
Gas	- M$	70,955	2,343	73,298
NGL	- Mbbl	58,612	1,735	60,347
Operating Income (BFIT)	- M$	29,192	458	29,651
Discounted @ 10%	- M$	49,261	173	49,433

In accordance with the Securities and Exchange Commission guidelines, the operating income (BFIT) has been discounted at an annual rate of 10% to determine its “present worth”. The discounted value, “present worth”, shown above should not be construed to represent an estimate of the fair market value by Cawley, Gillespie & Associates, Inc. For the properties in which the Trust has an interest, SandRidge is obligated to act as a reasonably prudent operator by disregarding the existence of the Trust royalty interests as burdens affecting the properties. Therefore, the economic viability of these properties has been evaluated based on economic limits when combining the SandRidge direct interest and the Trust total royalty interest.

The annual average Henry Hub spot market gas price of $1.99 per MMBtu and the annual average WTI Cushing spot oil price of $39.57 per barrel were used in this report. In accordance with the Securities and Exchange Commission guidelines, these prices are determined as an unweighted arithmetic average of the first-day-of-the-month price for each month of 2020. The oil and gas prices were held constant and were adjusted for gravity, heating value, quality, transportation and regional price differentials. The adjusted volume-weighted average product prices over the life of the properties are $38.06 per barrel of oil, $6.33 per barrel of NGL and $0.86 per Mcf of gas.

Operating costs were based on operating expense records of SandRidge. For non-operated properties, these costs include the overhead expenses allowed under existing joint operating agreements. Abandonment costs used in the report are estimates prepared by SandRidge to abandon the wells and production facilities, net of salvage value. As per the Securities and Exchange Commission guidelines, neither expenses nor investments were escalated.

The proved reserve classifications conform to criteria of the Securities and Exchange Commission as defined in pages 3-4 of the Appendix. The estimates of reserves in this report have been prepared in accordance with the definitions and disclosure guidelines set forth in the Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). The reserves and economics are predicated on the regulatory agency classifications, rules, policies, laws, taxes and royalties in effect on the date of this report as noted herein. In evaluating the information at our disposal concerning this report, we have excluded from our consideration all matters as to which the controlling interpretation may be legal or accounting, rather than engineering and geoscience. Therefore, the possible effects of changes in legislation or other Federal or State restrictive actions have not been considered. An on-site field inspection of the properties has not been performed. The mechanical operation or conditions of the wells and their related facilities have not been examined nor have the wells been tested by Cawley, Gillespie & Associates, Inc. Possible environmental liability related to the properties has not been investigated nor considered.

The reserves were estimated using a combination of the production performance, volumetric and analogy methods, in each case as we considered to be appropriate and necessary to establish the conclusions set forth herein. All reserve estimates represent our best judgment based on data available at the time of preparation and assumptions as to future economic and regulatory conditions. It should be realized that the reserves actually recovered, the revenue derived therefrom and the actual cost incurred could be more or less than the estimated amounts.

The reserve estimates were based on interpretations of factual data furnished by SandRidge. Ownership interests were supplied by SandRidge and were accepted as furnished. To some extent, information from public records has been used to check and/or supplement these data. The basic engineering and geological data were utilized subject to third party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data.

Cawley, Gillespie & Associates, Inc. is independent with respect to SandRidge as provided in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers (“SPE Standards”). Neither Cawley, Gillespie & Associates, Inc. nor any of its employees has any interest in the subject properties. Neither the employment to make this study nor the compensation is contingent on the results of our work or the future production rates for the subject properties.

Our work-papers and related data are available for inspection and review by authorized parties. The technical person responsible for the preparation of this report meets or exceeds the education, training, and experience requirements set forth in the SPE Standards.

Respectfully submitted,

Cawley, Gillespie & Assoc., Inc.

CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm F-693

JZM:ptn

SandRidge Energy, Inc.

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

SEC Parameters

As of

December 31, 2020

/s/ Scott J. Wilson

Scott J. Wilson, P.E., MBA
Colorado License No. 36112
Senior Vice President

[SEAL]
RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

January 21, 2021

SandRidge Energy, Inc.
1 E. Sheridan Avenue
Oklahoma City, OK 73104

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of SandRidge Energy, Inc. (SandRidge) as of December 31, 2020. The subject properties are located in the states of Colorado and Oklahoma. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 21, 2021 and presented herein, was prepared for public disclosure by SandRidge in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott account for a portion of SandRidge's total net proved reserves as of December 31, 2020. Based on information provided by SandRidge, the third party estimate conducted by Ryder Scott addresses 51 percent of the total proved net oil reserves, 8 percent of total proved net plant products reserves, and 8 percent of the total proved net gas reserves of SandRidge. When considered in discounted cash flow terms, the reserves values evaluated represent 42 percent of the FNI discounted at 10 percent.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2020, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
SandRidge Energy, Inc.
As of December 31, 2020

	Proved		
	Developed		Total
	Producing	Non-Producing	Proved
Net Reserves			
Oil/Condensate – MBarrels	4,097	206	4,303
Plant Products – MBarrels	921	0	921
Gas – MMCF	8,255	0	8,255
Income Data ($M)			
Future Gross Revenue	$152,749	$6,901	$159,650
Deductions	86,471	4,453	90,924
Future Net Income (FNI)	$ 66,278	$2,448	$ 68,726
Discounted FNI @ 10%	$ 42,041	$1,579	$ 43,620

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (MBarrels). All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of SandRidge. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, certain abandonment costs net of salvage (shown as “Other Deductions”), and development costs. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist, nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 95 percent and gas reserves account for the remaining 5 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at five other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2020
Discount Rate Percent	Total Proved
7.5	$47,710
9.0	$45,147
15.0	$37,587
20.0	$33,326
25.0	$30,131

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed non-producing reserves included herein consist of the shut-in status category.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves, and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At SandRidge's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

SandRidge's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which SandRidge owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods, analogy, or a combination of methods. All of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods or a combination of methods. These performance methods include, but may not be limited to, decline curve analysis, material balance and/or reservoir simulation which utilized extrapolations of historical production and pressure data available through November 2020 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by SandRidge or obtained from public data sources and were considered sufficient for the purpose thereof.

All of the proved non-producing reserves included herein were estimated by analogy. The data utilized from the analogues were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

SandRidge has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by SandRidge with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by SandRidge. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by SandRidge. Wells that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of well completions and/or constraints set by regulatory bodies.

The future production rates from wells that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

SandRidge furnished us with the above mentioned average prices in effect on December 31, 2020. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by SandRidge. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by SandRidge to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
United States	Oil	WTI Cushing	$39.57/BBL	$35.06/BBL
	Plant Products	WTI Cushing	$39.57/BBL	$7.12/BBL (18% of WTI)
	Gas	Henry Hub	$1.985/MMBTU	$0.90/MCF

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by SandRidge and are based on the operating expense reports of SandRidge and include only those costs directly applicable to the leases or wells. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by SandRidge. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs for equipment to improve field gas processing from existing producing wells were furnished to us by SandRidge and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. SandRidge’s estimates of abandonment costs after salvage value for onshore properties were used in this report and are reported in the “Other Deductions ” column. Ryder Scott has not performed a detailed study of the abandonment costs or the salvage value and makes no warranty for SandRidge’s estimate.

The proved non-producing reserves in this report have been incorporated herein in accordance with SandRidge’s plans to bring these non-producing reserves to production as of December 31, 2020. The implementation of SandRidge’s plans to return these wells to production as presented to us and incorporated herein have been subjected to and received the internal approvals required by SandRidge’s management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to SandRidge. SandRidge has provided written documentation supporting their commitment to proceed with the non-producing well development activities as presented to us. Additionally, SandRidge has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2020, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by SandRidge were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to SandRidge. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by SandRidge.

SandRidge makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, SandRidge has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Forms S-3 and S-8 of SandRidge, of the references to our name, as well as to the references to our third party report for SandRidge, which appears in the December 31, 2020 annual report on Form 10-K of SandRidge. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by SandRidge.

We have provided SandRidge with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by SandRidge and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

/s/ Scott J. Wilson

Scott J. Wilson, P.E., MBA
Colorado License No. 36112
Senior Vice President **[SEAL]**

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Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Scott James Wilson was the primary technical person responsible for the estimate of the reserves, future production, and income presented herein.

Mr. Wilson, an employee of Ryder Scott Company L.P. (Ryder Scott) since 2000, is a Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Wilson served in a number of engineering positions with Atlantic Richfield Company. For more information regarding Mr. Wilson's geographic and job specific experience, please refer to the Ryder Scott Company website at https://www.ryderscott.com/company/employees/denver-employees.

Mr. Wilson earned a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines in 1983 and an MBA in Finance from the University of Colorado in 1985, graduating from both with High Honors. He is a registered Professional Engineer by exam in the States of Alaska, Colorado, Texas, and Wyoming. He is also an active member of the Society of Petroleum Engineers; serving as co-Chairman of the SPE Reserves and Economics Technology Interest Group, and Gas Technology Editor for SPE's Journal of Petroleum Technology. He is a member and past chairman of the Denver section of the Society of Petroleum Evaluation Engineers. Mr. Wilson has published several technical papers, one chapter in Marine and Petroleum Geology and two in SPEE monograph 4, which was published in 2016. He is the primary inventor on four US patents and won the 2017 Reservoir Description and Dynamics award for the SPE Rocky Mountain Region.

In addition to gaining experience and competency through prior work experience, several state Boards of Professional Engineers require a minimum number of hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Wilson fulfills as part of his registration in four states. As part of his continuing education, Mr. Wilson attends internally presented training as well as public forums relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, and Final Rule released January 14, 2009 in the Federal Register. Mr. Wilson attends additional hours of formalized external training covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering and petroleum economics evaluation methods, procedures and software and ethics for consultants.

Based on his educational background, professional training and more than 35 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Wilson has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the “Modernization of Oil and Gas Reporting; Final Rule” in the Federal Register of National Archives and Records Administration (NARA). The “Modernization of Oil and Gas Reporting; Final Rule” includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The “Modernization of Oil and Gas Reporting; Final Rule”, including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the “SEC regulations”. The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

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

Note to paragraph (a)(26): 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).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. 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.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) 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.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) 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.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) 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

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) 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.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are 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.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:

(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are 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 shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.*
>
> *(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.*
>
> *(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, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.*